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Republic of Indonesia

The Indonesia Carbon Capture Storage (CCS) Capacity Building Program

CCS for Coal-fired Power Plants in Indonesia

June 2015

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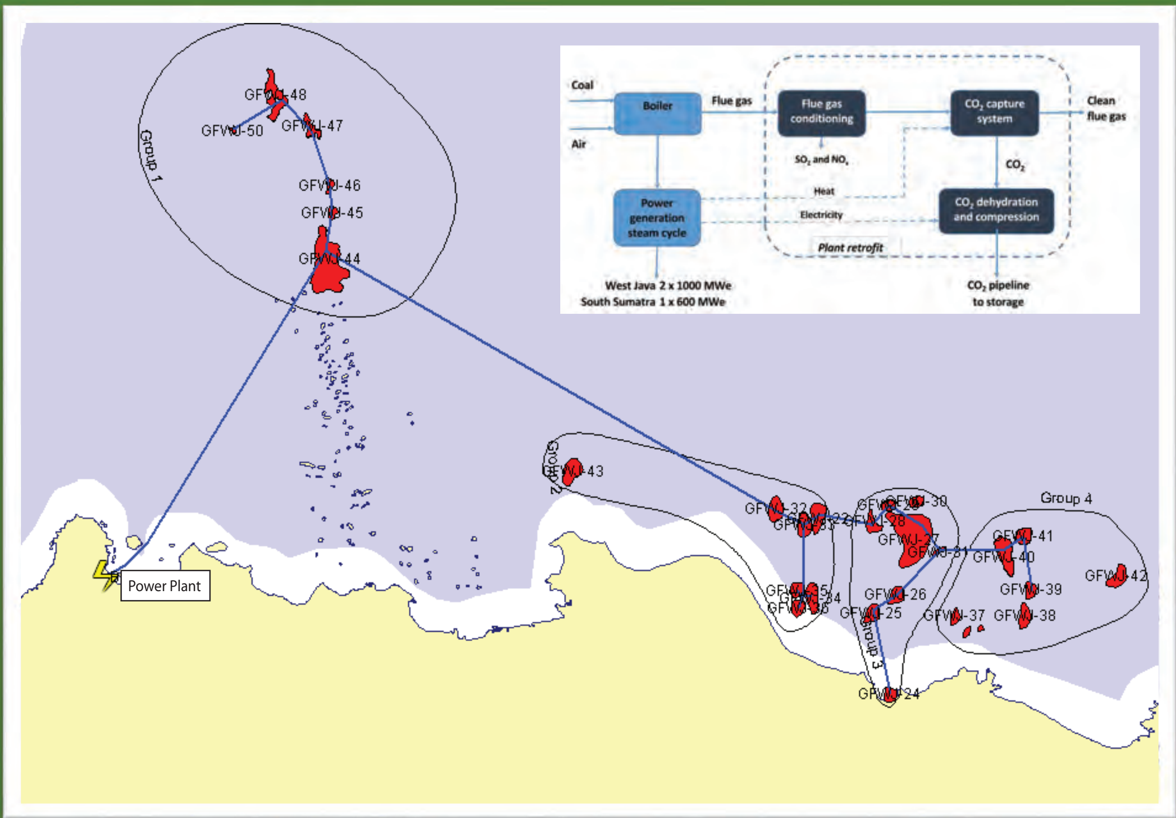
Carbon Capture and Storage for Coal-Fired Power Plants in Indonesia



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ABSTRACT

In order to meet the growing Indonesian demand for electricity, while also constraining carbon dioxide (CO_2) emissions, future coal power plants may have to include CO_2 capture equipment with storage of that CO_2. This study set out to define and evaluate the conditions under which fossil fuel power plants could be deemed as carbon capture and storage (CCS) ready (CCS-R). It considers the technical, economic and institutional implications of CO_2 capture and storage for candidate power plants in South Sumatra and West Java. The potential to sell captured CO_2 for Enhanced Oil Recovery (EOR) in South Sumatra is reviewed.

Key findings are:

- A technically feasible process for CO_2 capture (post-combustion) has been identified for use in existing plants (through retrofitting);
- To be capture-ready, a power plant's design would need to recognize future implementation of CO_2 capture and reserve space for additional equipment;
- CO_2 capture would involve a large loss of electricity output from the power plant;
- There is sufficient storage capacity for CO_2 in depleted gas wells for the cases studied;
- In the long term CCS would become constrained by available CO_2 storage capacity;
- The cost of electricity would about double with the addition of full CCS, which would cost about US$100 per tonne of CO_2 emission avoided;
- Assessment of partial CO_2 capture indicated that the cost per tonne of CO_2 captured would increase, due to sub-optimal use of equipment;
- Coal-fired power with full CCS is comparable in cost to geothermal power generation in Indonesia;
- The South Sumatra power plant is well placed to take advantage of EOR opportunities, but the West Java power plant is not;
- A co-benefit of the installation of CO_2 capture is a reduction in emission of local pollutants; and
- Policy recognition and institutional support is a key barrier to CCS implementation in Indonesia.

Recommendations are:

- CCS enabling policy incentives and a supportive regulatory environment should be created;
- Measures to bridge the financial viability gap and improve confidence in the technology should be pursued; and
- Capacity building and CCS awareness initiatives should be undertaken.

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*The Volume of Annexes is available, in electronic (pdf) format only, from the World Bank via Masaki Takahashi (mtakahashi@worldbank.org)

ABBREVIATIONS AND ACRONYMS

ADB	Asian Development Bank
bbl	Barrel of oil
BOE	Barrel of oil equivalent (=5.86 GJ)
BSCF	Billion standard cubic feet
Btu	British thermal unit (= 1054 Joules)
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCR	Capital Cost Recovery
CCS	Carbon Capture and Storage
CCS-R	Carbon Capture and Storage-Ready
CFPP	Coal-Fired Power Plant
CO_2	Carbon dioxide
cm^3	Cubic centimetre
EOR	Enhanced Oil Recovery
FGD	Flue Gas Desulphurization
FTP I / II	First / Second Fast Track Program
GHG	Greenhouse Gas
GJ / GJ_{hhv}	Gigajoules / Gigajoules on a higher heating value (hhv) basis
gm	grams
GoI	Government of Indonesia
GW	Gigawatt
HHV (or hhv)	Higher Heating Value (= Gross Calorific Value)
HV	High Voltage
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IJGCC	International Journal of Greenhouse Gas Control
IMF	International Monetary Fund
IPP	Independent Power Producer
JICA	Japanese International Cooperation Agency
kg	kilogram
kWh	Kilowatt hour
LCOE	Levelized Cost of Electricity
LEMIGAS	*Lembaga Minyakdan Gas Bumi* (R&D Center for oil and gas technology)
lhv	Lower Heating Value (= Net Calorific Value)
LNG	Liquefied Natural Gas
LP	Low Pressure
LSFO	Limestone Forced Oxidation (FGD system)
m	metre
mg	milligram
MMBOE	Million Barrels of Oil Equivalent (= 5.86 Petajoules)
MMBtu	Million British thermal units (= 1.054 GJ)
MDEA	Methyldiethanolamine

MEA	Monoethanolamine
MEMR	Minister of Energy and Mineral Resources
MMscfd	Million standard cubic feet per day
MWe	Megawatts of electricity
MWh	Megawatt hour
NGCC	Natural Gas Combined Cycle
Nm^3	Cubic metre at normal conditions (1 bar pressure and 0^oC)
NO_x	Oxides of Nitrogen (NO_2 [nitrogen dioxide], NO [nitric oxide], N_2O [nitrous oxide])
O_2	Oxygen
O&M	Operation and Maintenance
OOIP	Original Oil in Place
OPEX	Operating expenditure
P10 / P50 / P90	Resources with 10 percent / 50 percent / 90 percent probability
PLN	*PT Perusahaan Listrik Negara (Persero)* (national electric utility of Indonesia)
PPA	Power Purchase Agreement
ppm / ppmv	Parts per million / parts per million by volume
PSC	Production Sharing Contract
R&D	Research and Development
RAN-GRK	National Action Plan for Greenhouse Gas Reduction
RUPTL	Electricity Supply Business Plan
scf	Standard cubic feet
SCR	Selective Catalytic Reduction
SNG	Synthetic Natural Gas (from coal)
SO_2 / SO_3	Sulphur dioxide / sulphur trioxide
Tcf	Trillion standard cubic feet of natural gas (= 1.06 Petajoules)
tCO_2	Tonnes of carbon dioxide
TWh	Terawatt hour (= million Megawatt hours)
UK	United Kingdom (Britain)
US$	United States dollar
USA	United States of America
USC	Ultra – supercritical
USDOE	United States Department of Energy

EXECUTIVE SUMMARY

The purpose of this study is to support institutional capacity building for *PT Perusahaan Listrik Negara* (PLN), the national electric utility in Indonesia, and the Government of Indonesia (GoI) by developing awareness and expertise in the area of carbon capture and storage (CCS) in the power sector. CCS on fossil fuel power plants provides an opportunity to help the government to meet both its long term energy needs and commitments beyond its non-binding target[1] to reduce carbon dioxide (CO_2) emissions by 26 percent by 2020.

Indonesia's growing economy is demanding increased electricity generation capacity, which is predominantly based on coal as the least cost fuel for base load electricity generation. Indonesia's electricity outlook is that demand will increase by 8 percent per year over the decade from 2015 to 2024, with ongoing future growth. Thus, CO_2 emissions from the power sector are projected to increase substantially. This study identifies a way to reduce CO_2 emissions from the power sector in the long run, thus making a significant contribution to the sustainability of the power sector's development path.

In order to meet the GoI's goal of improved energy supply and security, while also constraining CO_2 emissions, future coal plants may have to include CO_2 capture equipment with CO_2 storage.

This study set out to define and evaluate the conditions under which fossil fuel power plants could be deemed as CCS-Ready (CCS-R). This study also presents PLN and related stakeholders with the technical, economic and institutional implications of CCS implementation in the power sector, based on post-combustion capture, which is the only practical technology for retrofitting to the candidate power plants. In addition, this study assesses Enhanced Oil Recovery (EOR)[2] as a potential cost-offsetting mechanism for CCS projects in the power sector.

This study of CCS in Indonesia's power sector is based on analysis of two candidate power plant designs: a 2x1000 MW lignite-fired power plant in West Java, using coal from or Kalimantan or Sumatra and a 1x600 MW power plant in South Sumatra located near a coal mine. These two power plants are assumed to be commissioned in 2020 and 2022, respectively.

A CCS reference case is evaluated for each power plant based on separation of 90 percent of the CO_2 from the power plant flue gas with a commercially proven amine scrubbing process, supported by flue gas cleaning processes, and liquefaction of the captured CO_2 for transportation to geological storage locations. As a step-off from the reference case, partial capture of CO_2 is evaluated. For example, 90 percent capture of CO_2 from half of the flue gas would result in 45 percent capture.

The reference cases are based on implementation of CCS in 2025 in West Java and 2027 in South Sumatra, respectively (i.e., five years after the commissioning of the power plants). The

[1] Based on its commitments to the Kyoto Protocol and other initiatives relating to addressing climate change.
[2] EOR is an established technique for enhancing the production of oil from an aging oil well by injecting dense phase CO_2 to improve the mobility of oil deposits in porous rock and to displace oil towards a production well.

CCS operation would then run for 20 years, being the remainder of the power plant design life of 25 years. The economic assessment reference case is based on CCS being built with no delay, for comparability with other technologies. Longer CCS implementation delays are also assessed.

KEY FINDINGS OF THE STUDY

1. A technically feasible process for CO_2 capture has been identified.

The retrofitted capture of CO_2 from power plant flue gas requires as little impact as possible on the existing power plant. However, retrofitting limits the choice of CO_2 capture process to chemical absorption from the flue gas at atmospheric pressure. The use of monoethanolamine (MEA) as the chemical absorption reagent is a commercially proven process that is usually considered for bulk CO_2 removal in CCS applications.

The MEA process requires a large amount of low-grade heat. This is the primary energy penalty associated with CO_2 capture. That heat is supplied as low pressure steam extracted from the power plant steam cycle, which reduces the amount of electricity generated by the host power plant.

Another requirement for the MEA process is for the feed gas to be clean to avoid degrading the MEA solvent. Additional acid gas removal equipment must therefore accompany the MEA stripping process. Hence, a side effect of CO_2 capture would be a major reduction in the environmental emissions of sulphur dioxide (SO_2), oxides of nitrogen (NOx) and particulates from coal use.

2. Both plants can be considered as capture-ready as long as enough space is reserved and the plant design recognizes future CO_2 capture.

The additional requirements to make the coal power plants CCS-Ready would have a significant impact on the power plant site layout, which will require the power plant to have sufficient extra land allocated for future installation of CO_2 capture equipment; however, there would be very little impact on the capital cost of the host power plant prior to implementation of CO_2 capture. No major changes to the host power plant would be required for post-combustion capture. However, recognition at the detailed equipment design stage of the likelihood for future retrofitting of CO_2 capture may give rise to exercising options and developing innovations to ease the later retrofitting of CO_2 capture. Other than potential additional land acquisition, the up-front cost of making a power plant CCS-ready would be minor and within the power plant budgeting contingency. Substantial costs would not be incurred until CCS is implemented.

3.	**CO_2 capture processes would incur a considerable energy penalty resulting in a lower net capacity of the plant.**

The reduction in power output is estimated at 27.5 percent and 30.8 percent for the large West Java plant and the smaller South Sumatra plant, respectively; at 90 percent capture. This energy penalty is especially challenging in the current power sector environment where generation expansion is a priority.

4.	**CCS will require sizeable investments, especially on the capture side, raising the base plant investment cost by more than 50 percent.**

Implementation of 90 percent CO_2 capture in the West Java power plant would have an estimated incremental capital investment of about US$1.68 billion and annual operating cost of about US$182 million. For the South Sumatra power plant, the incremental capital cost would be US$743 million with an annual operating cost of US$65 million.

5.	**Sufficient storage capacity in depleted gas fields has been identified in West Java for CO_2 from the West Java plant and in South Sumatra for CO_2 from the local plant.**

After a gas well has ceased production it may become available for the storage of CO_2. A survey of the potential storage capacity of large depleted and depleting gas fields in South Sumatra and West Java is reported in Table ES 1.

Table ES 1 CO_2 storage capacity in depleted and depleting gas fields (millions of tonnes)[3]

Location	Number of gas fields	CO_2 storage capacity	Storage required
		Millions of tonnes of CO_2	
On-shore South Sumatra	45	537	74
On-shore West Java	22	171	218
Off-shore West Java	29	224	218

The CO_2 captured from the 600MW South Sumatra power plant at 90 percent capture over 20 years would be a total of 74 million tonnes. That would occupy 14 percent of the gas field storage capacity in South Sumatra. The remaining gas field storage capacity in South Sumatra would only be sufficient to accommodate CO_2 from a further 3,750 MW of similar nominal power generation capacity.

The CO_2 captured from the 2000 MW West Java power plant at 90 percent capture over 20 years would be a total of 218 million tonnes of CO_2. There is just sufficient off-shore gas field storage in West Java to accommodate all of that CO_2.

[3] Tonne (t), also known as metric ton, is a unit of mass equal to 1000 kilograms (equivalent to approximately 2,204.6 pounds, 1.10 tons (US), or 0.984 tons (imperial).

6.	Storage capacity for CO_2 in deep aquifers is large but uncertain.

Liquid CO_2 can, in principle, be stored in any deep porous rock that is overlain by impervious rock. At underground conditions it would become a supercritical fluid.[4] Deep aquifer storage potential is assessed at 10 times gas field storage in South Sumatra and West Java. However, permanent storage of CO_2 would be less certain and more costly.

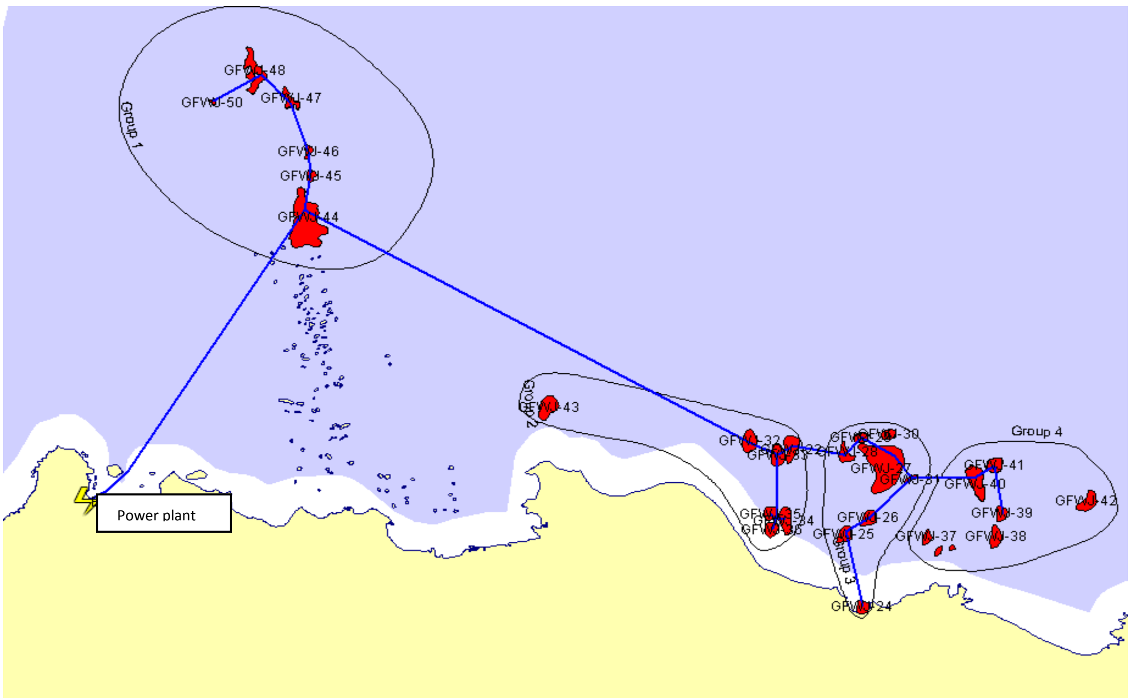
7.	Eventually CCS would become constrained by available CO_2 storage capacity.

In the long term, mandatory application of CCS to all projected new coal-fired power plants in South Sumatra would result in on-shore geological storage of CO_2 in gas fields becoming full by about 2050 and extension of storage into deep aquifers becoming capacity-constrained by 2100.

8.	Pipeline networks have been devised to transport CO_2 from the power plants to storage sites.

Figure ES 1 shows a scheme for delivering CO_2 from the West Java power plant to depleted off-shore gas fields north of West Java, which are nearer and have more capacity than on-shore fields.

Figure ES 1 Transport of CO_2 to off-shore gas fields in West Java

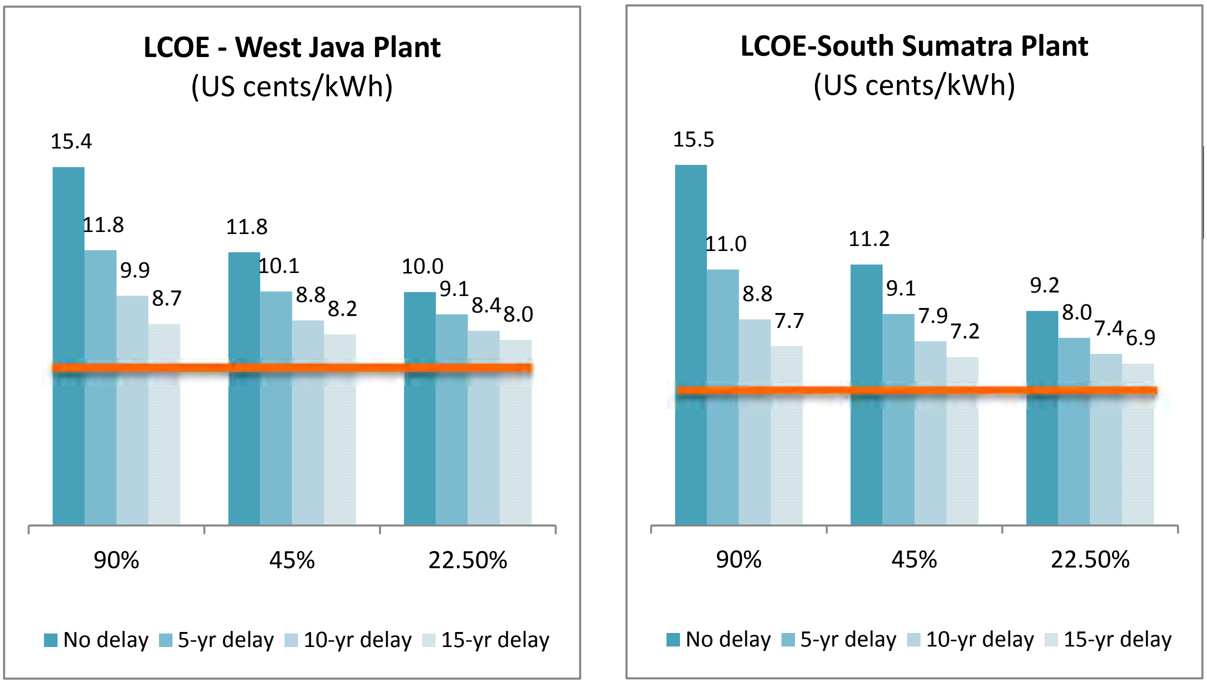


The South Sumatra power plant is located within the oil and gas producing region of South Sumatra, so pipelines would be much shorter and would be on-shore.

[4] CO_2 above 73.9 bar pressure and above 31.1°C is a supercritical fluid with properties similar to a liquid but without surface tension effects, so that it behaves like a gas. Supercritical CO_2 is a benign solvent.

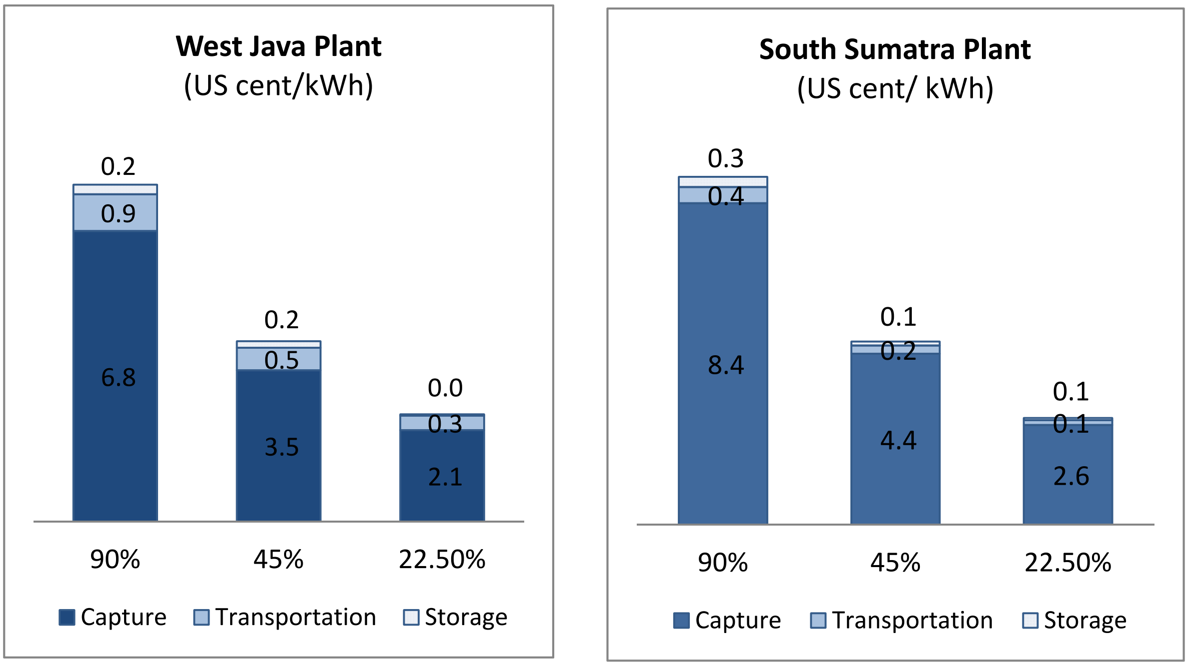
9.	**At 90 percent capture, the levelized cost of electricity (LCOE) is estimated at 15.4 and 15.5 US cents per kilowatt hour (kWh), translating to a net incremental cost of CCS at 7.9 and 9.1 US cents per kWh for the West Java and South Sumatra power plants, respectively (Figure ES 2).**

Figure ES 2 Effect of implementation delay on LCOE



10.	**CO_2 capture accounts for more than 80 percent of the total incremental cost of CCS (Figure ES 3).**

Figure ES 3 Effect of extent of CO_2 capture on electricity cost



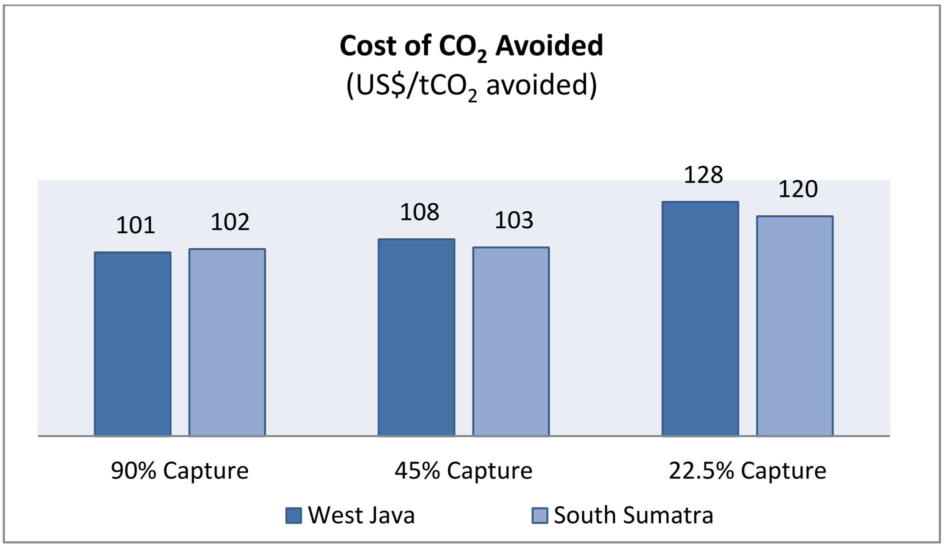
11.	**On an LCOE basis, coal-fired plants with CCS are comparable with plants of similar scale and level of CO_2 emissions.**

At 90 percent capture, the LCOE of the South Sumatra power plant, at 15.5 US cents per kWh, is comparable to the newly-set ceiling price for large-scale geothermal in 2022 at 14.6 US cents per kWh. At 45 percent capture, the LCOE of the South Sumatra power plant, at 11.2 US cents per kWh, is competitive with a base-load combined-cycle gas turbine (CCGT) plant with liquefied natural gas (LNG) at an estimated 12 US cents per kWh.[5]

12.	**The cost of CCS is equivalent to about US$100/tonne of CO_2 emission avoided (Figure ES 4).**

The cost of net CO_2 emission avoided is calculated on the basis of the same quantity of net electricity delivered to the transmission grid with and without CCS.

Figure ES 4 Effect of reduced capture on CCS cost



13.	**Lower capture percentage and/or delayed implementation will reduce the incremental cost of CCS, albeit at the expense of higher CO_2 emissions.**

Reducing the capture percentage from 90 to 45 percent, or delaying CCS implementation by five years from plant commissioning, would halve the net incremental cost of CCS.

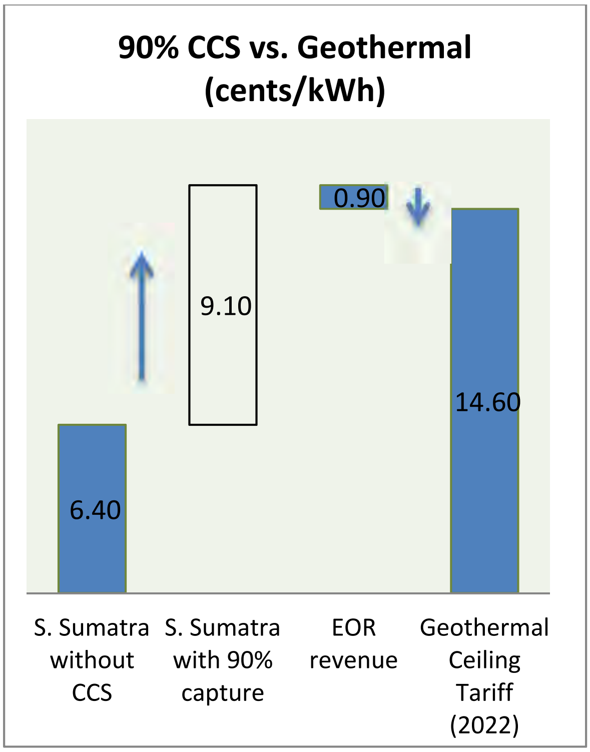
14.	**Enhanced Oil Recovery is an attractive cost-offsetting mechanism (Figure ES 5).**

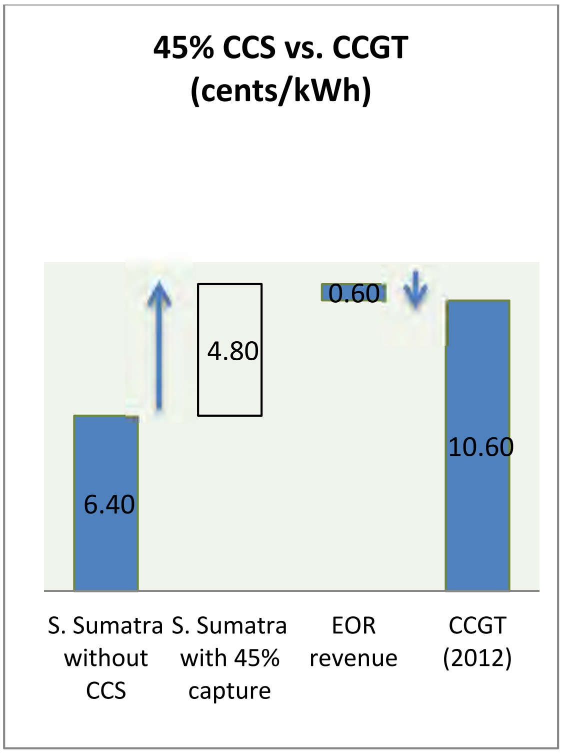
A small amount of EOR revenue (an equivalent of under US$10 per t$CO_2$ at the gate of the plant) would be required to bring: (a) the LCOE of the South Sumatra plant with 90 percent

[5] Assuming LNG price at US$16/MMBtu (Millions of British Thermal Units), based on the latest Indonesian Electricity Supply Business Plan, RUPTL (2015-2024), with CCGT plant efficiency at 54 percent.

CO_2 capture down below the ceiling price for geothermal; and (b) the LCOE with 45 percent CO_2 capture down below PLN's average cost of base load CCGT.

Figure ES 5 Comparison of Coal +CCS with low carbon technologies





15. The demand for CO_2 for EOR in South Sumatra would be insufficient to accommodate CO_2 from West Java (Table ES 2).

There would be sufficient EOR demand in South Sumatra, which is all on-shore, to accommodate the CO_2 captured from the South Sumatra power plant, as well as low cost CO_2 sources, but not enough to accommodate CO_2 from West Java.

Table ES 2 Potential for EOR to accommodate CO_2 from CCS

	Millions of tonnes of CO_2
Demand for CO_2 for EOR in South Sumatra	243
Supply from low cost CO_2 sources over 25 years	162
Remaining demand	81
South Sumatra plant at 90 percent capture for 20 years	74
Remaining demand	7
South Sumatra plant at 90 percent capture for 20 years	218

16.	**The South Sumatra power plant is well placed to take advantage of EOR opportunities is South Sumatra, whereas the West Java power plant is not.**

EOR provides revenues, transfers the costs and liabilities associated with CO_2 storage, and demonstrates CO_2 injection technology. However, the ability for the host plants to take advantage of EOR opportunities is uncertain due to:

- Limited demand and competing supplies of CO_2 for EOR;
- Peak demand for CO_2 for EOR at an oil field is for a short period;
- Uncertain willingness-to-pay from EOR operators due to oil price fluctuations; and
- The cost of CO_2 delivery from sources that are a long distances from the EOR site.

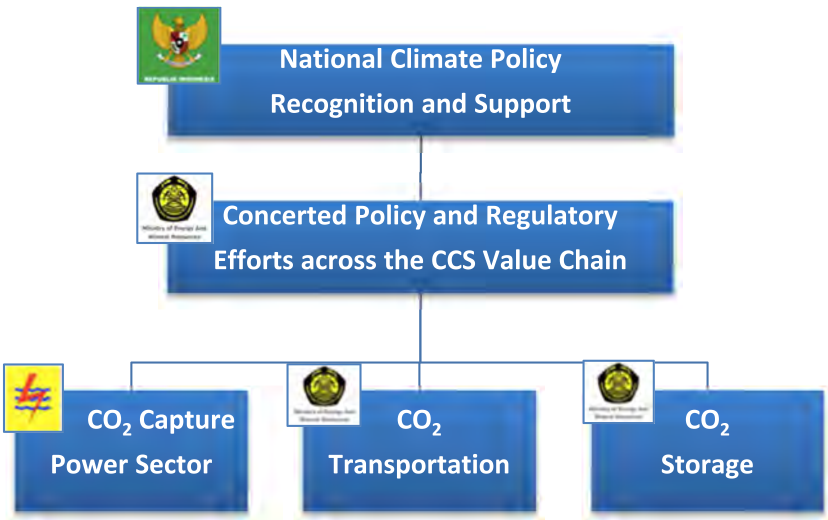
17.	**Policy recognition and institutional support is a key barrier for CCS implementation in Indonesia.**

Institutional readiness for CCS in the power sector requires national climate policy support and concerted efforts across CO_2 capture, transportation and storage (Figure ES 6). Each process requires the facilitation of appropriate institutional, legal and regulatory frameworks to govern the structure, operations, ownership, management and monitoring of the process.

18.	**All of the above institutional support mechanisms need to be established.**

For CCS to contribute to Indonesia's CO_2 reduction targets in 10 years' time, planned power plants need to include CCS-readiness provisions. To define those CCS-ready provisions, the regulatory environment needs to be in place. To build the regulatory environment, the policy framework needs to be established. Hence, there is urgency for institutional support mechanisms to be established.

Figure ES 6 CCS Development Framework



RECOMMENDATIONS

Creating an enabling policy and regulatory environment

- National climate policy to recognize CCS in the power sector as a means of CO_2 emission reduction;
- Endorsement of the CCS Road Map, which included the power sector at the national level; and
- Concerted efforts along the CCS value chain: CO_2 capture, transportation and storage.

Bridging the technical and financial viability gap

- Consider adding CCS-Readiness Provisions (such as space provisions and design modifications) in the Power Purchase Agreements (PPAs) of future Independent Power Producer power plants;
- Provide policy incentives for future CCS implementation;
- GoI to initiate CCS pilot and demonstration activities for the power sector; and
- Power sector inclusion in the CCS Road Map.

Awareness and capacity building

Develop an Indonesian Canter of Excellence in CCS technology that is purpose tasked to:

- Build technical and economic assessment capability;
- Develop technologies to suit Indonesian conditions;
- Run workshops to encourage wide understanding of potential and limitations of CCS; and
- Encourage public acceptance of CCS technologies.

1. INTRODUCTION

1.1 Study objectives

This Analytical and Advisory Assistance (AAA) project is supporting institutional capacity building for *PT Perusahaan Listrik Negara (Persero)*, (PLN), which is the sole national electric utility in Indonesia, and the Government of Indonesia in developing Carbon Capture and Storage awareness and expertise. In the longer term, this assistance will support Indonesia in reducing carbon dioxide emissions from its fossil fuel power generation sector and will contribute significantly to putting the country's energy sector on a sustainable development path while improving energy security. The focus is to assess the implications of deployment of CCS to increase confidence that introducing CCS-readiness to future fossil power plants will ensure that subsequent CCS retrofit is practicable.

Another objective is to examine whether the supply of CO_2 for enhanced oil recovery is a potential means of lowering CCS costs and potentially aiding project financial feasibility.

Specifically, this project has three major objectives:

- To assist PLN with economic, technical, operational and environmental analysis of the implications of CCS-readiness for two selected coal-power plants;
- To explore the enhanced oil recovery market and other geological CO_2 storage capacity to assess their adequacy for accommodating captured CO_2; and
- To strengthen the stakeholders' CCS capacity by disseminating study findings through workshops and training.

1.2 Definition of CCS-Readiness

CCS-readiness is a planning tool used to provide a structured means of assessing a power plant design in order to ensure that there are no insurmountable barriers to subsequent retrofitting of the complete CCS train at some time in the future when CCS implementation may be required due to changed economic or regulatory circumstances. CCS-R involves capture-readiness, transport-readiness and storage-readiness to ensure that any potential barriers to successful implementation of a complete CCS scheme are identified and resolved at an early stage.

For the power plant component, capture-readiness requires a technically and economically feasible CO_2 capture outline design to be established. The power plant layout should allocate space and connection facilities for the possibility of future addition of CO_2 capture equipment.

For transport-readiness, a technically and economically feasible transport method needs to be established. A practical transport route with accessible rights-of-way between the power plant location and the storage location should be identified.

For storage-readiness one or more storage sites need to be identified that are technically capable of, and commercially accessible for, timely geological storage of the large volumes of captured CO_2 for the projected lifetime of the CCS scheme. Adequate capacity, injectivity (i.e., adequate porosity to permit a high rate of injection of CO_2 without fracturing the formation), and CO_2 storage integrity should be shown to exist at the storage site. Any potentially conflicting land use issues should be identified.

For all CCS stages, the requirements for environmental, safety and other approvals need to be identified. Public awareness and engagement activities need to be considered. The CCS-readiness status should be regularly reviewed, improved and documented over time. The United Kingdom (UK) has developed a set of CCS-R guidelines that are included, for reference, in Annex 1.

1.3 Structure of the study

In the Background chapter, the energy scene in Indonesia is described, identifying the need for rapid expansion of electricity generation infrastructure and the energy resources available to meet that need. Indonesia's commitment to addressing CO_2 emissions are described, which highlight a role for CCS. The issue of the potential impact of exploitation of the Natuna gas field on Indonesia's CO_2 emissions inventory is also introduced.

In the Study Basis chapter, the selection of candidate lignite-fired coal power plants in West Java and South Sumatra for CCS-R assessment is explained and the key features of those nominal host power plants are listed. Scenarios that would give rise to the need to implement CCS are discussed and the rationale for the assessment scenarios is set out. A comparison with the alternative use of geothermal or natural gas-fired power generation as a means of reducing CO_2 emissions is quantified.

In the Capture Study chapter, the technology for post-combustion capture of CO_2 with conventional MEA is described and assessed. Processes for preconditioning of flue gas are discussed and evaluated. Processes for conditioning and compression of the captured CO_2 are also discussed. Alternative CO_2 capture processes are investigated. Operating cost parameters and capital cost data for elements of the CO_2 capture process are listed.

The Transportation Study chapter comprises two parts: transmission and distribution. Transmission relates to bulk pipelining of CO_2 from the power plants to distribution hubs local to the CO_2 storage locations. Distribution relates to the delivery of CO_2 from the distribution hubs to the CO_2 injection points. CO_2 transportation cost data are determined.

In the Storage Study chapter a review of opportunities for geological storage of CO_2 is carried out. The potential storage of CO_2 in depleted gas fields in West Java and South Sumatra is assessed. An outline discussion of the scope for CO_2 storage in deep saline aquifers is presented. Estimates of CO_2 injection costs are also presented.

In the EOR Market Review chapter, the potential demand for CO_2 for EOR is assessed and compared with the scope for that market to be satisfied with low-cost by-product CO_2 from sources other than CCS.

The Incremental Cost Analysis chapter includes an assessment of the cost of the coal power plants with complete CCS trains in terms of levelized cost of electricity and US$/tonne of CO_2 captured and emission avoided, based on data for elements of the CCS process train determined in this study. The impacts of timing of CCS implementation and partial reduction of CO_2 capture fraction are also considered.

In the Institutional Readiness chapter, the need for policy mechanisms and supportive regulatory frameworks for the CCS value chain are identified and discussed. Issues of CCS-readiness with respect to Power Purchase Agreements with Independent Power Producers (IPPs) to build coal-fired power plants in Indonesia are also discussed. Recommendations for PLN and the GoI are made.

1.4 Worldwide CCS projects

Sixteen of the 22 large-scale CCS projects worldwide that are in operation, or under construction in 2014 use, or will use, the captured CO_2 primarily for EOR. However, only three of those are coal-fired power generation projects; the others are natural gas processing plants and industrial processes. EOR with CO_2 can make CCS demonstration projects economically viable. This approach, known as Carbon Capture Utilization and Storage (CCUS), is most evident in regions of mature oil extraction such as North America, the Middle East and China, where market opportunities to utilize CO_2 as a commodity with value are strongest (GCCSI, 2014).

The other six active CCS projects involve dedicated geological storage of CO_2 without EOR revenue. All of these projects source CO_2 from natural gas processing operations or industrial operations where the production of a pure CO_2 stream is a necessary part of that industrial process, so the marginal cost and energy penalty of CO_2 capture are not great.

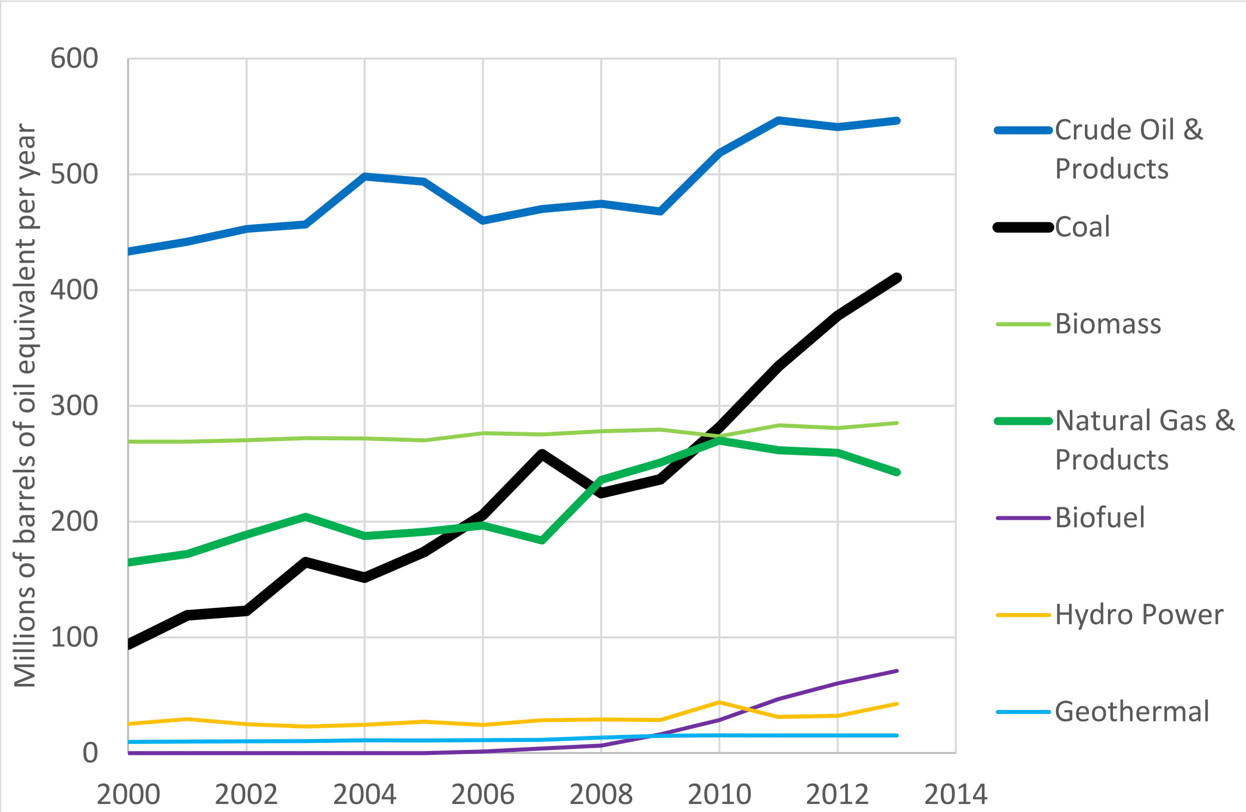
A further 33 large-scale CCS projects are at an advanced stage of concept planning or at an earlier stage of evaluation. Of these 33 potential CCS projects, only four (in China, South Korea, Scotland and the Netherlands) involve demonstration of post-combustion capture of CO_2 from a power generation unsupported by EOR. All of those four projects anticipate operation at a demonstration scale of about one million tonnes of CO_2 per year by 2020 (GCCSI 2014).

2 BACKGROUND

2.1 Domestic energy growth

Indonesia's growing economy is pushing up domestic energy consumption. Indonesia has sustained an economic growth of about 6 percent per annum over the past five to eight years (IMF, 2014), and this has been increasing the total primary energy consumption by an average of about 5 percent per annum over the same period (BP, 2014). Primary energy consumption in 2013 was 43 percent higher than a decade earlier. The national energy mix of consumption in 2013 was dominated by oil at 43 percent, coal at 33 percent and natural gas at 19 percent, with non-fossil fuels at only 4 percent (excluding biomass and biofuel). Figure 2-1 shows the progression of primary energy consumption in Indonesia up to 2013 (MEMR, 2014).

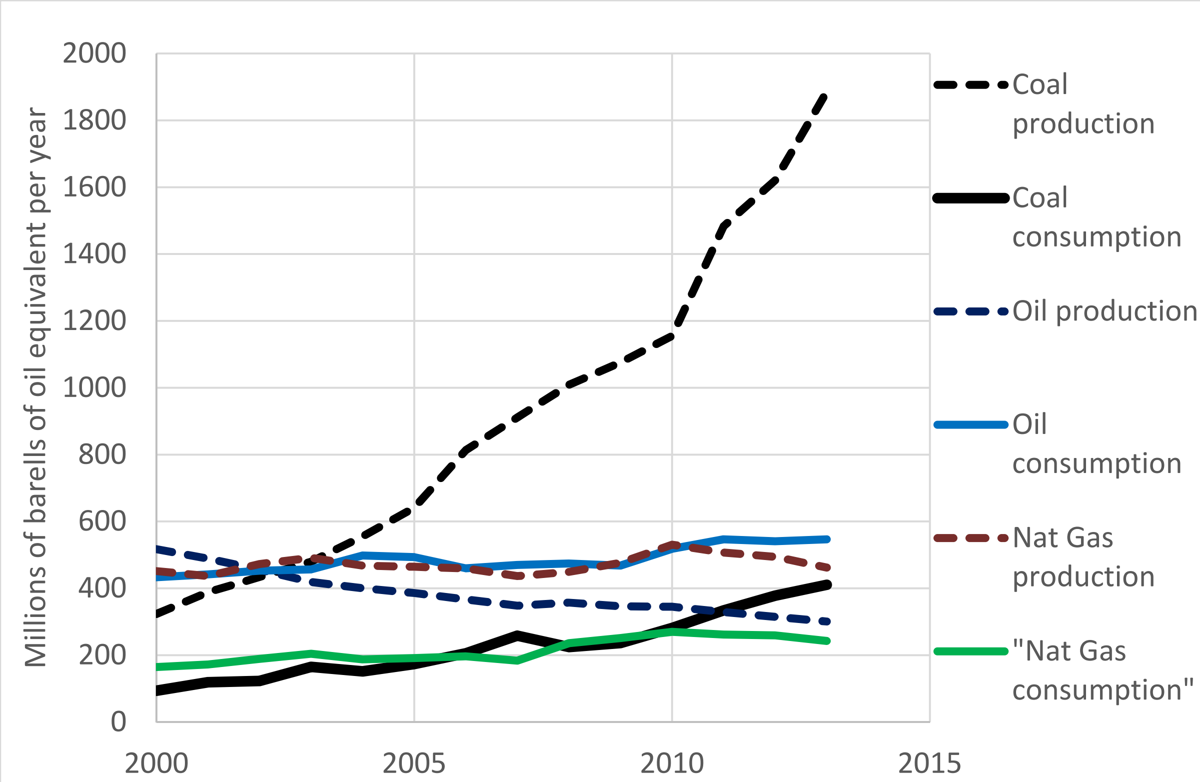
Figure 2-1 Primary energy consumption in Indonesia up to 2013



Over the decade from 2003 to 2013, coal has gained more importance in Indonesia's mix of primary energy resources for domestic consumption. Coal use has increased by 150 percent from about 165 million barrels of oil equivalent (MMBOE)[6] (~39 million tonnes per year) to about 411 MMBOE (~98 million tonnes per year). In comparison, oil and gas consumption as primary energy resources have both increased by about 20 percent: oil from about 456 MMBOE to about 546 MMBOE, and domestic natural gas consumption from about 204 MMBOE (1.31 trillion standard cubic feet [Tcf]) to about 243 MMBOE (1.56 Tcf), after a peak in 2010 (Figure 2-2).

[6] BOE is Barrel of Oil Equivalent; MMBOE is million barrels of oil equivalent.

Figure 2-2 Fossil fuel production and consumption in Indonesia



In terms of primary energy production, the tonnage of coal mined has nearly quadrupled between 2003 and 2013 from 104 million tonnes to 407 million tonnes. More than three quarters of coal produced was exported to the international market in 2013. Over the same period, annual production of natural gas ranged between 2.8 Tcf and 3.4 Tcf, and has decreased within this range in the last three years. Nearly half of the gas production is exported as LNG to international buyers. Oil production has declined over the same period, from 1148 thousand barrels per day in 2003 to 824 thousand barrels per day in 2013. About 40 percent of oil used in Indonesia was net imported in 2013.

2.2 Domestic power generation mix

The domestic power generation mix is dominated by fossil fuels. As shown in Figure 2-2, the contribution from the non-fossil sources of hydro and geothermal is small. PLN's electricity production in 2013 was 164 terawatt hours (TWh) -- comprising 147 TWh produced from fossils, 13 TWh from hydro power and 4 TWh from geothermal -- while the contribution from other renewables, such as wind power, was a very small 0.005 TWh. Thus, non-fossil electricity only contributed 10.7 percent of the total production.

During 2013, PLN also purchased an additional 52 TWh of electricity from IPPs; 69 percent from large coal-fired power plants, 13 percent from smaller gas-fired plants, 10 percent from geothermal plants and 8 percent from hydropower and other renewables plants. With IPPs in the total power generation mix, the contribution of renewables was about 12 percent in 2013.

2.3 Indonesia's electricity outlook

The electricity demand in Indonesia is primarily driven by the economy and population growth, at an average of 6 percent and 1.2 percent per year, respectively, and also increasing urbanization. In anticipation of the rising demand, and also as mandated by the prevailing law and regulations, PLN, Indonesia's only state-owned utility responsible for most of the national power generation capacity, prepares a 10-year power capacity development plan referred to as the *Electricity Supply Business Plan* (RUPTL, 2015). According to the RUPTL 2015-2024, electricity consumption of PLN's consumers throughout the country will increase by 8.42 percent per year, going from 219 TWh in 2015 to 464 TWh in 2024. To meet this growing demand, in RUPTL PLN lists all power projects as well as transmission and substation projects over a period of 10 years.

Presidential Decree No. 71/2006 launched the First Phase of the Fast Track Program (FTP I) with the goal of building 10 GW of additional capacity. The decree specifically required PLN to build *coal-fired plants* for two major reasons: firstly, oil fuel costs more than coal fuel (nine times more at the peak in 2008); and secondly, there is an abundance of coal reserves in Indonesia. Identified coal reserves in 2013 totaled 28 billion tonnes of sub-bituminous coal and lignite (BP, 2014). Potential coal resource totaled about 120 billion tonnes in 2013, with 24 measured, 36 inferred and 33 hypothetical (WEC, 2013). The majority of power projects under the 10 GW of coal power projects selected in 2006 for a fast track capacity development program have been completed.

In 2010, Presidential Decree No. 04/2010 launched the Second Phase of the Fast Track Program (FTP II) with the goal of procuring an additional 9.5 GW of renewable energy, gas and coal-fired plant capacity. The 9.5 GW of power projects in FTP II were selected from the list of potential projects originally identified by PLN in RUPTL-2010. By putting the projects into FTP II, they are now recognized as the projects that will get government support in their implementation.

In FTP I, the project list was fixed by Presidential Decree. In FTP II, the project list was decided by a ministerial regulation of the Minister of Energy and Mineral Resources (MEMR). In the original FTP II of 2010, coal was expected to account only for 33 percent of the total additional capacity, natural gas for 15 percent, and the rest being renewable energy, which is geothermal and hydro power. In contrast to FTP I, FTP II emphasizes renewable energy and seeks to contribute towards addressing global warming challenges.

However, the project list of FTP II was amended by MEMR in August 2013 by the addition of a further 9.2 GW of coal-fired power projects to the list (MEMR, 2013). The additional 9.2 GW coal power projects were selected from the list of potential projects in RUPTL in order to provide sufficient capacity to meet the future projected demand in 2022. Again, the purpose of adding the 9.2 GW coal power projects is to recognize them as the projects that will be granted government support. This amendment indicates that the GoI would provide political support as well as commercial comfort to the implementation of large-scale coal power plants to secure future electricity supply. Altogether, 22.4 GW of new coal-fired capacity is planned to be built by 2022.

This extensive power plant building program is required to meet the expected demand growth, while maintaining an adequate reserve margin. An important finding of this study is that the installation of CCS would significantly reduce the net output from a power plant relative to its nameplate capacity. However, assessment of the expansion of the power plant building program that would be required to accommodate the mandatory implementation of CCS on all new power plants is beyond the scope of this study.

2.4 Projected CO_2 emissions

The increased coal-based generation contributes to increased CO_2 emissions. While Indonesia has considerable greenhouse gas emissions from forestry and land use change, CO_2 emissions from fossil fuel use are rising. In 2013, 523 million tonnes of CO_2 were emitted from the consumption of fossil fuels, ranking Indonesia as the ninth largest CO_2 emitting country in the world -- though this is still much less than China, USA, Japan and India (BP, 2014). The power sector alone would emit 201 million tonnes of CO_2 in 2015, and is projected to emit 383 million tonnes by 2024 in line with the projected power generation mix in Indonesia's power sector to 2024 (RUPTL, 2015). By the year 2024, coal will account for 87 percent of the power sector emissions (RUPTL, 2015). CO_2 emissions from the entire country are expected to reach 1,150 million tonnes of CO_2 per year by 2025 unless the government takes action to reduce emissions.

2.5 CO_2 emission reduction obligations

CCS provides an opportunity for the government to meet both its energy needs and its non-binding target to reduce CO_2 emissions by 26 percent by 2020. Indonesia signed the Kyoto Protocol in 1998 and ratified it in 2004 through Law No. 17/2004. In 2011, the government issued Presidential Decree No. 61 of 2011 regarding the National Action Plan on Greenhouse Gas (GHG) Reduction (RAN-GRK) of which the objective is "to be used as guidance to various institutions in carrying out a coordinated and integrated effort to tackle climate change" (Survanti, 2009).

GHG emission reduction through CCS in the power sector is not part of the RAN-GRK. The largest cut of emissions in RAN-GRK is from the forestry and land use sectors, with only a very modest CO_2 reduction target for the power sector through small hydropower and geothermal power plant developments.

Presidential Decree No. 61 is supported by another Presidential Decree, No. 71 of 2011, regarding the National GHG Inventory. The GoI was recognized as an important country for global climate policy discussion as it hosted the thirteenth Conference of the Parties of the United Nations Framework Convention on Climate Change (UNFCCC) meeting in Bali. In 2008, Indonesia unilaterally pledged by 2020 to cut energy sector emissions by 26 percent, and by up to 41 percent if supported by the international community.

According to the International Energy Agency (IEA), CCS is part of the global lowest-cost greenhouse gas (GHG) mitigation portfolio. Without CCS contributing a fifth of the necessary emission reductions, the global cost of reducing GHG emissions would rise by 70 percent.

Simulations by LEMIGAS[7] and partners indicate that CCS could reduce CO_2 emissions by 13.4 percent under different National Energy Policy Objective scenarios, as set by the Presidential Decree No. 5 of 2006.

Further discussion of progress in Indonesia towards these targets is outside the scope of this study.

2.6 Need for CCS

One way to meet the GoI's goal of improved energy supply and security, while also reducing CO_2 emissions, is for future coal-fired power plants to include CCS. As a government-owned utility contributing the most to national electricity capacity, PLN has an important role to play in leading the way in Indonesia. Investigating the implications of having CCS-ready plants is an important first step. CCS-ready plants could reduce the costs of retrofitting coal plants for CO_2 capture during the 25-year life span of a typical coal plant with likely extension for another 20 years. Investment decisions made in today's uncertain environment need to consider the full range of future conditions under which the plant may operate. Retrofitting CCS-ready coal plants with CO_2 capture equipment any time during their life could be significantly less expensive than attempting to retrofit non-capture-ready coal plants. Thus, designing plants to be CCS-ready could save PLN and IPPs significant costs if the regulatory and/or economic environment changes.

2.7 CO_2 from Natuna gas field

The production of natural gas from the East Natuna gas field could affect CO_2 storage in South Sumatra or West Java. The East Natuna gas field in the South China Sea has a CO_2 content of 71 percent, which has to be separated and removed to produce a saleable natural gas product. That gas processing operation would produce seven volumes of CO_2 for each three volumes of natural gas product. The planned peak rate of gas production from the Natuna field is about 4 billion standard cubic feet per day after processing, which is expected to commence in 2024 (Azwar, 2013), (OGI, 2014). That production rate would yield 190 million tonnes per year of CO_2, which is about the same as would be produced by CCS from 35 GW of coal-fired power plant capacity with 90 percent CO_2 capture. The Natuna gas field may be exploited at that rate for 20 years from about 2025, producing 3,800 million tonnes of CO_2 before gas production subsequently declines.

If a driver for the implementation of CCS eventuates, that driver could apply equally to CO_2 stripped from Natuna gas, which might need to use CO_2 storage capacity in South Sumatra or West Java for CO_2 from Natuna, if storage elsewhere is inadequate. Since the cost of stripping CO_2 from Natuna gas will be borne by the gas producers, only the cost of CO_2 transport from Natuna would compete with the cost of capture and transport from coal-fired power plants. Therefore, there is a risk that CO_2 from Natuna could reduce CO_2 storage capacity available for CCS. However, the possibility of CO_2 from Natuna being stored in South Sumatra or West Java is not included in the analysis in this report.

[7] *Lembaga Minyakdan Gas Bumi,* which is the Indonesian research and development center for oil and gas technology.

3 STUDY BASIS

The scope of this study is to assess the feasibility of building new conventional coal-fired power plants in the near future in such a way that they could be retrofitted with CO_2 capture some years after their initial commissioning; i.e. to be built as "CO_2 capture ready". Accordingly, retrofitting CO_2 capture to existing plants or plants that are already designed is outside the scope of this study. Likewise the selection of technology for future power plants that might be required to integrate CO_2 capture in their original design are also outside the scope of this study.

3.1 Plant selection criteria

A portfolio of existing and proposed power plants in the RUPTL (2013-22) was compared against the following set of criteria:

- *Plant efficiency and associated capture costs*. To minimize the impact of CO_2 capture on overall cycle efficiency, the power plants targeted for CCS should be large units (>600 MW). The most suitable candidates under this criterion are a few coal-fired supercritical or ultra-supercritical coal power plants to be constructed in the timeframe of 2018-22.[8]. The sizes and efficiencies of all existing thermal plants, as well as the proposed gas-fired units are sub-optimal according to this criterion.
- *Adequacy of space.* Space availability around existing coal- and gas-fired plants in urban demand centers is too limited to allow for subsequent CO_2 capture and compression equipment installation.
- *Construction timing.* Previous studies have indicated that it is appropriate to allow for CCS-R modifications to be included at the initial design stage, which favors the choice of plants not expected to begin operations until 2018 or later.
- *Demonstration potential.* To ensure the future applicability of the study findings, the selected power plant(s) should be representative of Indonesia's generation mix. A review of RUPTL suggested that with the uncertainties around natural gas supply, the use of gas in Indonesia's generation mix will be declining in the period 2013-22. A few new gas-fired power plants will be coming online only when the GoI has allocated new gas supplies for electricity generation to those newly planned gas-fired power plants, while outputs from the existing plants are expected to decline due to the aging facilities.
- *Availability of CO_2 storage in the region.* The detailed assessments of CO_2 storage and the potential of EOR are carried out in this study. The availability of depleted oil fields in the region needs to be confirmed before the site is selected. This is especially relevant for sites located in Java, where availability of depleted oil fields is apparently minor.

In light of the above considerations, PLN and the World Bank team reviewed the existing and planned thermal power plants under PLN's official Power Development Plan (RUPTL, 2015),

[8] The engineering design of power plants with commissioning dates earlier than 2018 are likely to have already been fixed.

came up with a shortlist of power plants, and then decided on two power plants to be built by IPPs as the basis for the CCS-R study.

3.2 Selected plants

Two plants – one located in West Java and the other in South Sumatra -- were selected as a nominal basis for the study. Although specific plants were selected and plant data was derived from prefeasibility studies of those plants, in order to be as realistic as possible, the plants are taken as generic examples. Some plant-specific data was modified in order to provide consistency in the host plant specifications so that assessment of the impact of adding CO_2 capture was carried out on a consistent basis.

The larger plant, on the north coast of West Java, comprises 2 x 1000MWe (megawatts of electricity) ultra-supercritical (USC) units.[9] Under full operational conditions, with 90 percent CO_2 capture operational, the initially-estimated quantity of captured CO_2 from both units combined would be 10.92 million tonnes CO_2/year. The smaller plant in South Sumatra would be a 1 x 600MWe unit. For the purpose of this study, the more thermally efficient supercritical plant design has been assumed. The total annual quantity of CO_2 captured at a 90 percent CO_2 capture rate would be 3.68 million tonnes of CO_2 per year. Therefore, the maximum total quantity of CO_2 for which storage is required would be 14.6 million tonnes per year for 2600 MWe of nominal electricity generation capacity.

The coastal 2000MWe host power plant in West Java will use a high-sulphur lignite and will include seawater scrubbing of the flue gas to reduce the SO_2 content to meet the environmental criterion of 750 milligrams (mg) SO_2 per Nm^3 [10]. The smaller 600MWe inland host power plant in South Sumatra will use lower-sulphur lignite with high moisture content, but will not have flue gas desulfurization. The reference host power plant design parameters are derived from prefeasibility studies and discussion with PLN. The key parameters used for this study are listed in Table 3-1.

[9] In this context the terms ultrasupercritical and supercritical refer to the steam conditions at the inlet to the very high pressure (VHP) steam turbine, which is a key parameter affecting the thermodynamic efficiency of the power generation cycle. The critical point of steam is at a pressure of 221.2 bar and a temperature of 374.15°C. When the top pressure in the steam cycle is above 221.2 bar it is termed supercritical. Supercritical power plants typically have VHP inlet conditions of about 250 bar and 550°C. Ultrasupercritical power plants, which require more expensive materials of construction, typically have VHP inlet temperature in excess of 600°C.

[10] Nm^3 – normal cubic metres at 1bar pressure and at 0°C.

Table 3-1 Key parameters for the reference plants for the CO_2 Capture-Ready Study

Location	North West Java	South Sumatra
Installed Capacity	2 x 1000 MW	1 x 600 MW
Technology	Ultra supercritical	Supercritical
Commissioning year	2020	2022
Source of coal	Kalimantan	Mine mouth
Capacity Factor	80%	80%
Boiler Efficiency (HHV)[1]	83.3%	76.3%
Turbine Efficiency	46.2%	44.0%
Coal quality		
Gross Calorific Value (HHV)	3,880 kcal/kg[2] (as received)	2600 kcal/kg (as received)
Total moisture content	Average 35%	Average 54%
Ash content	Average 5.0%	Average 6.5%
Sulfur content (dry ash free)	Average 1.8%	Average 0.86%
Annual CO_2 emissions	12.13 million tCO_2[3]	4.09 million tCO_2
Desulfurization technology	Seawater scrubber	None
Power plant efficiency	$42.5\%_{lhv}$[1] $38.5\%_{hhv}$[1]	$40.8\%_{lhv}$ $34.4\%_{hhv}$

Notes: [1] HHV (or hhv) denotes Higher Heating Value, which is also known as Gross Calorific Value, and is a measure of heat of combustion for fuels. "lhv" denotes Lower Heating Value, which is also known as Net Calorific Value; [2] kcal/kg means kilocalories per kilogram; [3] tCO_2 means tonnes of carbon dioxide.

3.3 Capture Scenarios

To be most cost effective, the CO_2 capture equipment would be designed to capture 90 percent of the CO_2 from a flue gas stream, as discussed in Annex 2. However, a lesser extent of CO_2 capture might be required if, for example, the legislation enabling CCS sets a reduced $kgCO_2$/MWh (Megawatt hour) criterion. In that event, a portion of the total flue gas stream might be processed through the 90 percent CO_2 capture plant and a portion left untreated so that, on average, the CO_2 capture fraction from the power plant is less.

Three scenarios are considered that might provide the enabling change which results in CCS retrofit being required:

- The international CO_2 emissions market evolves so that participation is mandatory and also the supply of CO_2 emission reduction credits falls short of the demand so that the internationally-traded price of "carbon" rises substantially to the point where implementation of CCS becomes economic compared with buying emission rights. In this scenario, pursuing as much CCS as practicable would be the rational economic choice. 90 percent CO_2 capture reflects this scenario.

- The GoI, either unilaterally or in concert with other countries, decrees that all power plants shall be subject to a maximum emission factor in terms of kilograms (kg) of CO_2 per MWh of electricity generated. 45 percent CO_2 capture reflects this scenario.
- The GoI, or a financing institution, requires that CCS-readiness is taken to the next level by requiring implementation of a commercial-scale plant to prove the technology and provide a model for replication. 22.5 percent CO_2 capture reflects this scenario.

These three scenarios correspond to the proposed CO_2 capture scenarios of 90 percent capture, 45 percent capture and 22.5 percent capture, which would be achieved by 90 percent capture being applied to all, one half or one quarter, respectively, of the flue gas from the host power plant. Since CO_2 capture equipment would comprise multiple gas processing trains, processing a fraction of the flue gas is practical.

3.3.1 Scenarios for the West Java power plant

The size of an individual MEA scrubbing process train is limited by the diameter of the absorbers that could reasonably be manufactured and transported to the power plant site. An initial outline process design indicated that an absorber diameter of up to 14 meters (m) should be technically feasible, based on considerations of column flooding. An absorber height of 25m would be required to achieve 90 percent CO_2 capture. Eight MEA process trains at that size would be required to process all the flue gas from both units at the West Java power plant (i.e., for 2000MW of host power plant capacity).

However, that size of absorber is bigger than has been proven commercially or has been nominated in other CCS studies. Also, that size of prefabricated vessel might be difficult to transport to the site. Therefore, a smaller absorber vessel (10-11 meters diameter) is assessed, which would be sized to achieve 90 percent CO_2 capture with 12 MEA absorber vessels for the 2000MW power plant. On this basis, the scenarios for assessment of CCS on the West Java power plant are shown in Table 3-2.

Table 3-2 Scenarios for CO_2 capture from West Java power plant

	No capture	90% capture	45% capture	22.5% capture
Electricity output – MWe[1]	2000	1449	1723	1862
CO_2 captured – t/hr[2]	0	1558.8	779.4	389.7
CO_2 discharged to air – t/hr	1,732	173.2	952.6	1342.3
Fraction of power plant flue gas sent to CO_2 capture	0%	100%	50%	25%
CO_2 emission - kg/MWh[3]	866	119	553	721
Number of MEA trains	0	12	6	3
Annual CO_2 storage at 80% capacity factor – million tonnes	0	10.92	5.46	2.73

Notes: [1] MWe is Megawatts of electricity; [2] tonnes/hr is tonnes per hour; [3] kg/MWh is kilograms per Megawatt hour.

3.3.2 Scenarios for South Sumatra power plant

The proposed power plant in South Sumatra will have a power output of 600MW from the host power plant, as 1 x 600MWe supercritical unit. As shown in Table 3-1, this host power plant would be slightly less thermally efficient than the proposed West Java power plant. Hence, the CO_2 output from the South Sumatra power plant will be about one third of the CO_2 output from the West Java power plant. Accordingly, four of the MEA CO_2 capture trains of the size assessed for West Java would be needed for 90 percent CO_2 capture. On this basis the scenarios for assessment of CCS on the South Sumatra power plant are shown in Table 3-3.

Table 3-3 Scenarios for CO_2 capture from South Sumatra power plant

(1 x 600 MWe supercritical configuration)

	No capture	90% capture	45% capture	22.5% capture
Electricity output - MWe	600	415	507	554
CO_2 captured – t/hr	0	527	264	132
CO_2 discharged to air – t/hr	586	59	322	454
Fraction of power plant flue gas sent to CO_2 capture	0%	100%	50%	25%
CO_2 emission factor - kg/MWh	976	142	635	819
Number of MEA trains	0	4	2	1
Annual CO_2 storage at 80% capacity factor – million tonnes	0	3.68	1.84	0.92

3.3.3 Comparison with natural gas power plant emission factors

As noted above, the 45 percent capture scenario (i.e., 90 percent CO_2 capture from half of the power plant flue gas) is founded on the scenario that coal-fired power plants would have a limited CO_2 emission factor (e.g., no greater than that of an equivalent gas-fired power plant). Figure 3-1 shows a comparison of power plant CO_2 emission factors based on the data in Table 3-2 and Table 3-3 and on the following assumptions for gas-fired power plants:

- CO_2 emission factor for natural gas = 53 $kgCO_2/GJ_{hhv}$[11]
  (Compared with 93 kg CO_2/GJ_{hhv} for lignite)
- Natural Gas Combined Cycle (NGCC) power plant thermal efficiency = $50\%_{hhv}$
- Open cycle (Gas turbine only) power plant efficiency = $30\%_{hhv}$

[11] GJhhv denotes gigajoules on a higher heating value basis.

Figure 3-1 Comparison of CO_2 emission factors

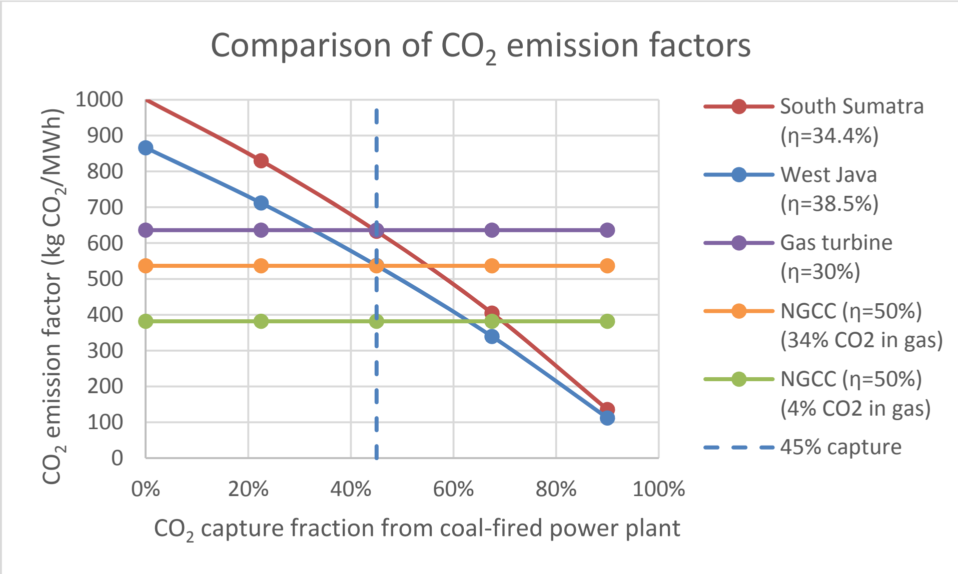


Figure 3-1 shows that 45 percent CO_2 capture from the South Sumatra power plant would reduce the power plant CO_2 emission factor to the same as an equivalent open-cycle gas turbine. To match the emissions from a natural gas combined cycle (NGCC) power plant, 66 percent CO_2 capture from the coal-fired power plants (CFPP) would be required. However, Figure 3-1 also shows that 45 percent CO_2 capture from the West Java power plant would reduce the CO_2 emission factor to the same as an equivalent NGCC power plant if that power plant is sourced with fuel from a gas well containing 34 percent CO_2 and that off-site CO_2 emission is taken into account.

Likewise, if the gas used in an NGCC has been supplied as liquefied natural gas, then there would be substantial pre-combustion CO_2 emissions associated with the liquefaction, transportation and regasification of the LNG. In this case, taking those pre-combustion emissions into account, the overall CO_2 emission factor would likely be about equivalent to the emission factor for a coal-fired power plant with 45 percent CO_2 capture.

This latter comparison illustrates that the direct CO_2 emissions from the power plant stack is only part of the greenhouse gas emission consequences of fossil fuel power generation. For a holistic comparison, the emission of CO_2 and methane involved in the production of the power plant fuel should be taken into account via a Full Fuel Cycle (FFC) GHG gas analysis. Such an analysis typically reveals that the greenhouse gas emission from natural gas production, processing and distribution are significantly larger per unit of consumer energy than the emissions from the mining and transport of coal. In particular, if the raw natural gas has a high CO_2 that is stripped and vented as part of the gas processing operation, then the greenhouse "backpack" of pre-combustion emissions carried by that gas when it is delivered to the power plant can be significant.

3.4 Implementation timing

Three implementation delay scenarios of five, ten and fifteen years are used to assess the economic impact of delaying the implementation of CCS. These delay scenarios are made to reflect the fact that implementation of CCS in Indonesia will not occur until institutional readiness is in place. It is expected that the West Java power plant will be commissioned in 2020, that the South Sumatra plant will be commissioned in 2022, and that both power plants will have a 25-year design life ending in 2045 and 2047, respectively. On that basis, the total amounts of CO_2 storage required for CCS on the two power plants are shown in Table 3-4. These are the quantities of CO_2 for which storage locations need to be identified for CCS-ready status.

Table 3-4 Total CO_2 storage requirements (millions of tonnes of CO_2**)**

	CCS implementation in West Java			**CCS implementation in S Sumatra**		
Capture	**2025**	**2030**	**2035**	**2027**	**2032**	**2037**
22.5%	55	41	27	18	14	9
45%	109	82	55	37	28	18
90%	218	164	109	74	55	37

4 CAPTURE STUDY

4.1 Introduction

This chapter presents a technical feasibility study for Capture-Ready status of two power plants – one in West Java and one in South Sumatra. Both power plants will utilize lignite coal as their main fuel. This chapter focuses on a preliminary engineering design of the CCS retrofit facilities to capture CO_2 from boiler stack gas, aiming to achieve the best CO_2 capture scenario in terms of technical performance and financial outcome. In addition, this chapter also covers some recommendations regarding selection of equipment.

Even though CCS implementation is unlikely to eventuate before 2025, which would be some years after the power plants are commissioned, CO_2 capture design, site area requirements and additional equipment locations would need to be defined in the original respective power plant design and layout to prepare the power plants for later CCS implementation and thereby achieve future-proofing of the power plant design.

Figure 4-1 The capture-ready facilities retrofit in the power plant

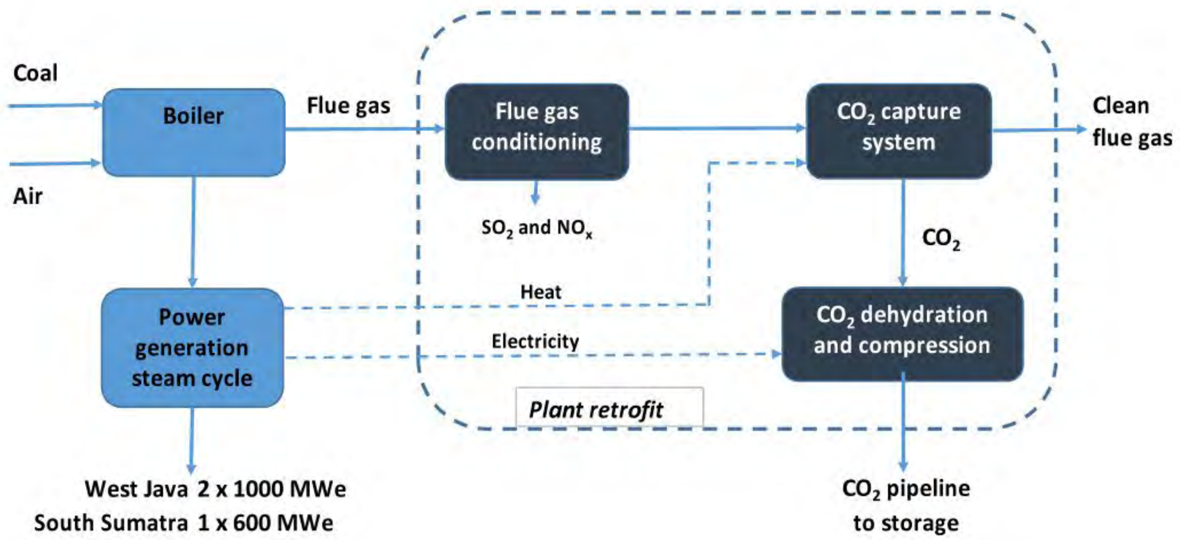


Figure 4.1 shows a simplified schematic of the additional equipment that would be required to add CO_2 capture to a coal-fired power plant.

4.2 Power plant layout considerations for capture-readiness

CCS-R status requires the presentation of a scheme that uses commercially proven technology that is suited to the specific circumstances of the power plant. MEA scrubbing is a proven solvent for CO_2 removal from products of combustion. Advanced amine systems, such as methyldiethanolamine (MDEA), may be considered if there is sufficient confidence that such solvent systems are commercially proven for this application.

The main impact on the power plant of the addition of CO_2 capture is the requirement for an energy source for the solvent reboiler. That energy is most efficiently provided in the form of low-pressure steam extracted from the power plant steam cycle. About 70 percent of the steam that would normally be passed though the low -pressure (LP) steam turbo-generator would be required for amine solvent regeneration in the CO_2 capture plant, thus reducing the yield of electricity. However, the electricity generated in the power plant's high-pressure and medium-pressure turbo-generators would be essentially unchanged. To be capture-ready, a plan for extracting LP steam from the power plant has to be developed.

The MEA scrubbing process also requires a very low level of impurities, principally NOx and SO_2, in the flue gas from the power plant in order to avoid excessive degradation of the recycled solvent.

4.2.1 Oxides of nitrogen (NO_x)

Environmental air quality legislation in Indonesia requires the discharge of NO_x to be below 750 mg/Nm^3 (365 ppm)[12] in the discharged flue gas, which is usually achieved with low-NO_x burners in the combustor. However, the MEA process typically requires the NO_x content of the feed gas to contain no more than 20 ppm. Therefore, an additional process with about 95 percent NO_x reduction would be required. Selective Catalytic Reduction (SCR) could achieve that level of NO_x reduction by reacting NO_2 with ammonia in a catalyst bed at elevated temperature to yield nitrogen and water vapour. To be capture-ready, a power plant would require space to be allocated for retrofitting SCR in the hot gas path.

In some countries, environmental criteria are stricter than in Indonesia, meaning that SCR has to be included in standard power plant designs without CO_2 capture. If there is the likelihood that stricter environmental criteria might be applied in Indonesia, then provision of space for later addition of SCR could be considered as prudent future-proofing of the power plant design and might not be attributed to the consequences of making the power plant capture-ready.

4.2.2 Sulphur dioxide (SO_2)

Environmental air quality legislation in Indonesia requires the discharge of (SO_2) also to be below 750 mg/Nm^3 (263 ppm) in the discharged flue gas.

In the case of the West Java plant, the intention is to use lignite fuel with 1.8 percent (dry ash-free) sulphur content, which would result in a flue gas with 4825 mg/Nm^3 of SO_2 if uncontrolled. Scrubbing of flue gas with seawater is proposed at a coastal location, as the flue gas desulphurisation (FGD) process in the host power plant, to reduce the SO_2 content of the flue gas by 85 percent to comply with the air quality criterion.

In the case of the inland South Sumatra plant, seawater scrubbing is not possible and no other FGD is proposed. The design lignite has a sulphur content of 0.86 percent (dry ash-free), which would result in a flue gas SO_2 concentration of 2263 mg/Nm^3. The lignite sulphur content would need to be less than 0.28 percent to give a flue gas compliant with the 750 mg/Nm^3 air quality criterion.

The MEA process typically requires the feed gas to contain less than 10 ppm SO_2. Therefore, for a flue gas that is compliant with the 750 mg/Nm^3 (263 ppm) air quality criterion, an additional FGD process with 96 percent SO_2 reduction capability would be required as part of

[12] mg/Nm^3 denotes milligrams per normal cubic metre and ppm denotes parts per million.

the CO_2 capture retrofit. A wet scrubbing process, such as limestone/gypsum FGD, would need to be located in the flue gas path after gas cooling and prior to the CO_2 capture process.

4.3 Technical feasibility study of CCS-Ready facilities

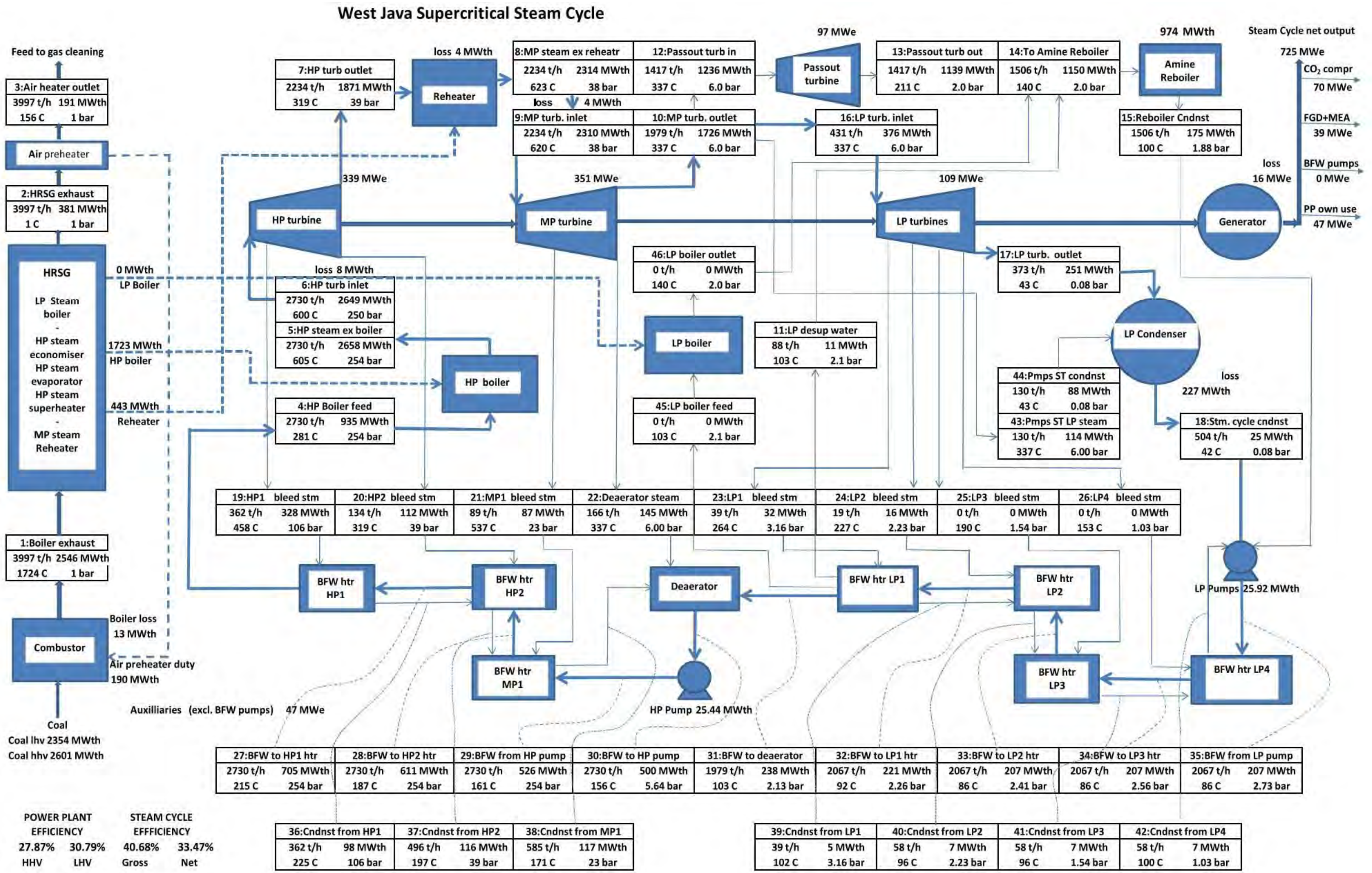
4.3.1 Framework model for power plant modification assessment

An Excel spreadsheet power plant model covering mass, energy and element balancing has been developed for this study to enable rigorous assessment of the changes to the power plant arising from the integration of CO_2 capture. The model allows for six parallel cases to be assessed and compared. The Framework model describes the power plant *via* 56 input parameters defining the process configurations, the fuel properties and analyses, and the steam cycle configuration and thermodynamics.

There are two computational sections: boiler and steam cycle. The boiler section is based on mass, energy and element balancing calculations to assess the combustion process and flue gas processing stages. In particular, this section determines the acid dew point of the flue gas, which impacts on the flue gas temperature profiles. The boiler section relies on a database of physical and chemical properties of fuels and gases. The steam cycle section embodies representations of a supercritical steam cycle with high-pressure turbine, reheater, medium-pressure turbine, low-pressure condensing turbine, condenser and eight-stage boiler feed water heating system. The steam cycle calculations use the “X-steam” steam properties software with supercritical capabilities. Heat exchanger pinch point methodology is used to optimize the steam cycle thermal efficiency. Figure 4-2 presents the steam cycle representation for one unit of the West Java plant ultra-supercritical steam cycle with low-pressure steam extraction for the amine reboiler at 90 percent CO_2 capture. In this example, the nominal net output to the grid of 1000MW is reduced to 725 MW net output due to the integration of LP steam extraction for the amine reboiler.

The Framework model has been used to develop the outline power plant definitions presented in pre-feasibility studies for the West Java and South Sumatra power plants to ensure that the power plant assessment data with and without CO_2 capture are determined on a consistent basis.

Figure 4-2 Framework model of West Java 1000MW unit steam cycle with CO_2 capture



4.3.2 Flue gas conditioning design basis

Flue gas from the boiler needs to be treated before being processed in the CO_2 capture system. Based on the framework model described in Section 4.2.2, Table 4-1 shows the raw flue gas outlet conditions from the boiler in the host power plants.

Table 4-1 Flue gas design basis in West Java and South Sumatra power plants

Flue gas condition after air preheater	**West Java 2x 1000MWe**	**South Sumatra 600MWe**
Mass flow (t/h)[1]	7995	2857
Temperature (°C)[2]	156	152
Pressure (bar)[3]	1.1	1.1
Composition (vol%)[4]		
H_2O[5]	17.57%	25.28%
N_2[6]	66.57%	60.31%
CO_2[7]	14.09%	12.87%
O_2[8]	1.59%	1.45%
SO_2 (ppm dry basis)[9]	1688	792 (0.86% S in fuel)[10]
NO_2 (ppm dry basis)[11]	<365	<365

Notes: [1] t/h denotes tonnes per hour; [2] °C denotes degrees Centigrade; [3] bar denotes a metric unit of measure for pressure. One bar is approximately equal to the atmospheric pressure on earth at sea level; [4] vol denotes volume as the basis of measurement of gas composition. [5] H_2O denotes water; [6] N_2 denotes nitrogen; [7] CO_2 denotes carbon dioxide; [8] O_2 denotes oxygen; [9] SO_2 (denoting sulphur dioxide) is based on 100 percent conversion of sulphur in fuel and ppm denotes parts per million; [10] S denotes Sulphur; [11] NO_2 denotes all oxides of nitrogen (NO_x) on an NO_2 equivalent basis. The NO_2 content is based on Low-NOx (oxides of nitrogen) burners to achieve <750 mg/Nm^3.

There are three possible schematic configurations to treat NO_2 and SO_2 from flue gas. These three configurations are differentiated by the NO_x removal sequence (Jeffers, 2008) as illustrated in .

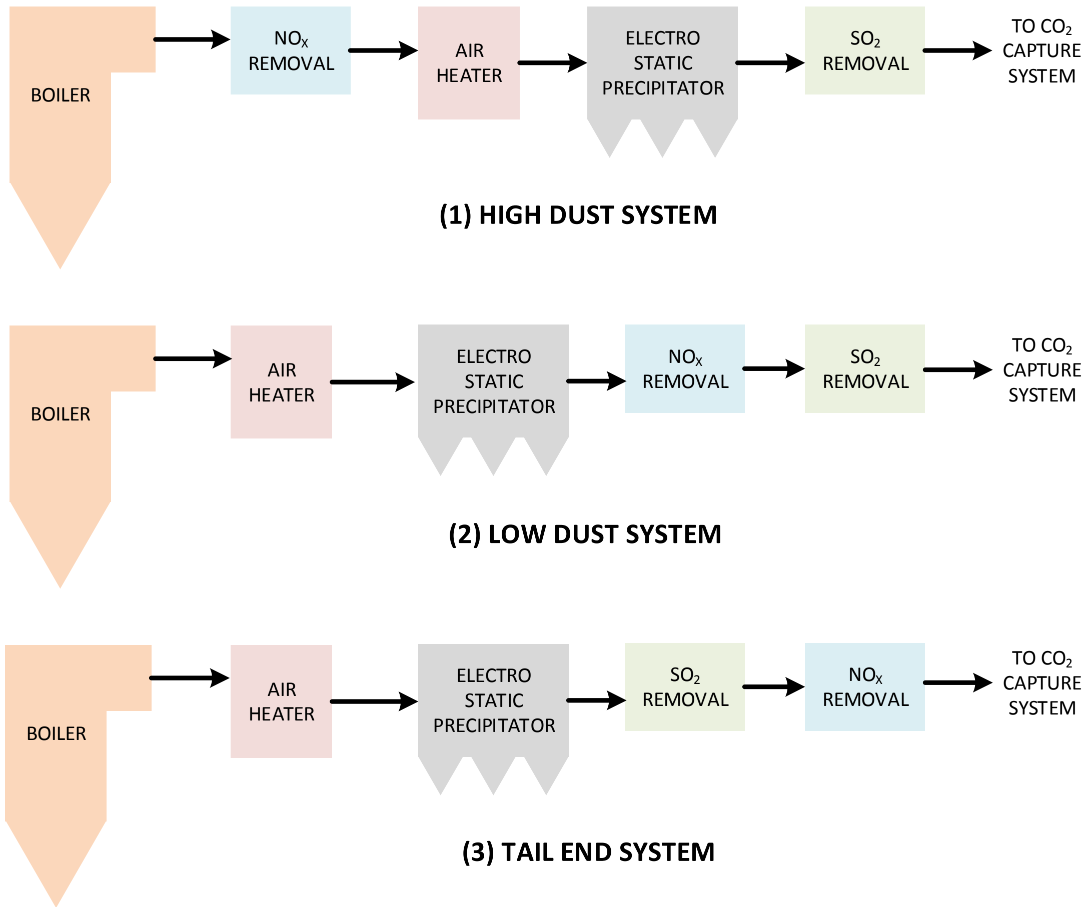
In the High Dust configuration, the SCR reactor is placed in the most thermally efficient location between the economizer and the air preheater. In this configuration, the catalyst is exposed to fly ash and chemical compounds present in the flue gas, which have the potential to degrade the catalyst mechanically and chemically. However, as evidenced by the extensive use of this configuration, proper design of a high-dust SCR system can mitigate the mechanical and chemical impacts on the catalyst.

In the Low Dust configuration, the SCR reactor is located downstream of the electrostatic precipitator (ESP). This configuration would reduce the degrading effect of fly ash on the catalyst.

In the Tail End configuration, the SCR reactor is installed downstream of the flue gas desulfurization unit. The tail end configuration is implicitly low-dust. However, this configuration is typically less thermally efficient and more expensive than the high-temperature configurations due to associated flue gas reheating requirements.

Of the three configurations illustrated in Figure 4-3, the High Dust configuration is selected for the flue gas conditioning study, because a high operating temperature is required to maximize NO_x conversion and the High Dust configuration is the most thermally efficient. The fly ash issues can be managed with modern designs. The optimum operating temperature for SCR is about 400°C so the boiler exit temperature would need to be about that temperature. The residual heat in the flue gas is recovered in an air preheater and recycled to the boiler. However, the inclusion of SCR would result in an increase in the air preheater duty.

Figure 4-3 Three possible configurations of flue gas conditioning



4.3.3 NO_x removal technology

NO_x removal technology is required in addition to NO_2 reduction that can be achieved with Low-NO_x burners in the combustion chamber. Generally, post-combustion technologies for the reduction of NO_X are: selective non-catalytic reduction (SNCR) and selective catalytic reduction. Each of these technologies requires the introduction of a reagent, such as ammonia or urea that will selectively react with NO_x. This reaction occurs in the presence of oxygen. The following simplified chemistry summarizes the reactions involved in the post-combustion controls to convert NO_x to elemental nitrogen (Bell & Buckingham, 2002).

SNCR Reaction : $2NO + NH_2CONH_2 + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$

SCR Reactions : $\begin{cases} 4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O & \text{(catalytic reaction)} \\ 2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O & \text{(catalytic reaction)} \end{cases}$

Table 4-2 provides a summary of the effectiveness and relative costs for these technologies. This table lists the NO_x reduction achieved by each technology as a percentage of the NO_x prior to the implementation of the combustion control.

Table 4-2 Design criteria for SCR facilities

Control technology	NO_x Reduction (%)
SNCR	**40-60**
SCR	**80-95**

Based on Table 4-2 (Buckingham, 2002), it can be concluded that SCR technology is the most viable option to treat flue gas outlet from the electrostatic precipitator, when a high capture rate is required. With this technology, 95percent of inlet NO_x can be reacted catalytically to achieve 20 parts per million by volume (ppmv) in the SCR outlet. The two most used catalyst types in the industry (Jeffers, 2008) are:

Plate-type Catalyst

- Most suitable for high dust concentration;
- TiO_2, V-oxide/W-oxide/Mo-oxide as the active catalytic material;
- Thermal and mechanical resistance; and
- Low SO_2/SO_3 conversion rate.

Honeycomb Catalyst

- Most suitable for low dust situation;
- TiO_2, V-oxide and W-oxide as the active catalytic material;
- Homogeneously extruded ceramic, and
- High active surface area per unit volume.

According to the International Energy Agency Greenhouse Gas Research and Development Program (IEAGHG, 2006), 20 ppmv NO_x is a reasonable limit to avoid excessive amine absorbent solvent degradation in the CO_2 capture system. Therefore, SCR is identified for both the West Java and South Sumatra power plants as an additional process that would be required for implementation of CCS.

The maximum size of proven SCR unit capacity for a single-train unit installed worldwide is 100-850 MWe (Srivastava, 1997). Table 4-3 shows the number of trains and other SCR design information for the study. The ammonia demand is calculated on the basis of 10 percent more than the stoichiometric requirement.

Table 4-3 SCR design criteria for West Java and South Sumatra power plants

	West Java (2x 1000) MW	South Sumatra (1x600MW)
Max single train SCR Capacity	700MW	600MW
Catalyst type	Ceramic Honeycomb	
Minimum number of trains	4	1
Fuel	High Sulphur Lignite	Lower Sulphur Lignite
NO_x Inlet (pounds per million Btu [lb/MMBtu])	0.57 (335 ppmv)	0.57 (335 ppmv)
NO_x Reduction (%)	94%	
NO_x Outlet (lb/MMBtu)	0.034 (20 ppmv)	0.034 (20 ppmv)
Ammonia demand (tonnes/hr)	3.56	1.19

4.3.4 SO_2 removal technology

Sulphur dioxide in the flue gas is produced from the combustion of sulphur in the lignite. Combustion in the boiler converts both organic and inorganic sulphur in the fuel to gaseous SO_2. Like NO_x, SO_2 concentration in the flue gas has to be severely limited to avoid excessive amine degradation. SO_2 in the flue gas should be below 10 ppmv before being introduced into an amine CO_2 capture system. SO_2 reacts with amine solvent to form a sulphite that has to be removed. In addition to requiring the removal of degradation products, there would be more amine solvent makeup required to compensate for solvent loss (Nielsen, 1997). Hence, SO_2 removal before CO_2 capture would be required. Numerous systems for flue gas desulfurization have been operated worldwide. The classification of many FGD schemes can be considered as two types: wet and dry (DTI, 2000).

Wet FGD Process

> Wet FGD is based on using limestone as a reagent to scrub SO_2 from the flue gas. In order to maintain homogeneous performance and good operability, limestone in the form of slurry is sprayed vertically inside a scrubbing tower. This technology is widely installed and most frequently selected for sulphur dioxide reduction from coal-fired boilers. Typically, SO_2 removal efficiency for wet FGD ranges from 80-98 percent.

Dry FGD Process

> In Dry FGD, flue gas is contacted with alkaline (most often lime) sorbent. The sorbent can be delivered to flue gas in an aqueous slurry form (semi-dry) or a dry powder (dry). As a reaction result, dry waste is produced with handling properties similar to fly ash. Typically, SO_2 removal efficiency for Dry FGD ranges from 50-80 percent.

If the sulphur content of the lignite coal used at the South Sumatra plant is 0.86 percent, then to reach a satisfactory value of SO_2 of 10 ppmv in the treated flue gas, the South Sumatra power plant would require over 98.7 percent removal efficiency, which would be challenging. However, the use of a single FGD process at the South Sumatra plant would be practical if a lower sulphur content fuel (e.g., 0.28 percent sulphur) can be used that would achieve 750 mg/Nm^3 (<263 ppm dry) SO_2 in the host power plant flue gas, thus requiring 96 percent SO_2 removal with FGD.

At the West Java plant, the SO_2 content of the flue gas would be reduced to below the air quality criterion of 750 mg/Nm^3 (<263 ppm dry) with seawater scrubbing. A further 96 percent reduction in SO_2 would be required to achieve 10ppm SO_2 in the feed gas to make it feasible to use amine scrubbing. A single step SO_2 removal process is not sufficient for the West Java power plant case.

Therefore a high-efficiency wet FGD process would be required for both applications as illustrated in Figure 4-4.

Wet FGD can be operated reliably in a natural oxidation mode under favorable conditions. However, for the majority of applications, it is necessary to control the extent of oxidation in order to improve operational reliability of the system. Over the years, several process variations have been designed to improve the operational reliability of wet FGD technology.

One way to prevent a scaling problem is to blow air into the absorbent slurry to encourage controlled oxidation outside of the absorber. This type of FGD system, known as limestone forced oxidation (LSFO), provides rapid calcium sulfate crystal growth on seed crystals. It minimizes scaling in the scrubber and also results in slurry that can be more easily dewatered. Consequently, the LSFO system has become the preferred technology worldwide (Srivastava, 2000).

Table 4-4 gives some design characteristics for wet FGD at both power plants. The limestone demand is calculated on the basis of 10 percent more than the stoichiometric requirement. Unlike SCR for NOx systems, which only need ammonia dosing as auxiliary equipment, wet FGD systems require significant sub-systems. These sub-systems contribute to the cost of FGD and to the site layout requirements.

Figure 4-4 NOx and SO_2 Removal Configurations

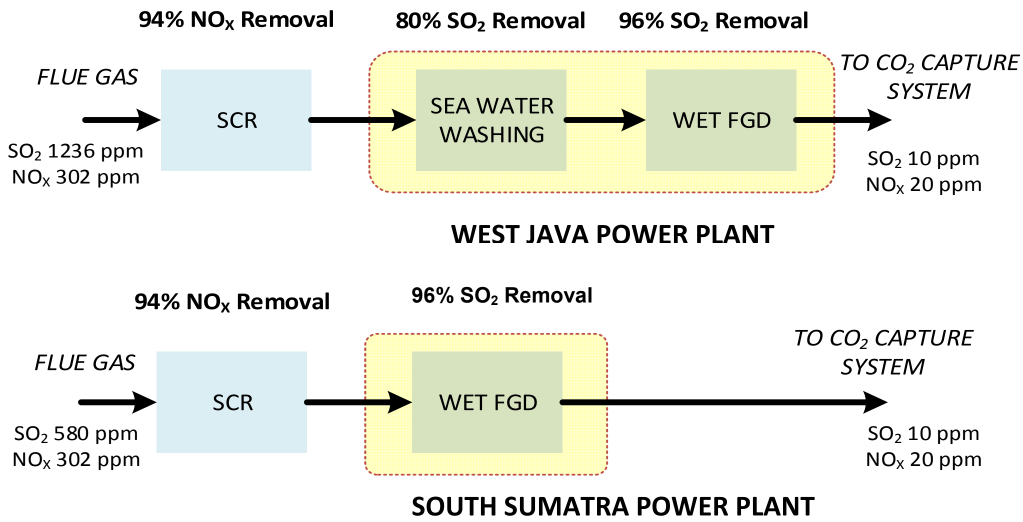
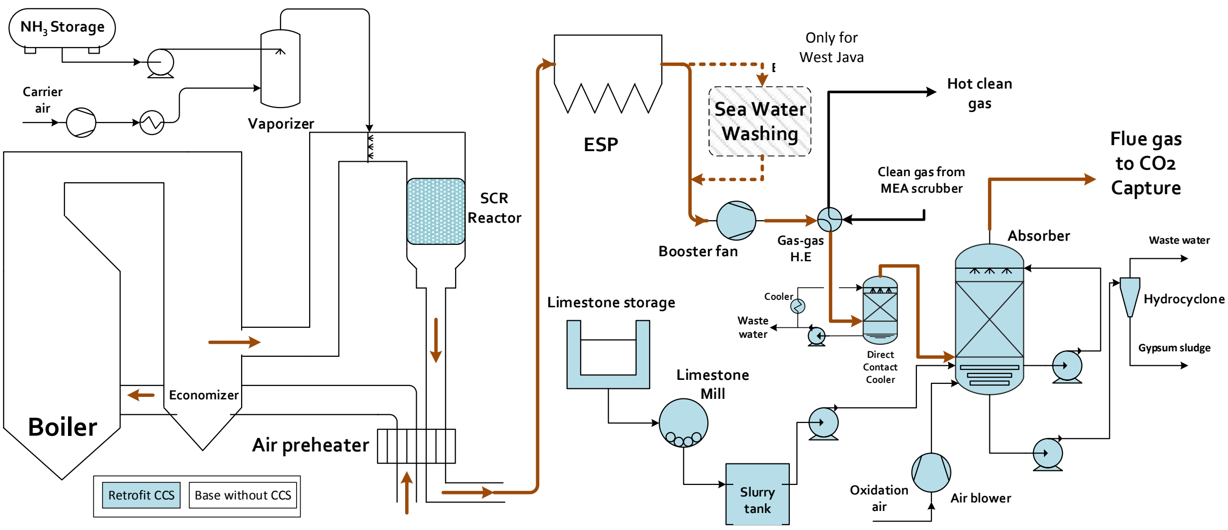


Table 4-4 FGD design criteria for West Java and South Sumatra Power Plants

	West Java (2x 1000 MW)	South Sumatra (1x600MW)
Single Train Unit Size	500 MWe	600 MWe
Number of Trains	4	1
Flue gas flow (MMscf [1] per minute)	2.49	1.99
SO_2 inlet (ppmv dry)	1688	<263 (0.4% Sulphur basis)
FGD Removal Efficiency		
Sea Water Washing	85%	-
LSFO	96%	96%
SO_2 outlet (ppmv dry)	10	10
Limestone demand (tonnes/hr)	42.50	6.65
[1] MMscf = million standard cubic feet		

Figure 4.5 shows the overall process plant diagram for flue gas conditioning in both power plants.

Figure 4-5 Flue gas conditioning overall process flow diagram



It is well established that the best proven technology for the separation of CO_2 from the products of combustion is by the use of an amine solvent in a chemical scrubbing process (Rubin, 2002) and (Folger, 2010). The amine scrubbing process, illustrated in

Figure 4-6, involves contacting an aqueous solution of amine with the flue gas at low temperature in an absorber column where CO_2 combines chemically with the amine. The CO_2-rich solution is then heated to cause the CO_2 to chemically dissociate from the amine. The CO_2 is recovered from the hot amine solution in a regeneration column. The depleted amine solvent is recycled to the absorber. The principal utility requirement for the amine scrubbing process is low-grade steam for the solvent regeneration column

4.3.5 Amine-based post-combustion CO_2 capture

The simplest amine is MEA (monoethanolamine) which is well proven commercially as a reagent for CO_2 capture in many commercial installations around the world (Bhown, 2011). MEA has been used for assessment of the CO_2 capture in this study.

The use of more complex amine compounds, such as MDEA (Methyldiethanolamine) and mixtures of amine compounds have been successfully used in some applications. The use of alternative amines or other CO_2 capture technology is discussed in Annex 3.

Table 4-5 provides the flue gas design basis used for further calculations.

Table 4-5 Amine scrubber feed gas for West Java and South Sumatra Power Plants

Feed gas to MEA scrubber	West Java 2x1000 MWe	South Sumatra 1x600 MWe
Mass flow (tonne/hr)	7370	2474
Temperature (°C)	40	40
Pressure (bar)	1.1	1.1
Composition (%mol)		
H_2O	6.71%	6.71%
N_2	75.46%	75.39%
CO_2	16.12%	16.16%
O_2	1.70%	1.74%
SO_2 (ppm dry)	10	10
NO_2 (ppm dry)	20	20

Figure 4-6 Basic amine scrubbing CO_2 capture process flow diagram

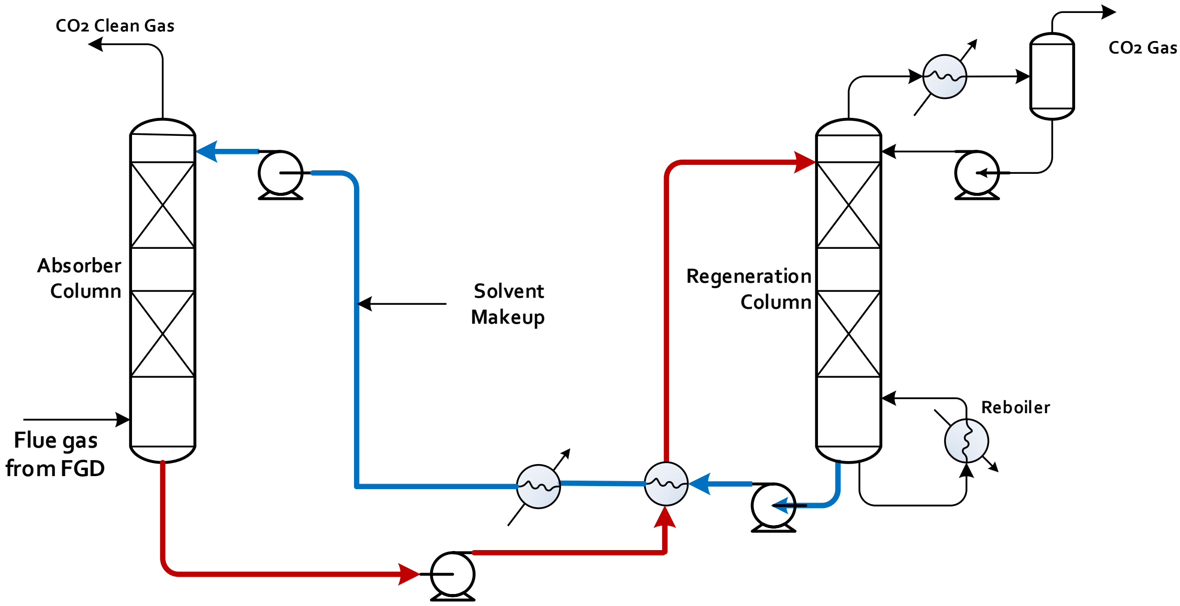


Figure 4-7 CO_2 capture simulation diagram

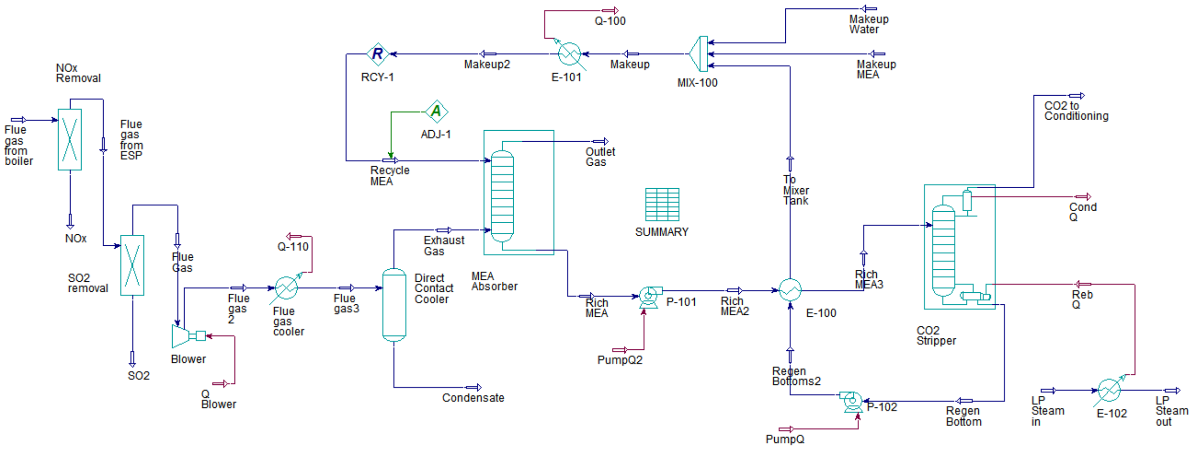


Figure 4-7 shows a schematic diagram of the Aspen computer model that has been used for this assessment. The simulation base calculation method was used to maintain homogenous calculation methodology and accuracy. For this study, the latest Aspen HYSYS Simulator version 8.6 was utilized to simulate and evaluate performance of post combustion CO_2 capture. Key input parameters for this Aspen HYSYS modelling are as follow:

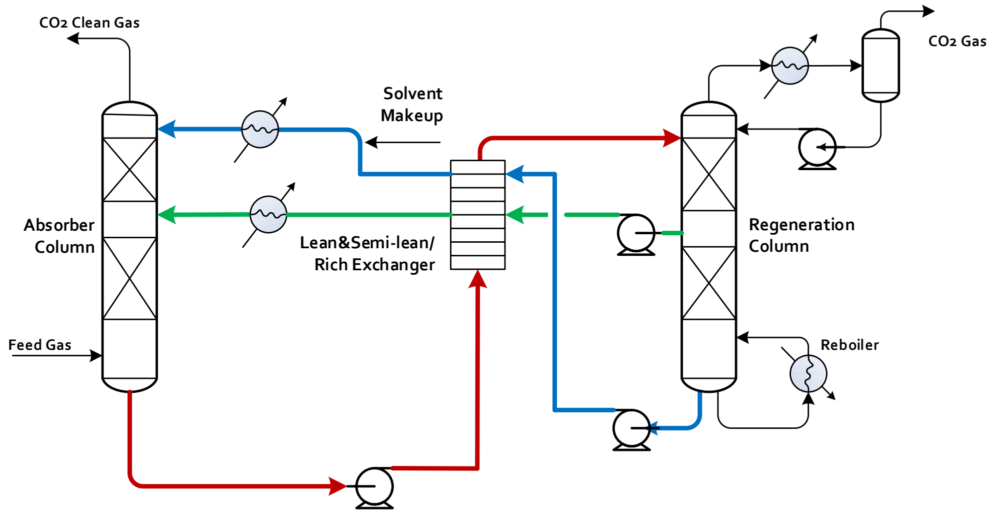
- Fluid package : Acid Gas
- MEA concentration : $\leq$ 30 percent (by weight)
- Flue gas inlet temperature : 40°C
- Rich MEA inlet temperature : 105°C
- MEA absorber pressure : 1.1 bar
- CO_2 stripper pressure : 1.8 bar
- Rotating equipment efficiency : 75 percent
- Minimum temperature approach : 10°C

With these calculation assumptions, the CO_2 capture system can be realistically and accurately evaluated with mass and energy balance calculations and the critical parameter of regenerator energy requirement can be determined.

Several process refinements, and optimisations and alternative configurations have been developed to minimize the energy penalty of CO_2 capture. For example, the regeneration temperature has to be optimized to compromise between energy demand and thermal degradation of the solvent. Another key compromise is between the concentration of MEA in the solvent and the corrosion of process equipment. Alternative process configurations include a split flow configuration and also a vapour recompression configuration. Figure 4-8 illustrates the split flow configuration.

A key outcome of the investigation carried out with amine process modelling is that the optimized energy requirement for amine regeneration is 4.5 gigajoules (GJ) per tonne of CO_2 captured.

Figure 4-8 CO_2 capture simulation diagram for split flow configuration



The sizes of major equipment items are also determined by the Aspen model. The most critical equipment dimension is the diameter of the absorber column. The absorber is a packed column in which amine solution flows down over packing where it is contacted with flue gas flowing up the column. The flows in the column have to be carefully designed to avoid the down flowing liquid being held up by the up-flowing gas, which would cause the column to flood. Commercial designs exist up to 14 meters diameter, but an absorber diameter of 11 meters is well proven and a vessel of that size would be more easily transported. At that size, six MEA absorber columns would be required to process all the flue gas from each of the 1000MW power plant units. The corresponding numbers of process trains are summarized in Table 4-6.

Table 4-6 Number of CO_2 capture units required

Power plant	**CO_2 capture fraction**	**MEA concentration (% by weight)**	**Number of trains**	
			Absorber	**Regenerator**
West Java (2x1000 MWe)	22.5%	20	3	2
	45%	25	6	3
	90%	30	12	6
South Sumatra (600 MWe)	22.5%	20	1	1
	45%	25	2	2
	90%	30	4	4

4.3.6 CO_2 conditioning (dehydration and compression)

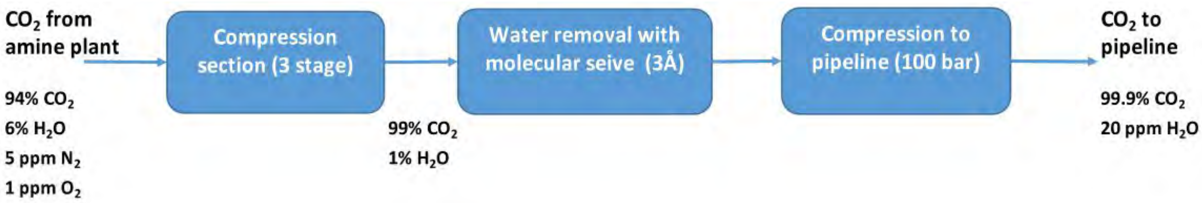
CO_2 that has been stripped from the amine solvent in the regenerator tower will be prepared in a CO_2 conditioning system. In order to transport large amounts of CO_2 efficiently, the CO_2 must be liquefied and maintained in the liquid phase (i.e., above 74 bar pressure) in the pipeline in order to avoid unnecessary problems of vaporization while delivering it. The critical temperature of CO_2 is 31°C, so when the CO_2 is at a higher temperature it would be a supercritical fluid rather than a liquid. To provide for the pipeline pressure, CO_2 is compressed at the power plant site with cooling and dehydration to 110 bar. The liquid CO_2 quality specifications for pipelining are listed in Table 4-7.

Table 4-7 CO_2 pipeline specifications

Component	Concentration (% by vol)
CO_2	> 95%
Water (H_2O)	<50 ppm
N_2	< 4%
O_2	< 10 ppm
Hydrocarbon	< 5%
Sulfur	< 1400 ppm

CO_2 from the scrubber is saturated with water after being regenerated with steam in the stripper column. Excessive amounts of water would cause corrosion problems in the delivery pipe. Therefore, a water removal process must be included in the CO_2 compression train. A CO_2 conditioning configuration is illustrated in Figure 4-9.

Figure 4-9 CO_2 conditioning configuration



The water concentration would be reduced to less than 50 ppm using molecular sieve adsorption technology, which has been proven mature in chemical industries. In order to separate CO_2 and water, a molecular sieve with a 3Å (Angstrom units)[13] pore size is the most suitable pore size because H_2O has 2.8Å diameter (UOP, 2001).

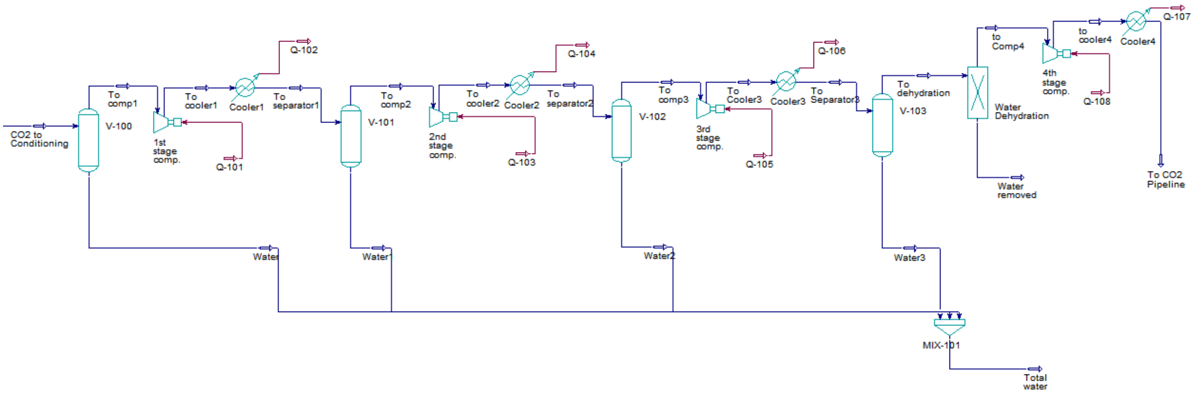
Additional to the basic assumptions of the CO_2 capture system, a simulation was conducted for CO_2 conditioning systems assuming that:

- Pressure ratio of the compressor is ≤ 3; and
- Compressor intercooler can reduce the temperature to 50°C.

Figure 4-10 shows the detailed process configuration for the CO_2 compression train modelled with Aspen HYSYS simulator version 8.6.

[13] A very small unit of length (equivalent to 1×10^{-7} millimeters).

Figure 4-10 CO_2 compression and dehydration simulation diagram



4.4 Outputs from the Capture Study

4.4.1 Reduction in net electricity output

Table 4.8 shows that installation of 90 percent CO_2 capture on the West Java power plant would reduce the net electricity output to the grid from 2000MW to 1450MW. That corresponds to a 27.5 percent reduction in net output for the same coal feed rate (i.e., the thermal efficiency of the West Java power plant would be reduced from 42.5%$_{lhv}$ to 30.8%$_{lhv}$) as shown in Figure 4.2. Likewise, for the South Sumatra power plant, the overall thermal efficiency would reduce from 40.8%$_{lhv}$ to 28.2%$_{lhv}$ (i.e., a 30.8 percent reduction in net power out to the grid).

Table 4.8 shows that the main cause of electricity output reduction is the net loss due to LP steam use for CO_2 capture such that the electricity generation capacity of the LP steam turbine is greatly reduced. That assessment is based on the MEA amine scrubbing plant having an assumed energy demand of 4.5 GJ/tonne of CO_2 captured, which reflects a well-proven commercial process. There is substantial research and development (R&D) effort in exploring more efficient CO_2 capture processes, which are discussed in more detail in Annex 3.

Substantially lower reductions in net electricity delivered to the transmission grid (e.g., less than 20 percent) are reported for some CCS schemes that are under development or are the subject of desk studies. Such improved performance could be largely attributable to the host power plant having a much higher thermal efficiency. If the host power plant is more efficient, then the overhead losses of electricity -- due to LP steam offtake and own use for processes and CO_2 compression -- would be a smaller fraction of the output of the host power plant.

The relatively low thermal efficiencies of the host power plants in West Java and South Sumatra are partly due to the use of low-quality lignite fuel, particularly in the case of the South Sumatra plant. Also, the equatorial location of the power plants means that the bottom temperature of the thermodynamic steam cycle is not as low as would be the case in higher latitudes.

4.4.2 Additional operating costs

The addition of flue gas processing, CO_2 capture and CO_2 compression have demands for utilities and chemicals. The utilities and chemicals demands determined with the Framework model and the Aspen modeling are listed in Table 4-8 for the 90 percent capture reference cases. The main utilities requirement is LP steam for the MEA process regeneration. As described above, that LP steam demand is integrated into the power plant steam cycle and so is manifest as a net loss of electricity output from the power plant. Accordingly, that energy demand is expressed in Table 4-8 as an electricity consumption, although it is actually a net loss of electricity production.

Table 4-8 Electricity, utilities and chemicals demand for 90 percent capture

Electricity production and own use MWe	**West Java (2x 1000 MW)**	**South Sumatra (600 MW)**
Gross power generated in host power plant	2146	646
Own use for host power plant (including Boiler Feed Water pumps)	146	46
Net power output from host power plant	**2000**	**600**
Net loss due to LP steam use for CO_2 capture	332	111
Power for CO_2 capture plant and FGD plant	36	12
Power for CO_2 compression and dehydration	182	62
Net output from power plant with CCS	**1450**	**415**
Chemicals and utilities		
Make up MEA solvent (tonnes/hour)	5.2	2.2
Limestone for FGD plant (tonnes/hour)	21.25	6.66
Ammonia for SCR plant (tonnes/hour)	0.85	0.57
Cooling water duty (thousand tonnes/hour)	88	25
By-product gypsum production (tonnes/hour)	28.4	8.9

The flue gases from lignite combustion have a high moisture content. When those flue gases are cooled in a direct contact water wash cooler, after the air preheater and before the FGD plant, there is a net make of water due to condensation from the feed gas. If that surplus wash water were to be cleaned, it could be used as process water elsewhere in the process. Accordingly, it is assumed that there would be no need to purchase clean water for the CO_2 capture process. However, if evaporative cooling towers are used to meet the cooling duty, then both the host power plants, both with and without CCS, would be net consumers of water. The proposed FGD process would produce by-product gypsum (calcium sulphate), which could be a saleable product to offset some of the limestone cost.

Annual operation and maintenance costs for the amine plants is shown in Table 4-9.

Table 4-9 Estimated annual O&M cost for CO_2 capture in amine plant

US$million/year	**90% capture**	**45% capture**	**22.5% capture**
West Java Power Plant	182.3	147.7	115.3
South Sumatra Power Plant	65.0	53.1	39.7

4.4.3 Incremental capital cost

The additional capital equipment required to implement CO_2 capture on a power plant comprises: SCR, FGD, MEA, CO_2 compression, and also a low -pressure steam power recovery turbine. Table 4-10 presents capital cost estimates for this process equipment based on Aspen modeling, with reference to literature sources. These capital cost estimates are made at the budget estimating level and are subject to a wide margin of uncertainty. The capital cost estimates are made on the 90 percent capture cases and are scaled to give estimates at 45 percent and 22.5 percent capture in accordance with the number of process trains required.

Table 4-10 Capital cost estimates for CO_2 capture equipment (US$ million)

West Java	**90% capture**	**45% capture**	**22.5% capture**
SCR process plant	180	180	180
FGD process plant	378	214	119
MEA process plant	870	460	291
CO_2 compressors and dryers	173	123	61
LP steam power recovery turbine	80	40	30
Total	1681	1016	681
South Sumatra	**90% capture**	**45% capture**	**22.5% capture**
SCR process plant	56	56	56
FGD process plant	128	98	79
MEA process plant	425	248	159
CO_2 compressors and dryers	94	58	43
LP steam power recovery turbine	40	30	20
Total	743	490	357

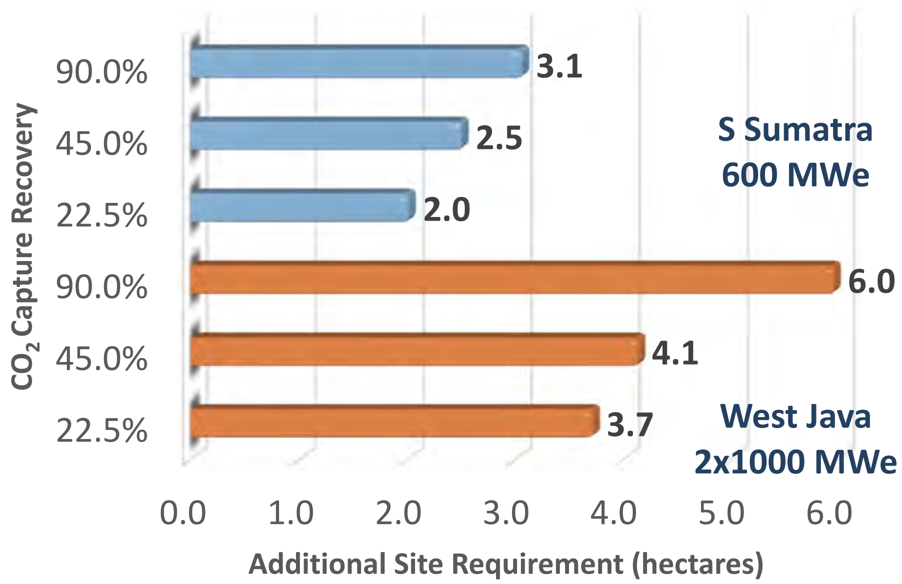
The process plant equipment listed in Table 4-10 would not need to be purchased until the decision had been made to implement CCS. At the time of the design and construction of the Capture-Ready host power plant, there would be minimal additional equipment cost, but the plant layout and equipment design would need to take account of the potential future implementation of CO_2 capture. Also, land area would need to be allocated on the site for future CO_2 capture equipment. In the source case in West Java, adequate land has already been purchased, which would be able to accommodate implementation of CO_2 capture. However, in the case of South Sumatra or other future power plants, land acquisition for CO_2 capture might need to be undertaken at the time of developing the host power plant, so that the power plant can be deemed to be capture–ready.

4.4.4 Additional site area requirements

In order to be ready to implement a CO_2 capture system and its supplementary facilities, four major process areas would need to be allocated space on the power plant site: SCR, FGD, MEA and CO_2 compression. These areas of land in a capture-ready power plant might be used for some temporary purpose, such as a laydown area during power plant construction, a convenient stock yard, or car parking. However, the ability to re-purpose those areas for future process plants would need to be retained.

Figure 4-11 presents an estimate of the total additional land areas that might be required for CO_2 capture equipment for a typical power plant configuration. If the extent of CO_2 capture is less than 90 percent, then the number of trains of process equipment would be less. As a comparison, a UK study (Florin, 2009) reported that a 500MWe net electricity power plant would require 3.75 hectares of empty land for CO_2 capture and compression.

Figure 4-11 Estimated site area needs for capture at power plants



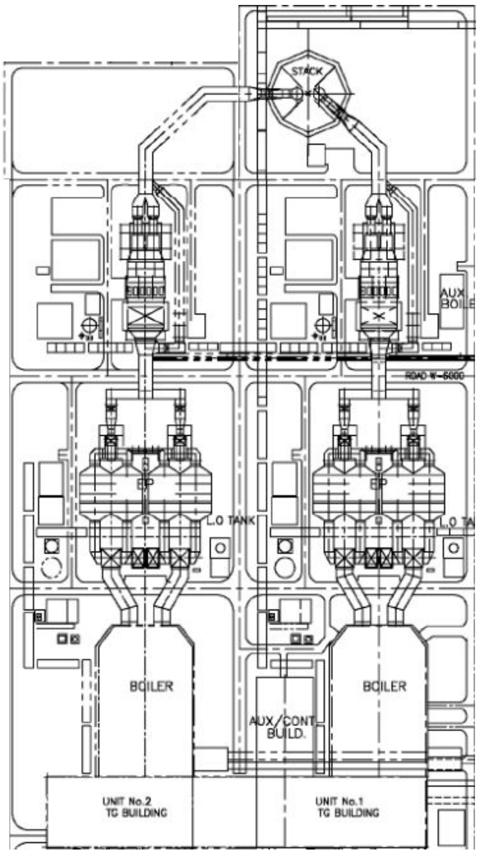
The West Java power plant with 2x1000 MWe output would require approximately six hectares of additional land for CO_2 capture facilities. A revised layout for a typical power plant, with space for CCS-Readiness at 90 percent CO_2 capture, is presented in Figure 4-12.

Figure 4-12 A typical 2x1000 MWe CCS-R Site Area Arrangement

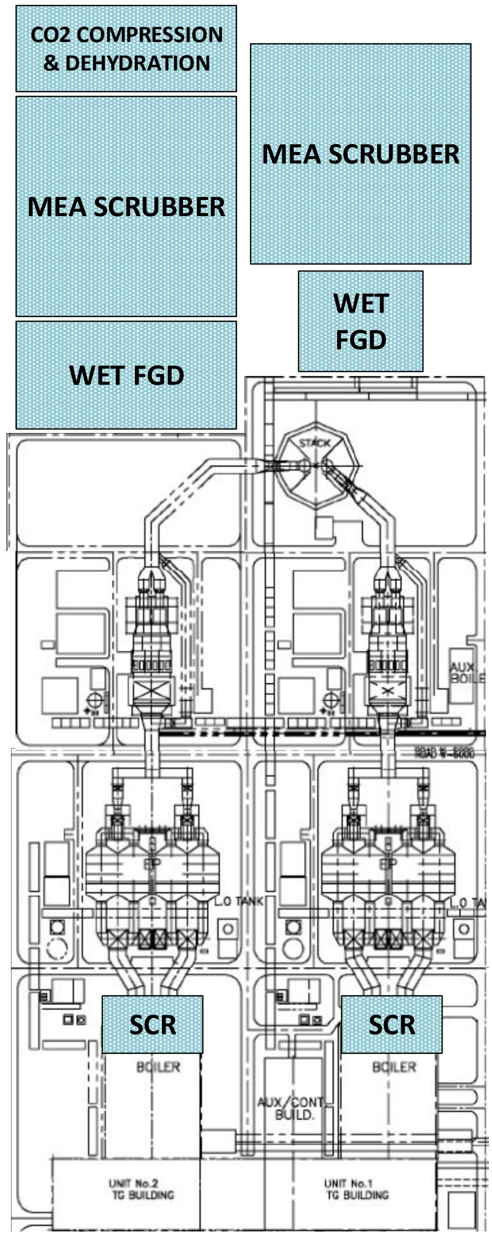
Section	Area Requirement (ha)
FGD	1.3
MEA Scrubber	3.8
CO_2 Compression	0.9
Total	6.0

LEGEND

: Retrofit Equipment



Without CCS



With CCS

4.4.5 CCS-Readiness costs

The principal up-front cost of making a power plant CCS-Ready would be the purchase of additional land to accommodate the extra equipment in the future. However, in the case of the subject West Java power plant, the site is large enough to accommodate future CO_2 capture equipment without the need for additional land acquisition. The cost of land is site-specific.

No significant additional equipment would be required for the power plant to be CO_2 capture-ready. However, planning and design effort would need to take account of the potential for CCS to be retrofitted at a later stage. That design effort could incur project management costs over and above the normal design and management requirements for replicating a standard power plant design.

However, the direct CCS-readiness costs will be minor and, aside from land acquisition costs, might be accommodated within the project contingency budgeting for a large power plant investment.

5. TRANSPORT STUDY

5.1 Objectives of the transport study

- To identify possible pipeline routes and distribution networks from the power plants to the CO_2 storage locations;
- To determine the lengths and diameters of CO_2 delivery pipelines; and
- To determine costs of CO_2 transport networks.

5.2 CO_2 transport – pipeline design principles

The transport of CO_2 considered in this study involves the delivery of up to 10.92 million tonnes per year from the West Java power plant, and up to 3.78 million tonnes per year of CO_2 from South Sumatra power plant, to CO_2 storage areas. CO_2 can be transported at small scale as a liquid in high-pressure containers at low temperature, by road, rail or ship, as in the Gundih pilot project in Central Java. However, at the large scale of CCS operation, the use of pipelines is the only viable technology.

For pipeline transport of CO_2 it is important that the vapour phase should be avoided because the much lower density of CO_2 vapour would increase pressure drops; also, vapour lock problems might be encountered in a pipeline network. The CO_2 in a long distance pipeline will be at ambient temperature, which is typically 25-30°C in Indonesia (i.e., near to the CO_2 critical temperature of 31°C). Therefore, the pressure of CO_2 in the pipeline should be maintained above the CO_2 critical pressure of 74 bar to ensure that formation of vapor phase in the pipelines is avoided, so a minimum pressure of 80 bar is used as a pipeline design criterion.

The CO_2 would be compressed at the power plants site to 110 bar. The CO_2 pipelines can either be designed with a large diameter, low velocity and low pressure drop -- so that recompression is not required -- or they can be designed with a smaller diameter, higher velocity and higher pressure drop requiring recompression stations. The latter approach is usually adopted for natural gas pipelines, which have a ready supply of energy for remote recompression stations.

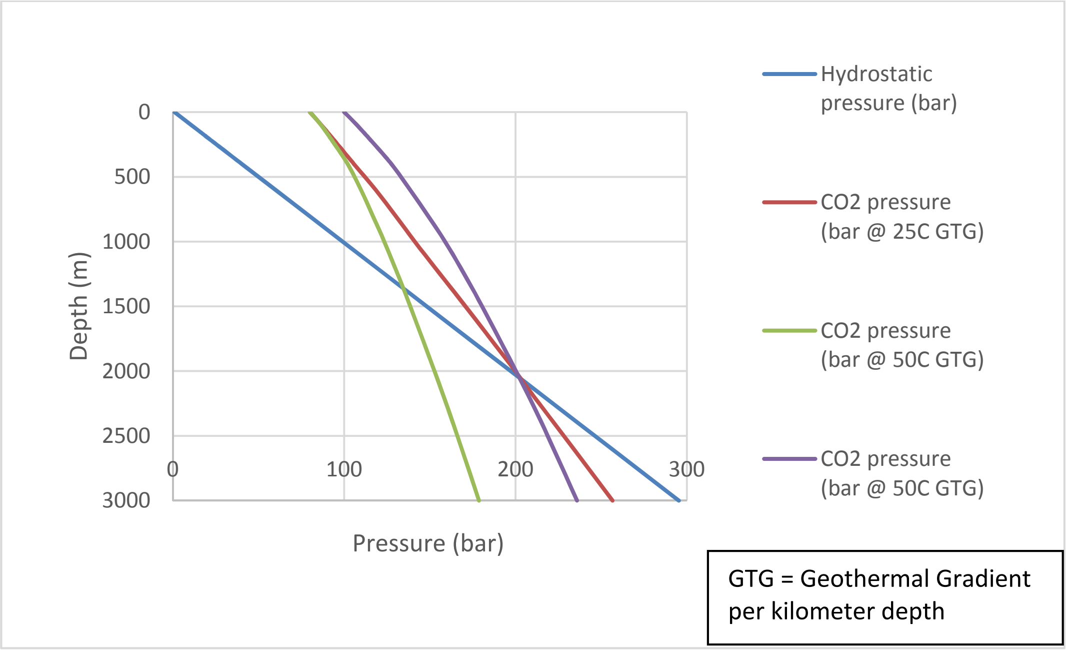
In this study, pipeline sizing has been based on the former approach so that CO_2 is delivered to the storage locations at above its critical pressure and without recompression. In the context of CCS for CO_2 emission control, avoidance of auxiliary energy consumption is desirable. Also, from a practical perspective, the avoidance of arranging an energy supply to a remote pipeline compressor station is also desirable.

5.2.1 Underground pressure considerations

Since the liquid CO_2 would be delivered to the injection site at a pressure in excess of 80 bar, that delivered pressure would generally provide adequate driving force for CO_2 injection, so additional compression at the well site should not normally be required.

The formation pressure at depth in the well might be greater than 80 bar due to the groundwater hydrostatic pressure. However, the input pressure plus the vertical pressure head of CO_2 in the well would normally overcome that pressure unless the geothermal gradient is high. Figure 5-1 shows a comparison of the hydrostatic pressure in a well with the increasing pressure of CO_2 with depth, based on surface injection conditions of 80 bar and 100 bar at 30°C.

Figure 5-1 Comparison of CO_2 pressure with hydrostatic pressure at depth



If the geothermal gradient is 25°C/km (degrees Celsius per kilometre depth) then injected supercritical CO_2 would have a relative density[14] ranging from 0.56 to 0.6 below 600m deep, which indicates that under these conditions booster pumps at the well head would not be required until the depth exceeds about 2000 meters. However, if the geothermal gradient is 50°C/km, as is typical in South Sumatra and West Java, then the injected CO_2 would have a subsurface density of 0.25 to 0.35 gm/cm^3. Under these warmer conditions, this indicates that booster pumps at the well head would be required if the depth exceeds about 1400 meters.

Figure 5-1 also shows that, at the local geothermal gradient of 50°C/km, if the delivered CO_2 pressure is 100 bar at the well head, then that would be sufficient to deliver CO_2 to about 2000 meters depth. However, the actual pressure balance will depend on the actual down-hole temperature and pressure conditions encountered.

5.2.2 Design and costing for a single CO_2 transmission pipeline

As determined in Section 6, a suitable CO_2 storage location for 10.9 million tonnes per year of CO_2 from the West Java plant would be almost all in on-shore West Java gas fields to the east of the power plant. Design parameters for a bulk CO_2 transmission pipeline to that storage area are shown in Table 5-1.

This sample calculation below is based on a 175-kilometer pipe with a low velocity, low pressure drop and no recompression. It would require a 34-inch diameter pipe for the CO_2 from

[14] Density relative to water

the reference case. A similar CO_2 pipeline described (NETL, 2014) for a higher CO_2 velocity uses a smaller 24-inch diameter pipeline, with higher pressure drops and requiring two recompression pumps for 300 kilometres of CO_2 transmission.

Table 5-1 CO_2 transmission pipeline calculations

Parameter	value	units
Pipeline length	175	km
Pipe diameter	34	inches
Maximum design CO_2 flowrate (@ 80% capacity factor)	1558	tonnes/hr
Inlet pressure	110	bar
Outlet pressure	101	bar
Ambient temperature	27	^oC
Liquid CO_2 density (@ 105.5 bar and 27^{o}C)	804.6	kg/m^3
CO_2 velocity in pipeline	0.736	meters per second (m/sec)
Pipeline wall thickness	79.1	millimetres (mm)
Pipeline weight (@ steel density 7.85 gm/cm^3)	2.25	tonnes/m
Piping material cost (@ US$200/ton)	78.6	US$ millions
Pipe welding cost (@ US$100/inch per 10 meters spacing)	66.5	US$ millions
Overheads for materials and welding (@ 40%	58.04	US$ millions
Total Erected Cost	203.1	US$ millions
Total Installed cost (add 30% management and contingency)	264	US$ millions
Pipeline cost factor (2014 basis)	39,700	US$/km-inch

The pipeline design calculations shown in Table 5-1 indicate a nominal baseline total installed cost of US$40,000 per km-inch (kilometres length multiplied by inches of inside diameter). That factor is the same as the McCoy rule of thumb (NETL, 2014) for an 80 km pipeline in flat dry terrain. CO_2 transportation costs would be higher in mountainous, marshy or built up areas. Also, the cost per kilometre would be higher for shorter pipelines. For this outline analysis of pipeline costs, a terrain and length factor of 25 percent is added. Various literature sources suggest that off-shore pipeline costs are typically about double the base cost of equivalent on-shore pipelines, and literature (NETL, 2014) also suggests a much higher cost for deep sub-sea pipelines. However, the sea north of Java is very shallow so pipe laying will be straightforward. LEMIGAS proposes a cost of US$75,000 per km-inch for off-shore pipelines in the Java Sea. For the purpose of this assessment, pipeline total investment costs are taken as US$50,000 per km-inch for on-shore pipelines and US$75,000 per km-inch for off-shore CO_2 transmission and distribution pipelines in the shallow Java Sea.

5.2.3 Using the pipeline for CO_2 buffer storage

The CO_2 transmission pipeline is effectively a large pressure vessel with some capacity to accommodate fluctuations in the inputs and outputs of CO_2. Natural gas transmission systems use this feature, known as "linepack," to help to match supply and demand. In the case of a liquid CO_2 transmission line, the ability to accommodate fluctuations in flow depends on the compressibility of liquid CO_2.

Considering the 175 km pipeline scenario presented in Table 5-1, the impact of an abrupt stop of input of CO_2 would be that the pressure at the pipe output end would gradually reduce. Figure 5-2 shows how quickly the delivered pressure would reduce in the event of stopping CO_2 production.

Figure 5-2 Transmission pipe outlet pressure reduction profile when supply stops

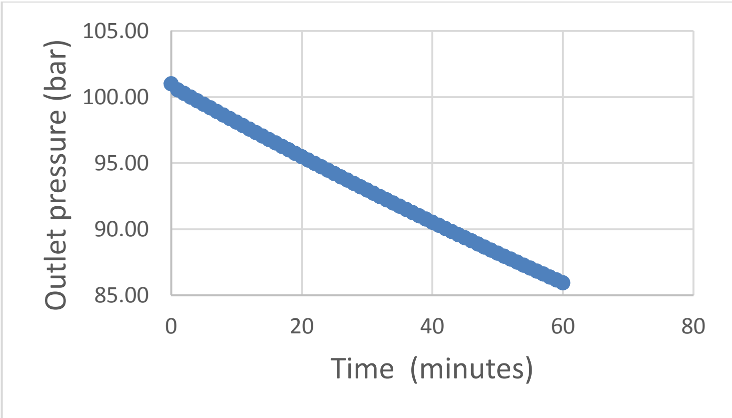


Figure 5-2 relates to a pipeline that is 175 km long. This analysis indicates that if the supply of CO_2 at the West Java power plant stops, there would be about one hour for system operators to take corresponding action at the delivery end of a 175 km pipeline. The length of time that adequate delivery pressure would be sustained will be proportional to the pipeline length. In the case of CO_2 delivery to closer off-shore gas fields in West Java, the delay between stopping of CO_2 production and the stopping of CO_2 injection would be less than one hour. In the case of capture and storage via shorter pipelines in South Sumatra, the time delay would be even shorter.

In the case of the concept of a 416 km pipeline delivering CO_2 from West Java to South Sumatra for EOR, the CO_2 storage capacity in the pipeline would be able to accommodate a power plant outage up to about two hours duration before the EOR operation was impacted. However, that storage concept is dismissed in Chapter 7.

5.3 CO_2 transmission and distribution networks

5.3.1 West Java CO_2 Storage in on-shore gas fields in West Java

The implementation of 90 percent CO_2 capture at the West Java power plant would require capacity to store 10.92 million tonnes per year of CO_2. If CCS were to be implemented five years after commissioning the power plant, then it would operate for the next 20 years of the initial 25 years of power plant design lifetime. Accordingly, identified storage for up to 218 million tonnes of CO_2 would be required to meet the CCS-ready storage criterion for the cases evaluated.

Figure 5-3 shows the relative locations of the West Java power plant and onshore natural gas fields in Northwest Java. Analysis presented in Chapter 6 identifies that the 17 on-shore gas fields shown on Figure 5-3 only have enough capacity to store 164 million tonnes of CO_2. Therefore about half of the CO_2 storage capacity of the largest off-shore gas field has been included in the assessment of on-shore CO_2 storage of the CO_2 captured in West Java.

The locations of existing gas gathering pipelines are also shown on this diagram. For on-shore CO_2 pipelines, the routes are assumed to follow these existing pipeline corridors.

Figure 5-3 West Java Power plant location relative to on-shore gas fields

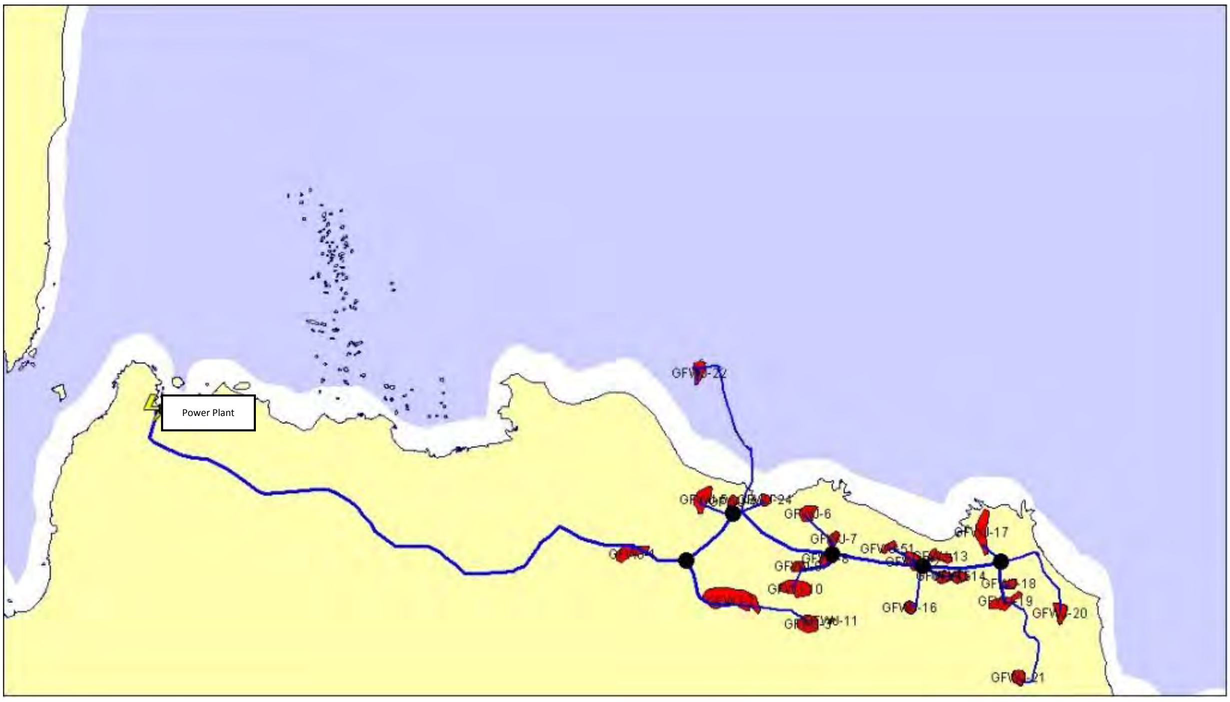
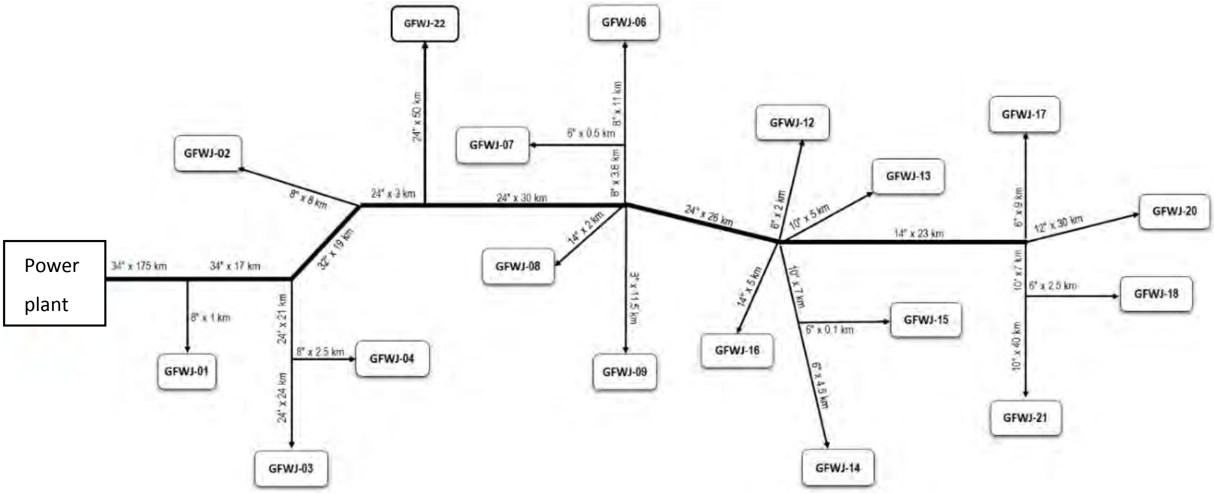


Figure 5-4 shows a pipeline network to deliver CO_2 to these gas fields. The long CO_2 transmission line from the power plant to the first off take point is a 34-inch diameter pipeline that is 175 kilometers long, which is the subject of the sample calculation presented in Table 5-1.

The overall transmission pipeline would be 293 km long, initially at 34 inch diameter and reducing progressively to 14-inch diameter, with smaller pipes branching to the gas fields. In total, over 500km of pipeline would be required in the transmission and distribution network for on-shore gas field storage in West Java, shown in Figure 5-4.

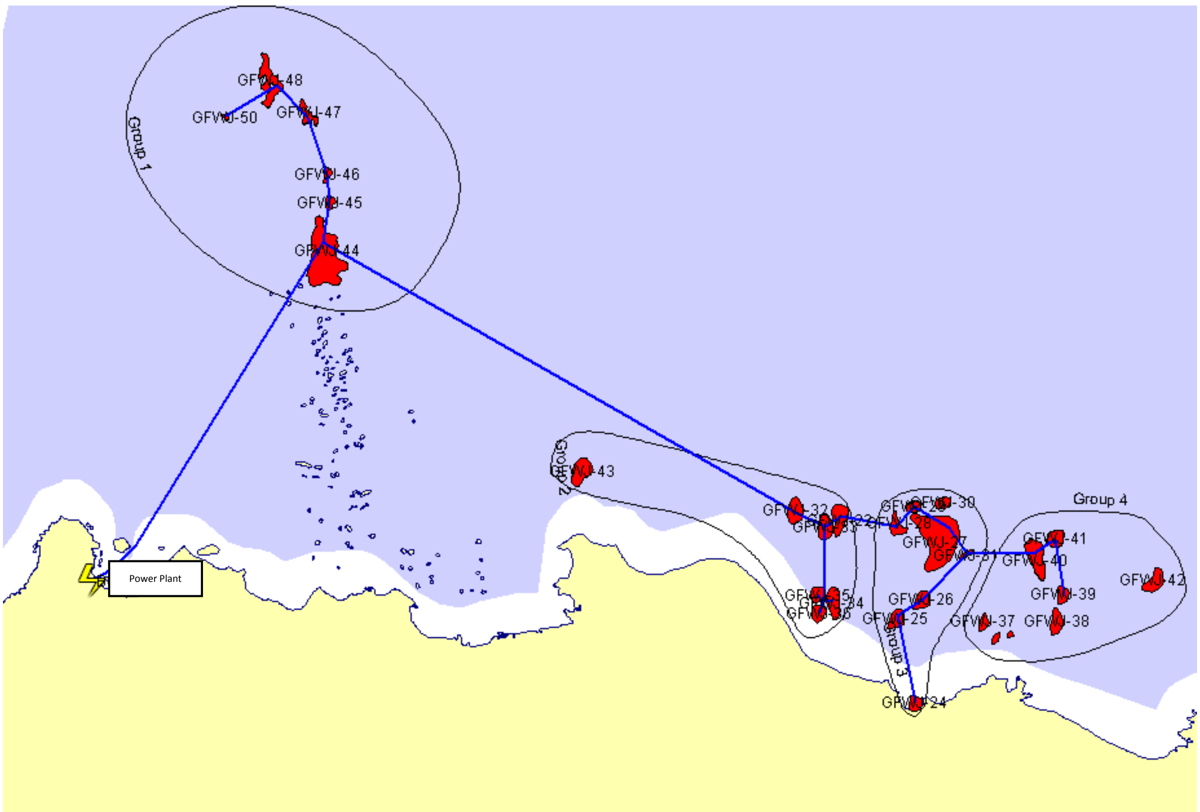
Figure 5-4 Distribution of CO_2 to on-shore gas fields in West Java



5.3.2 CO_2 Storage in off-shore gas fields in West Java

In the UK, the CCS storage-ready criterion includes the requirement that storage must be off-shore. That requirement is partly due to plentiful off-shore CO_2 storage capacity in the UK and partly due to concern over the perceived risks and public acceptability of CO_2 storage on-shore. Accordingly, a second storage option for CO_2 storage in West Java is assessed comprising CO_2 storage only in off-shore gas fields.

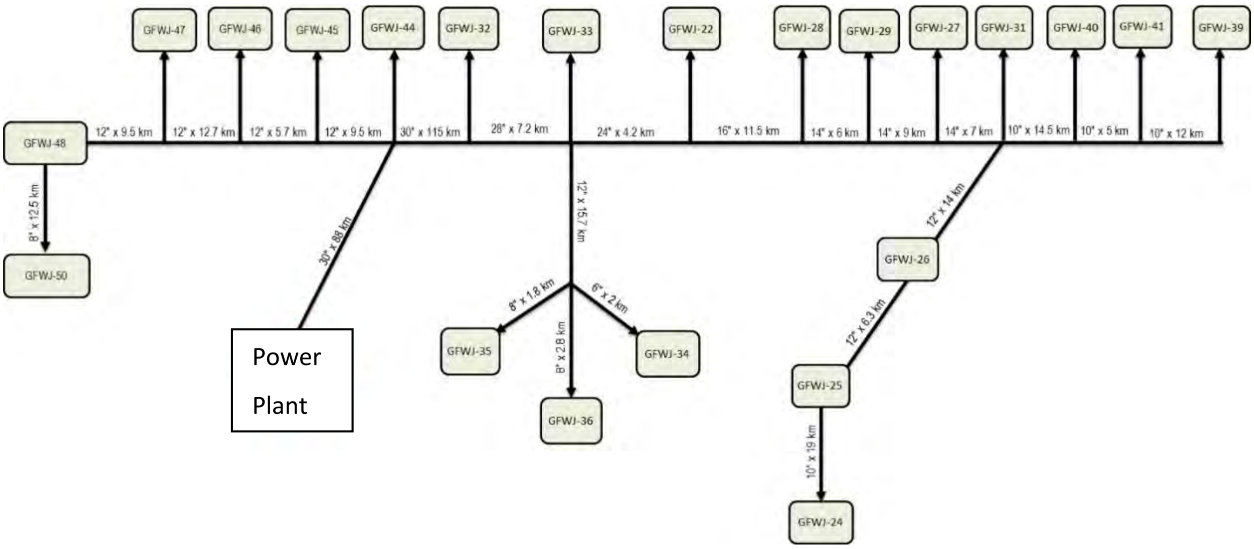
Figure 5-5 West Java Power plant location relative to off-shore gas fields



The review of storage options detailed in Chapter 6 has identified sufficient storage in off-shore gas fields to accommodate all of the 218 million tonnes of CO_2 that would be produced from the West Java power plant at 90 percent capture over 20 years.

Figure 5-5 shows the relative locations of the West Java power plant and offshore natural gas fields north of Java. The existing gas gathering pipelines do not provide direct routes from the power plant to off-shore fields, particularly the fields north of the power plant. Instead, for the pipeline network, a direct line from the power plant to the nearest off-shore gas fields is assumed, with the line to the other more eastern gas fields following the gas gathering pipeline routes. The first off-shore CO_2 transmission pipe would be 88 km long with 30-inch diameter. The subsequent distribution pipes would have a total length of 303 km with an average diameter of 19 inches. Figure 5-6 shows the pipeline distribution scheme to off-shore gas fields in West Java.

Figure 5-6 Pipeline distribution network to off-shore gas fields in West Java



An important consideration of CO_2 storage in off-shore gas fields is that any leakage of CO_2 would be into the sea and not into the atmosphere. The seawater overlying off-shore gas fields of Northwest Java is typically less than 30 meters deep. Small quantities of CO_2 seeping slowly into the shallow seawater would dissolve and would not be released to the atmosphere, thus achieving the CO_2 retention objectives of CCS. Fossil fuel CO_2 released to the atmosphere slowly dissolves in the surface seawater at the rate of about 1 percent per year. Therefore, if leakage from subsea gas field storage into the surface water is at a lower rate than 1 percent per year, it would have a lesser seawater acidification effect than if the CO_2 is released into the atmosphere.

5.3.3 West Java CO_2 storage via EOR in South Sumatra

There are no significant EOR opportunities in West Java, so the possibility of piping CO_2 from West Java to be used for EOR in the oil fields in South Sumatra has been considered. Analysis in Chapter 7 concludes that, due to the limited demand for CO_2 for EOR and the uneven demand profile for EOR over time, the accommodation of all the CO_2 from West Java in the EOR market in South Sumatra is not a viable option as a basis for CCS. Notwithstanding that conclusion, the feasibility and cost of the delivery of 218 million tonnes of CO_2 over 20 years from West Java to the oil fields of South Sumatra has been evaluated for completeness.

A 416 km long transmission pipeline would be required to the first distribution hub (H1) in South Sumatra, which would include a 100 km long off-shore section. The CO_2 transmission pipeline would follow the existing route of a natural gas transmission pipeline. Figure 5-7 illustrates this concept (note: the distance of 356 km on this diagram is the distance to the nearest oil field -- not to H1).

The 416 km CO_2 transmission pipeline would have the same maximum duty as the 175 km CO_2 transmission pipeline assessed in Table 5-1. For the 90 percent CO_2 capture case, it would require a 36-inch diameter pipe, and the outlet pressure at Hub 1 would be 90 bar instead of 101 bar. Therefore, some recompression may be required to deliver the CO_2 through the subsequent CO_2 distribution network.

The 36-inch transmission pipeline would comprise 100 km offshore and 316 km onshore length. Therefore, the estimated transmission pipeline capital cost, using the factors developed in Section 5.3, would be US$837 million to deliver 218 million tonnes of CO_2 from 90 percent capture in West Java to H1 in the South Sumatra oil field basin.

Figure 5-7 CO_2 transmission pipeline concept - West Java to EOR in South Sumatra

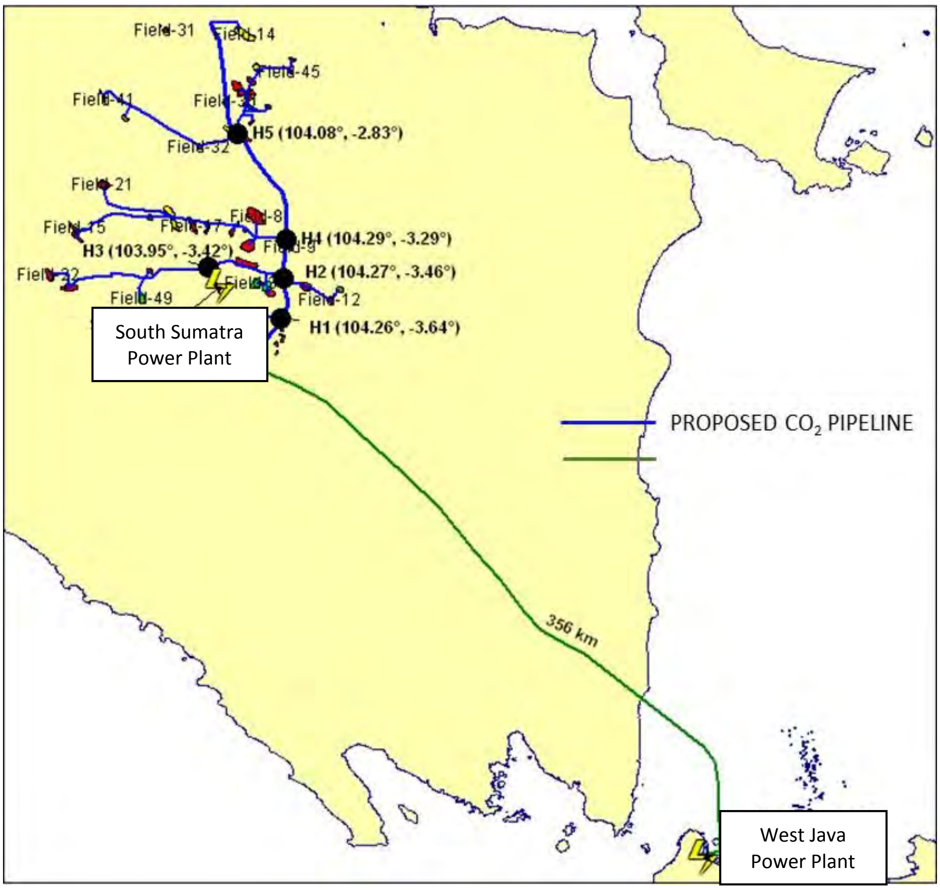


Figure 5-7 indicates that the delivery of CO_2 at 90 bar from West Java to Hub 1, would be about equivalent to the delivery of CO_2 from the South Sumatra power plant at 110 bar directly into the local CO_2 distribution network. Therefore, if the cost of a booster pump to compress the CO_2 transmitted from West Java from 90 bar to 110 bar is added to the transmission line capital cost estimate it would provide a basis for assessing the marginal cost difference between CO_2 supplied for EOR from the two power plants in South Sumatra and West Java.

CO_2 booster pumps are sized and costed according to the power that they consume. The energy gain by the CO_2 is proportional to the mass flow of CO_2 and the pressure head increase. The mass flow of CO_2 would be 1558 tonnes per hour. The density of CO_2 at 100 bar and 27°C is 0.8 kg/m^3, so the pressure head increase from 90 bar to 110 bar would be 160 meters. If the energy efficiency of the CO_2 pump is 50 percent, then to pump the total liquid CO_2 in West Java from 90 bar to 110 bar would require 1.38 MW (i.e., an additional one percentage point on the CCS energy penalty). The cost of a booster pump is estimated at US$2000 per horsepower (HP, which equals 746 Watts) (i.e., US$2700/kW). Therefore, the capital cost of pumps for this duty would be about US$3.7 million plus operating costs.

Table 5-2 shows an estimation of the capital cost of a conceptual 416 km pipeline from the West Java Power Plant to the first CO_2 distribution hub in South Sumatra.

Table 5-2 Pipeline costs for inter-island CO_2 transmission over 20 years

CO_2 capture fraction	CO_2 flow tonnes/hr	Pipeline diameter (inches)	Offshore pipe cost for 100km (US$ mln)	Onshore pipe cost for 316km (US$ mln)	CO_2 booster pump (US$ mln)	Total transmission capital cost (US$ mln)
90%	1558	36	253	580	4	837
45%	779	26	183	451	2	636
22.5%	390	18	127	290	1	418

These costs are based on the supply of CO_2 at a steady rate for 20 years. EOR requires a large amount of CO_2 initially, declining in later years. If the demand for CO_2 for EOR is not sustained, then the economics of transmitting it from West Java would be worse.

5.3.4 South Sumatra CO_2 storage in gas fields

The implementation of 90 percent CO_2 capture at the South Sumatra power plant would require capacity to store 3.7 million tonnes per year of CO_2. If CCS were to be implemented five years after commissioning the power plant, then it would operate for the next 20 years of the initial 25 years of power plant design lifetime. Accordingly, identified storage for 74 million tonnes of CO_2 would be required to meet the CCS-ready storage criterion.

The review of storage options detailed in Chapter 6 has not found a single storage location with adequate capacity for 74 million tonnes of CO_2. However, sufficient storage has been identified in six depleted gas onshore natural gas fields in South Sumatra, listed in Table 5-3.

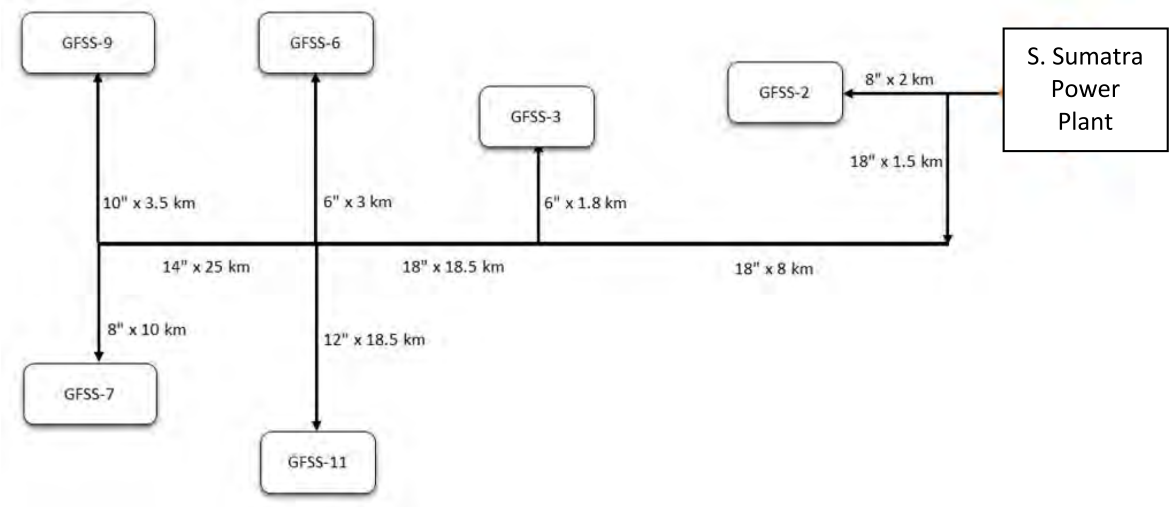
Table 5-3 **Natural gas field data for CO_2 storage in South Sumatra**

Gas field	Depth of formation (meters)	Natural gas production (BSCF)[1]	Year available for CO_2 storage	CO_2 storage (million tonnes CO_2)	Flow rate at 80% capacity (MMscfd)[2]	Distance from power plant (km)
GFSS-2	1720	267	2009	13.7	44.2	15.0
GFSS-3	1720	812	2032	41.7	135	13.5
GFSS-6	1160	497	2017	24.4	82.1	25.7
GFSS-7	1720	183	2022	9.4	30.2	29.0
GFSS-9	1720	348	2014	17.8	57.5	47.0
GFSS-11	970	259	2024	13.3	42.8	53.7

Notes: [1] BSCF is billion standard cubic feet (scf); [2] MMscfd is million standard cubic feet per day.

The largest of these gas fields (GFSS3) would not be depleted and available for storage until 2032. Table 5-3 lists the natural gas production data and consequent CO_2 storage capacity data for these six gas wells. Figure 5-8 shows a scheme for the transport of CO_2 by pipeline to these eight storage locations. The total pipeline length is 92 km and the average diameter is 13.5 inches

Figure 5-8 Distribution of CO_2 from South Sumatra power plant to onshore gas fields



5.3.5 South Sumatra CO_2 storage in oil fields via EOR

An economically preferred storage location would be in depleted oil fields in the South Sumatra basin, with the possibility of revenue from sales of CO_2 for EOR, as discussed in Chapter 7. A potential demand for 243 million tonnes of CO_2 for EOR in 127 oil fields has been identified in South Sumatra over the period to 2045. Figure 5.9 shows an overall plan for a CO_2 distribution network for EOR in South Sumatra.

Figure 5-9 CO_2 supply pipeline network for 127 oil fields in South Sumatra

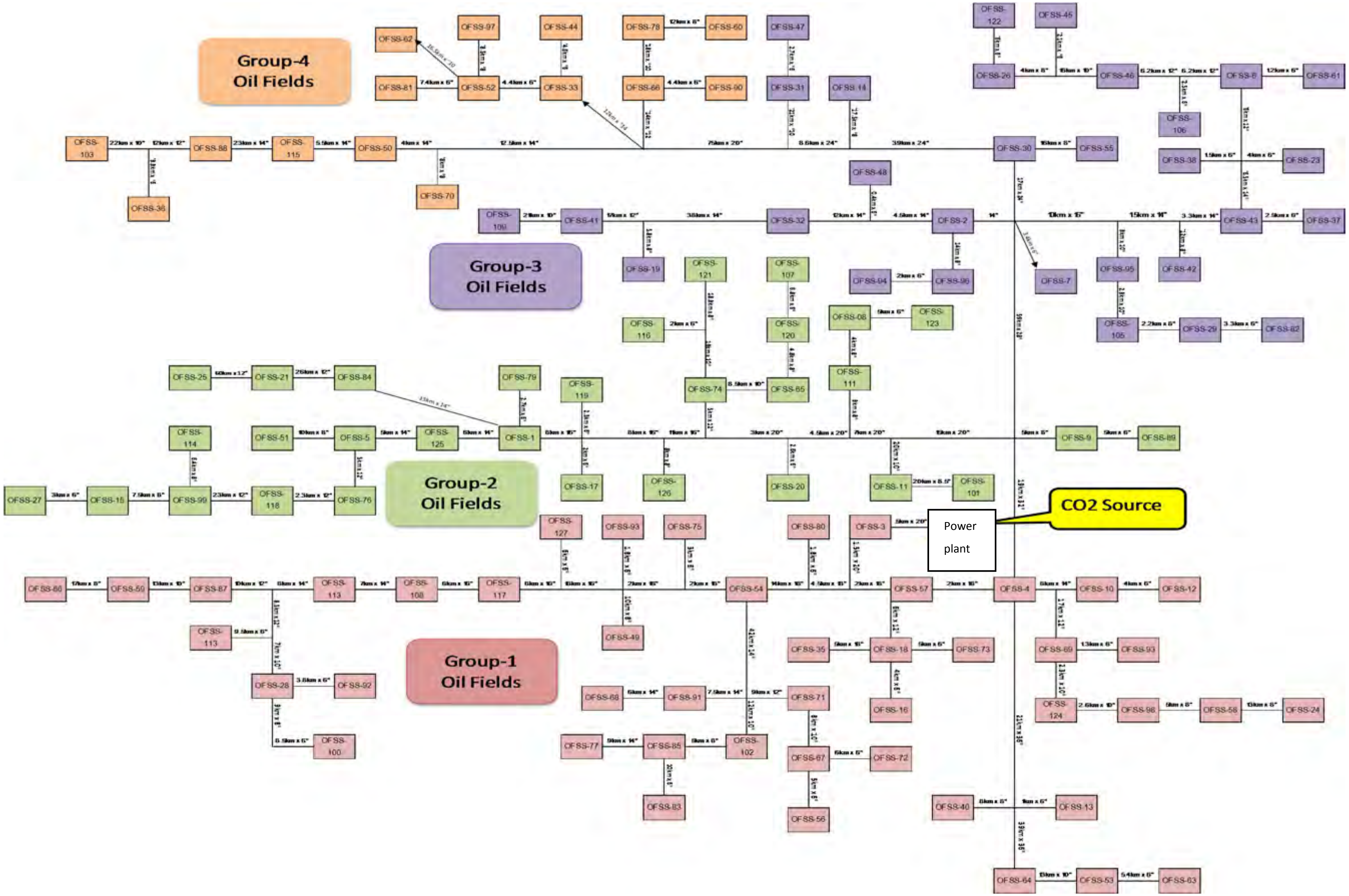


Table 5-4 CO_2 delivery pipeline capital cost assessment for 20 years of utilization

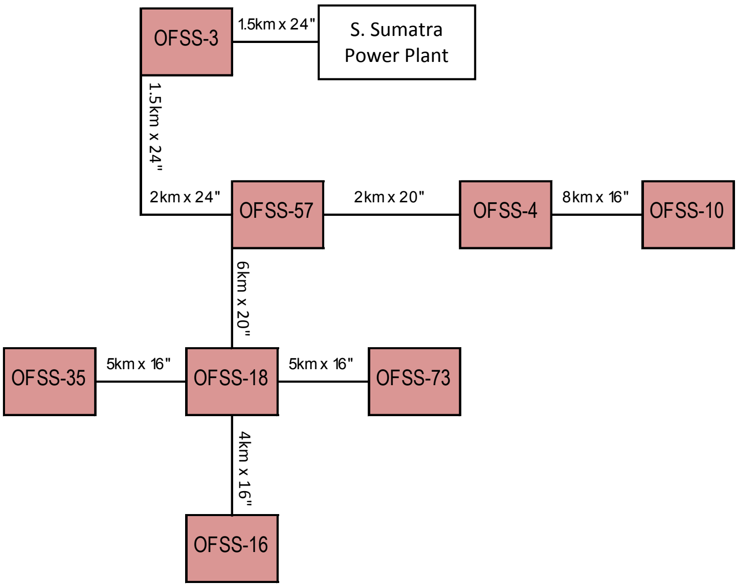
CO_2 pipeline networks cost assessment	West Java power plant to gas fields in West Java		South Sumatra power plant to gas or oil fields in South Sumatra		West Java to South Sumatra
CO_2 storage scenario	On-shore	Off-shore	Gas Fields	EOR[1]	EOR[2]
CO_2 delivery (million tonnes/year)	10.9	10.9	3.7	2.0	10.9
Transmission pipe length (km)	175[3]	88			416[4]
Transmission pipe diameter (inches)	34	30			36
Transmission pipe cost (US$ mln)	298[5]	198[6]			837
Number of storage locations	18	22	6	8	~100+
Distrib. pipes on-shore total (km)	323		92	49	370
Distrib. pipes off-shore total (km)	42	303[7]			
On shore average diameter (inches)	17.4		13.5	20	16
Off-shore average diameter (inches)	24	19.1			
Distrib. pipes on-shore cost (US$ mln)	282		62	48	296
Distrib. pipes off-shore cost (US$ mln)	76	433			
Total pipeline cost (US$ million)[8]	**655**	**631**	**62**	**48**	**1,133**
CO_2 delivered over 20 years (million tonnes)	218	218	74	41	218

Notes: [1] Assuming exclusive supply to eight oil fields for EOR in south east corner of South Sumatra oil province; [2] Assuming short term demand for CO_2 for EOR – Non-viable case assessed for completeness; [3] First section of transmission line to first offtake; [4] Long distance pipeline including subsea section between West Java and South Sumatra; [5] At US$50,000 per km-inch; [6] At US$75,000 per km-inch; [7] Based on direct off-shore lines to clusters of gas fields instead of following the gas gathering lines; [8] Total capital cost in present day values before discounting.

Analysis presented in Chapter 7 identifies that sources of by-product CO_2 available in South Sumatra would be able to meet all this demand over time, but that use of half to two thirds of the CO_2 from the South Sumatra power plant could enable the exploitation of some EOR to be brought forward by about 15 years.

The actual contribution of CO_2 from the power plant to specific EOR locations would depend on timing and other factors. However, for the purpose of transport cost assessment, eight oil fields in the southeast quadrant of the South Sumatra basin have been identified as having the overall EOR demand to match more than half of the supply from the South Sumatra power plant. Distribution pipes to those oil fields would have a combined length of less than about 50 km and an average diameter of 20 inches, as illustrated in Figure 5-10.

Figure 5-10 Distribution network from S Sumatra power plant to oil fields for EOR



5.4 Cost of CO_2 transport options

Table 5-4 shows a summary of the capital cost calculations for transmission and distribution of CO_2 for the five cases assessed above. These calculations are based on 90 percent CO_2 capture for 20 years and use the pipeline costing factors of US$50,000 per km-inch for on-shore pipelines and US$75,000 per km-inch for off-shore pipelines, developed in Section 5.3.

These capital cost calculations, which have not been discounted, show that:

- The on-shore and off-shore storage options in gas fields for the CO_2 from West Java are similar in capital cost, because the higher cost of off-shore pipelines is offset by some off-shore gas fields being nearer to the power plant;
- The cost of delivering CO_2 from the South Sumatra power plant to gas field storage in South Sumatra is lower per tonne of CO_2 delivered than the cost of delivering CO_2 from West Java to gas field storage in West Java because:
  - No long-distance transmission pipeline is needed; and
  - The gas fields in South Sumatra are more closely spaced than in West Java; and
- Distribution of CO_2 to oil fields for EOR would require 3-4 times more CO_2 delivery locations than distribution to gas fields, and hence greater distribution pipeline costs.

6 STORAGE STUDY

"Underground accumulation of carbon dioxide (CO_2) is a widespread geological phenomenon, with natural trapping of CO_2 in underground reservoirs. Information and experience gained from the injection and/or storage of CO_2 from a large number of existing Enhanced Oil Recovery (EOR) and acid gas projects, as well as from the Sleipner, Weyburn and In Salah projects, indicate that it is feasible to store CO_2 in geological formations as a CO_2 mitigation option. Industrial analogues, including underground natural gas storage projects around the world and acid gas injection projects, provide additional indications that CO_2 can be safely injected and stored at well-characterized and properly managed sites. While there are differences between natural accumulations and engineered storage, injecting CO_2 into deep geological formations at carefully selected sites can store it underground for long periods of time: it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1000 years. Depleted oil and gas reservoirs, possibly coal formations and particularly saline formations (deep underground porous reservoir rocks saturated with brackish water or brine), can be used for storage of CO_2. At depths below about 800–1000 m, supercritical CO_2 has a liquid-like density that provides the potential for efficient utilization of underground storage space in the pores of sedimentary rocks. Carbon dioxide can remain trapped underground by virtue of a number of mechanisms, such as: trapping below an impermeable, confining layer (cap-rock); retention as an immobile phase trapped in the pore spaces of the storage formation; dissolution in the in situ formation fluids; and/or adsorption onto organic matter in coal and shale. Additionally, it may be trapped by reacting with the minerals in the storage formation and cap-rock to produce carbonate minerals. Models are available to predict what happens when CO_2 is injected underground. Also, by avoiding deteriorated wells or open fractures or faults, injected CO_2 will be retained for very long periods of time. Moreover, CO_2 becomes less mobile over time as a result of multiple trapping mechanisms, further lowering the prospect of leakage." (IPCC, 2005)

In this study the prospects of three categories of geological storage of CO_2 storage are considered:

- Supply of captured CO_2 for EOR activities in South Sumatra;
- Injection of CO_2 into the pore volume vacated by natural gas production; and
- Injection of CO_2 into deep saline aquifers.

The potential for storage of CO_2 in deep un-mineable coal seams with the displacement of coal bed methane has not been assessed, because it is not expected that suitable deep coal seams compatible with the permanent CO_2 storage criterion are available in West Java or South Sumatra and permanent retention of CO_2 in coal formations is questionable.

6.1 Objectives of the storage study

The objectives of the CO_2 storage component of the study are:

- To assess the potential capacity for geological CO_2 storage, including:
  - Potential demand for high-cost CO_2 for EOR, taking account of the availability of low-cost CO_2 from other sources;
  - Capacity for storage of CO_2 in depleted gas fields in South Sumatra;
  - Capacity for storage of CO_2 in depleted gas fields in West Java; and
  - Capacity for storage of CO_2 in deep aquifers.
- To determine economic implications of CO_2 storage in terms of:
  - Cost of preparation of gas fields for CO_2 injection; and
  - Cost of monitoring and verification of stored CO_2.

Additional details of the assessment of oil and gas well storage capacity carried out by LEMIGAS are presented in Annex 4.

6.2 Demand for CO_2 for EOR in South Sumatra

The potential market for CO_2 captured from power generation for EOR is discussed in detail in Chapter 7. In this section the background to EOR is discussed and the potential total CO_2 demand in South Sumatra is assessed.

An oil field is a geological formation from which liquid hydrocarbons (oil) can be pumped. There may also be a small amount of hydrocarbon gas produced with the oil. Water is also usually produced from an oil well. Production of oil by pumping continues until the yield of oil falls to the level where the pumping operation is no longer economic. At that point, a significant proportion of the Original Oil in Place (OOIP) still remains underground and various methods of enhancing the recovery of oil (EOR) are considered by the oil production company.

Fluids that might be injected into an oil field to enhance the recovery of oil include water, steam and CO_2. CO_2 is a particularly effective fluid for enhancing the recovery of oil from an oil field, because it mixes with the oil to reduce its viscosity, whereas other injected fluids such as water just displace the oil. The decision to carry out EOR and the timing of that decision is an economic decision for the oil field operator, which takes into account the specific circumstances of the field and the value of the additional oil that would be recovered. That economic decision sets the price that the oil field operator can afford to pay for CO_2. In the USA, prices of US$20-40 per tonne have reportedly been paid in some areas for CO_2 for EOR.

There are two mechanisms for CO_2-EOR, which depend on the nature of the oil field: immiscible EOR and miscible EOR. Immiscible EOR occurs where the injected CO_2 does not mix with the oil, but instead displaces the oil from the area where the CO_2 is injected and increases the pressure of the oil at the production wells so that it can be pumped out. Miscible

EOR occurs where the supercritical CO_2 mixes with the residual oil to make it less viscous and facilitating its flow to the production wells. In the case of miscible EOR, some of the CO_2 injected into the well would be produced back out of the well with the oil. Separation and reinjection of that CO_2 would be more economic for the oil company than buying new CO_2.

Every application of EOR will be case-specific. However, by using generic assumptions, the total demand for CO_2 for EOR can be estimated from oil well data. The generic assumptions are shown in Table 6-1 (IEAGHG, 2009) and (Taber, 1977).

Table 6-1 Assumptions of oil recovery factors and CO_2 requirements

	Immiscible	Miscible
Additional oil recoverable (% of original oil in place)	5%	12%
CO_2 required (tonnes per standard barrel of oil)	0.5	0.33

In West Java no significant oil fields have been identified with the potential for the use of CO_2 for EOR. In South Sumatra there is no CO_2-EOR practiced at present, but there is potential for large volumes of CO_2 to be used for EOR.

Screening was undertaken on all of the 127 oil fields in South Sumatra, of which 96 are identified as miscible and 31 as immiscible. That analysis has determined a total potential demand of 243 million tonnes of CO_2 for EOR. Of these oil fields, only 20 have a CO_2 demand of more than one million tonnes, comprising a total demand of 63.3 million tonnes of CO_2. The part of the total demand that might be met by CO_2 captured from power plants is determined in Chapter 7.

<u>CO_2 storage in oil wells without EOR</u>

When an oil well reaches the end of its productive life, after secondary and tertiary production, a significant proportion of the OOIP place will still remain underground. If such depleted oil wells were to be used for CO_2 storage without EOR infrastructure then there would be displacement of oily water in sub-economic quantities, which could be costly to deal with.

Furthermore, unrecovered oil in a depleted oil field may be considered as a potential asset for future exploitation in the event of a change in oil production economics or technology. If such depleted oil wells were to be used for CO_2 storage, then that residual oil would become inaccessible for future exploitation and it would become a stranded asset.

Accordingly, storage of CO_2 in depleted oil wells without EOR would not be attractive to oil well owners and is therefore not considered viable as a basis for CCS.

6.3 Potential CO_2 storage in depleted gas fields

When a natural gas well is exploited, the pressure in the well gradually declines until it reaches a low pressure at which production and processing of gas is no longer economic. At that point, the gas well is usually sealed and closed. The vacant gas storage volume is well defined by the quantity of gas that has been produced and the geological seal of the formation is indicated by the former presence of natural gas. Therefore, depleted gas fields are considered to be prime locations for the storage of captured CO_2.

A work-over of an old gas well would be required to ensure its integrity, but the ability to use existing wells means that drilling of new wells would probably be avoided. Long-term monitoring of the stored CO_2 would be required to ensure permanent retention of CO_2.

6.3.1 Relative CO_2 and natural gas volumes

The relative densities of CO_2 and natural gas depend on the pressures involved and on the geothermal gradient. A depleted gas field could store 1.4 to 2.4 molecules of supercritical CO_2 per molecule of natural gas previously in place, calculated as follows.

When the pressure of natural gas from a gas well drops to a low-value (in the region of 10 bar) and the flowrate of gas declines, then the gas well is closed in and usually sealed with a cement plug. When all the gas wells in a gas field have been exhausted and sealed, then that field becomes a resource for CO_2 storage.

CO_2 can be injected into a depleted gas well until the pressure is restored to the pressure of the original gas in place. Therefore the volume of CO_2 injected should be the same as the total volume of natural gas that has been produced over the life time of the field. Under storage conditions in a gas field, the CO_2 will be a supercritical fluid because the pressure will be above the critical pressure of CO_2 and, due to the geothermal gradient, the temperature of the CO_2 will be above the critical temperature. The CO_2 density and the density of the original gas will depend on the depth of the gas field.

Figure 6-1 Factors for calculation of CO_2 storage capacity in gas wells

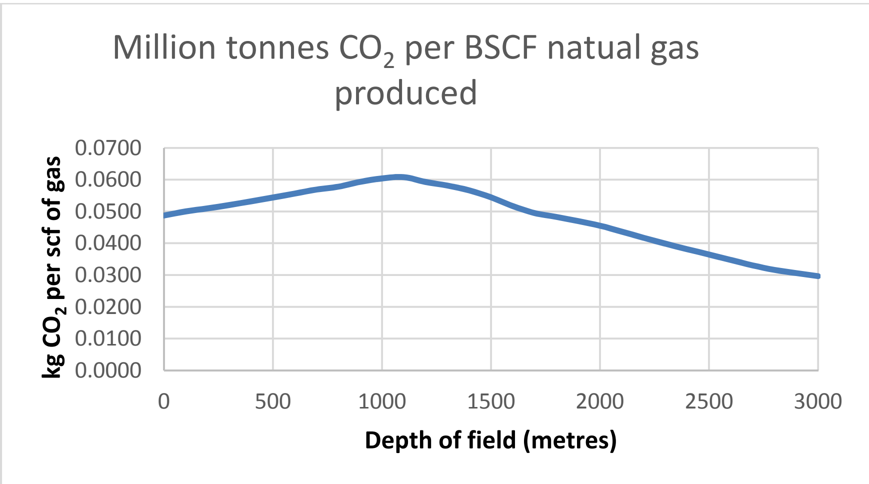


Figure 6.1 shows the mass of CO_2 that can potentially be stored in a depleted gas field as a function of the depth of the field. This chart is based on the following assumptions:

- The pressure in the field is equal to the hydrostatic head; and
- The geothermal gradient is 45°C per kilometer of depth, which is typical of conditions in South Sumatra.

Over the typical range of gas field depths from 500 meters to 2500 meters the average storage capacity factor is 0.0512 million tonnes of CO_2 per billion standard cubic feet (BSCF) of natural gas produced. This can be used as the default storage factor when the depth of a gas field is not known.

6.3.2 CO_2 storage capacity in gas fields in West Java and South Sumatra

LEMIGAS has carried out a survey of gas fields and has identified 51 gas fields in West Java and 45 gas field in South Sumatra with their expected total gas yield and their expected year of abandoning. From these data a cumulative gas field storage capacity curve has been compiled.

West Java

Figure 6-2 shows cumulative CO_2 storage curves for gas fields in West Java, which amounts to a total of 395 million tonnes of CO_2 storage available up to 2050. That CO_2 storage capacity comprises 224 million tonnes in 29 off-shore fields (of which 219 million tonnes of storage capacity is in 17 fields; each with more than 1 million tonnes of CO_2 storage capacity) plus 171 million tonnes in 22 on-shore fields (of which 167 million tonnes of storage capacity is in 16 fields; each with more than 1 million tonnes of CO_2 storage capacity)

Also shown on Figure 6-2 is the maximum production of CO_2 from the West Java power plant assuming that CCS is implemented on both units at 90 percent capture from 2025 to the end of the design life of the power plant in 2045.

Figure 6-2 Supply and demand for CO_2 gas field storage in West Java

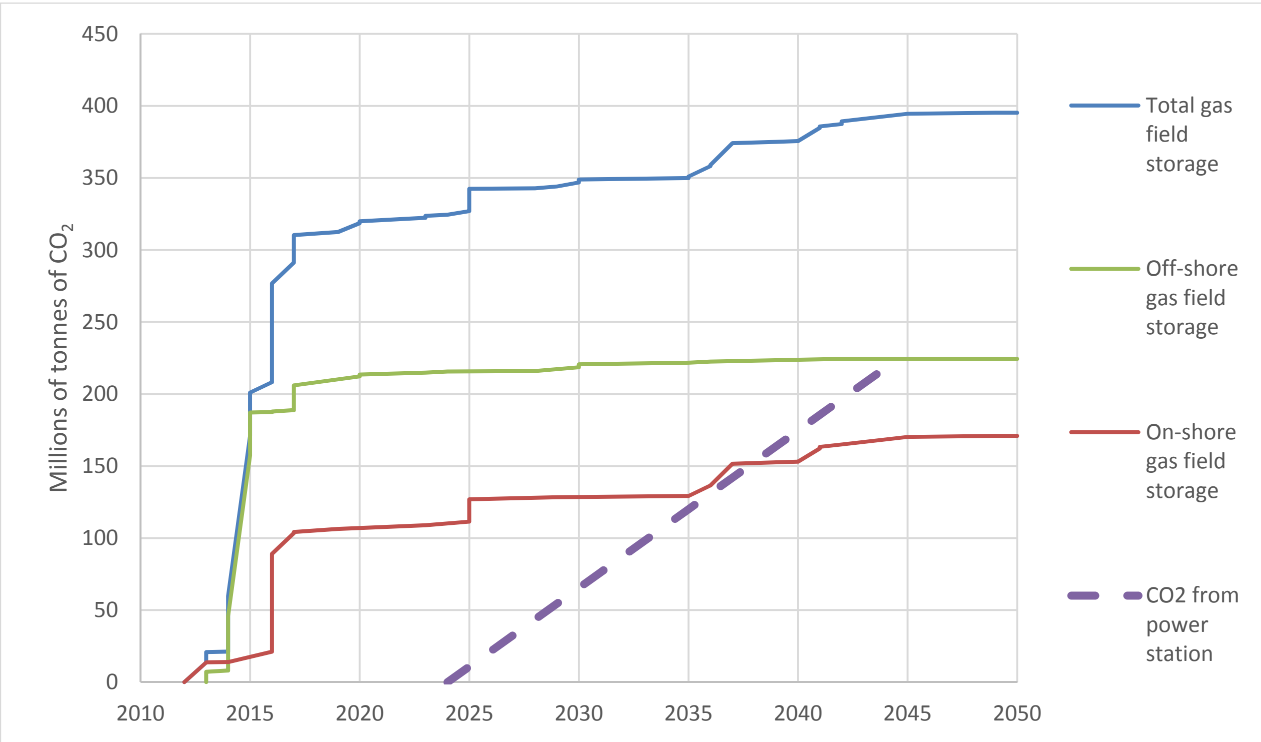


Figure 6-2 shows that CO_2 storage in gas fields in West Java is adequate to meet the needs of the West Java power plant under the conditions of the greatest CO_2 production scenario.

Therefore, this provides the storage element for definition of CCS-ready status for the West Java power plant.

Figure 6-2 shows that the subject reference CCS scenario for West Java would use all the storage capacity of off-shore gas fields. There would then be some further CO_2 storage capacity for CO_2 on shore with capacity for CO_2 from other power plants in West Java, or for a 16 year life extension of the subject West Java power plant.

<u>South Sumatra</u>

Figure 6-3 shows the cumulative storage curve for gas fields in South Sumatra, which amounts to 537 million tonnes of CO_2 storage available in 45 fields up to 2050. Of that CO_2 storage capacity, 531 million tonnes is located in 32 larger fields, predominantly more distant fields to the north. Also shown on Figure 6-3 is the maximum production of CO_2 from the South Sumatra power plant assuming that CCS is implemented at 90 percent capture from 2027 to the end of the design life of the power plant in 2047.

Figure 6-3 Supply and demand for gas field CO_2 storage in South Sumatra

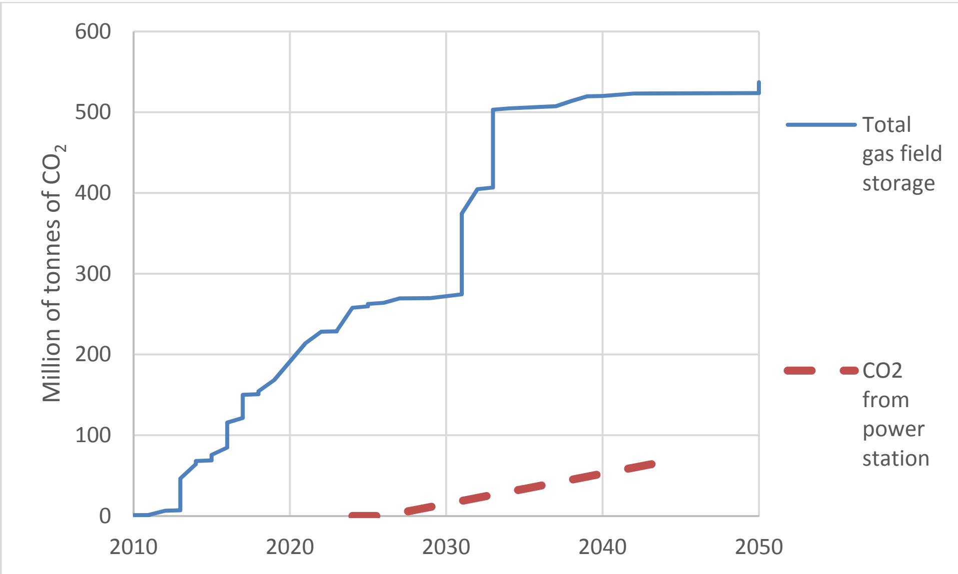


Figure 6-3 shows that CO_2 storage in gas fields in South Sumatra is easily adequate to meet the needs of the subject South Sumatra power plant under the conditions of the greatest CO_2 production scenario. Therefore, this provides the storage element for definition of CCS-ready status for the South Sumatra power plant.

There would be sufficient additional CO_2 storage capacity in South Sumatra gas fields for a 20 year life extension of the nominal 600 MW South Sumatra power plant at 90 percent capture plus a further 2500 nominal MW of coal-fired power generation with 90 percent CO_2 capture for 25 years, which would actually yield a net 1750 MW with CCS implemented.

6.4 Potential CO_2 storage in deep saline aquifers

6.4.1 Principles of aquifer storage of CO_2

Annex 5 presents a detailed review carried out by LEMIGAS of the geology of South Sumatra and West Java. Prospects for locations suitable for CO_2 storage in deep saline aquifers require a porous formation overlaid by an impervious cap-rock formation. Some potentially suitable pairings of formations have been identified for further study, and likely volumetric capacities have been estimated.

A recent international review of potential storage capacities in deep saline aquifers (IEAGHG, 2014) presents a comparison of volumetric and dynamic storage resource estimation methods for deep saline formations. This report identifies that very long time frames (e.g., out to 500 years) might be required for the capacity determined by volumetric analysis to be filled with CO_2 when the dynamics of CO_2 injection into deep aquifers is taken into account. This report also suggests that potential storage capacity in deep saline aquifers could be a small fraction of the theoretical volume based on the area and thickness of formations, when the dynamics of CO_2 injection is taken into account over the relatively short timeframe of the life of a power plant.

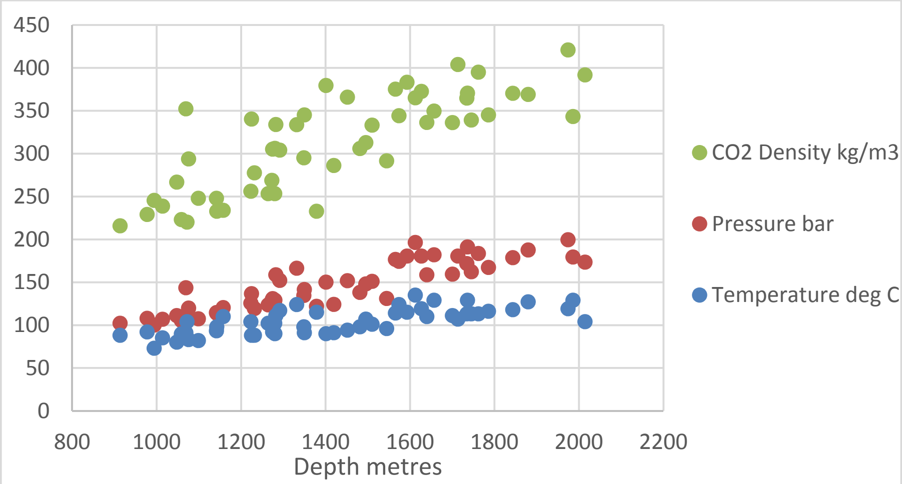
Annex 6 presents a discussion of monitoring requirements for CO_2 storage, which identifies various potential CO_2 leakage pathways that would need to be monitored. These include faults, boreholes and spill points. Extensive site-by-site characterization would be required to build confidence in each potential aquifer storage location. Then, comprehensive monitoring would be required to ensure that the long-term storage objectives are met.

Since about 1996, the Norwegian Sleipner project has achieved satisfactory storage of about one million tonnes per year of CO_2 stripped from natural gas in a deep saline aquifer below the sea floor. It is reported (MIT, 2014) that the CO_2 injection at Sleipner costs US$17 per tonne of CO_2 in order to avoid Norwegian carbon taxes of about US$60 per tonne of CO_2.

An important factor with regard to consideration of permanent storage of CO_2 in geological aquifers is the difference between the density and viscosity of CO_2 and water. At suitable geological formation depths for CO_2 storage (i.e., greater than 800 meters and up to 2,000 meters) the down-hole pressure might be between 100 bar and 200 bar. The underground temperature also increases with depth due to the geothermal gradient. Figure 6-4 shows the formation pressures and temperatures for the 52 formations in South Sumatra assessed by LEMIGAS.

Figure 6.4 shows the density of supercritical CO_2 at each of the down-hole sets of conditions surveyed. These density values range from 200 to 420 kg/m^3 compared with the density of water of 1000 kg/m^3. Hence, CO_2 will be very buoyant, relative to water, in porous formations. Furthermore, the viscosity of supercritical CO_2 at down-hole conditions is about ten times lower than the viscosity of water. Also, supercritical CO_2 would have no surface tension effects to inhibit flow through fine cracks in the cap-rock. Therefore, without the evidence of a seal provided by the presence of trapped hydrocarbons, the potential for leakage of CO_2 from saline aquifers would be high.

Figure 6-4 CO_2 temperature pressure and density vs depth



In view of these considerations, the prospect of identifying and characterizing sufficient deep saline aquifer storage locations in South Sumatra and West Java to accommodate reliably 14.7 million tonnes per year of CO_2 is not a sound basis for definition of capture-ready status.

6.4.2 Methodology of aquifer storage assessment

An assessment of the potential CO_2 storage capacity in deep aquifers can be made by multiplying together:

- The areal extent of suitable porous formations;
- The average thickness of suitable porous formations;
- The porosity of suitable porous formations;
- The density of CO_2 at the temperature and pressure conditions in the formation; and
- A storage efficiency factor.

The area, thickness and porosity of candidate formations can be estimated from seismic analysis. Such analysis is carried out intensively in hydrocarbon producing areas, where it may be supplemented by data from exploratory drilling for oil and gas. However, in other areas, without limited seismic surveying, the scale of suitable candidate porous formations can only be approximately inferred.

Where down-hole temperature and pressure conditions are not known, they can be inferred from known conditions at shallower depths via the local hydrostatic gradient and the local geothermal gradient, so that the density of supercritical CO_2 at any particular depth can be estimated reasonably well with empirical formulae, as used to compile Figure 6-4.

The storage efficiency factor for injected CO_2 has been extensively studied based on empirical evidence. Clastic rocks, such as sandstone, have different efficiency factors from deposited rocks such as limestone. Furthermore, there are significant discrepancies between the potential efficiency factor using different methodologies. Table 6-2 lists examples of efficiency factors reported by USDOE in 2010 and lower efficiency factors reported in IJGGC (Goodman, 2011). These factors are defined in terms of probabilities (P10, P50 and P90).[15]

The sets of formation data compiled by LEMIGAS for assessment of aquifer storage capacity comprise porous formations that are separate from, and additional to, the known hydrocarbon-bearing formations that comprise oil and gas fields. Therefore, the assessed aquifer storage capacity is additional to the storage capacity previously assessed in oil fields and gas fields.

Table 6-2 Efficiency factors for CO_2 storage in aquifers

	Low - P(10) (percent)	Median - P(50) (percent)	High - (P90) (percent)
USDOE - Clastic rock	7.4	14.0	24.0
USDOE - Limestone	10.0	15.0	21.0
IJGGC - Clastic rock	3.1	6.1	10.0
IJGGC - Limestone	3.5	5.2	7.3

Based on the relative proportions of clastic and limestone rocks and the USDOE methodology at P50, the efficiency factors used in the analysis in this report are 14.0 percent for South Sumatra, based on 52 data points, and 14.8 percent for West Java, based on 22 data points.

Finally, the aquifer storage capacities determined from available geotechnical data (largely from oil and gas basins) are extrapolated to cover the whole of the prospective areas of South Sumatra and West Java by multiplying by area factors of 5 and 3, respectively. The variance shown in Table 6-2 (3 percent to 24 percent) and the use of extrapolation indicates that there is large uncertainty in the estimated CO_2 storage capacity in aquifers.

The storage assessment methodology is based only the volume of porous rock. The methodology does not include any assessment of the impermeability of overlying formations, which would be required to act as cap-rock. In particular, porous rock formations that are not overlain by hydrocarbon-bearing formations, have no inherent indication of the absence of potential pathways for vertical migration of supercritical CO_2 to the surface.

6.4.3 Potential for aquifer storage of CO_2 in South Sumatra

An analysis of 52 sets of South Sumatra data, compiled by LEMIGAS for deep aquifers in hydrocarbon basins, identified 1776 square kilometers of candidate formations, at an average depth of 1350 meters, an average thickness of 47 meters, and with an average porosity of 20 percent. The average density of CO_2 under those conditions is 0.29 kg/liter. According to the USDOE methodology, with an average storage efficiency factor of 14.0 percent, the total CO_2 storage capacity in those 52 locations would be 696 million tonnes (or 683 million tonnes in 41 locations each with more than 2 million tonnes of capacity). Alternatively, according to the methodology detailed in the International Journal of Greenhouse Gas Control, with a median

[15] P10 denotes resources with 10 percent probability; P50 denotes resources with 50 percent probability; and P90 denotes resources with 90 percent probability.

storage efficiency factor of 5.7 percent, the total CO_2 storage capacity would be 285 million tonnes (or 279 million tonnes in 41 locations each with more than 1 million tonnes of capacity).

To estimate the total potential CO_2 storage in aquifers in South Sumatra, the assessed capacity is escalated by a factor of 5 to give estimates of 3,480 or 1,425 million tonnes of CO_2 storage according to the two assessment methodologies.

6.4.4 Potential for aquifer storage of CO_2 in West Java

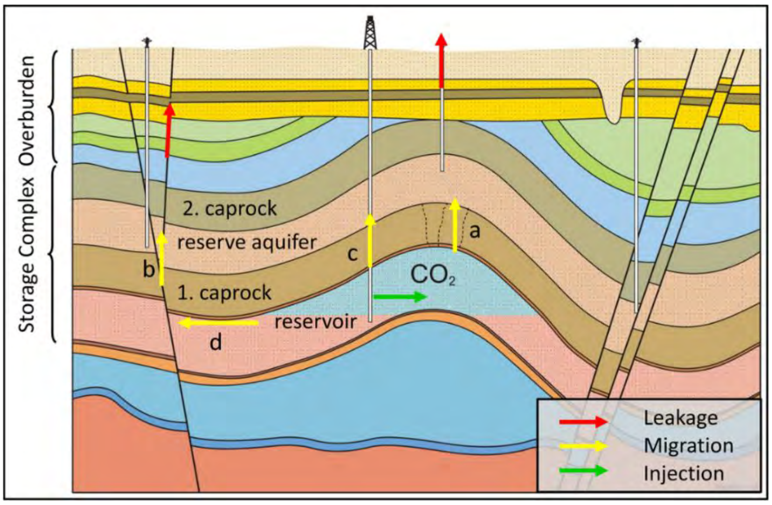
An analysis of 21 sets of West Java data, compiled by LEMIGAS for deep aquifers in hydrocarbon basins, identified 542 square kilometers of candidate formations, at an average depth of 1140 meters, an average thickness of 85 meters, and with an average porosity of 25 percent. The average density of CO_2 under those conditions is 0.26 kg/liter. According to the USDOE methodology, with an average storage efficiency factor of 14.3 percent, the total CO_2 storage capacity in those 21 locations would be 380 million tonnes (or 377 million tonnes in 18 locations each with capacity more than 2 million tonnes). Alternatively, according to the methodology detailed in IJGGC, with a median storage efficiency factor of 6.1 percent, the total CO_2 storage capacity in 21 locations would be 162 million tonnes (or 160 million tonnes in 18 locations each with capacity more than 1 million tonnes.)

To estimate the total potential CO_2 storage in aquifers in West Java, the assessed capacity is escalated by a factor of 3 to give estimates of 485 or 1,140 million tonnes of CO_2 storage according to the two assessment methodologies.

6.5 Monitoring of stored CO_2

Figure 6-5 (not to scale and modified from (Goerne, 2010)) illustrates potential leakage pathways for geologically stored CO_2. In the context of CCS, the primary purpose of monitoring is to ensure that leakage of CO_2 in minimal and that any minor leakage is quantified in order to certify the effectiveness of CO_2 storage. If actual and potential leakage of CO_2 is confirmed as minimal, then any concerns over health and safety issues at the surface may be dismissed. The wide range of monitoring methods that would be required are described in Annex 6.

Figure 6-5 Potential leakage pathways for CO_2 injected into saline formations



A case study on the cost of monitoring of CO_2 storage in a deep aquifer has been carried out for the Indonesian Gundih project. The costs are summarized in Table 6-3 and presented in more detail in Annex 6.

Table 6-3 Cost summary for Monitoring – Gundih case study

(10 years of injection and 100 years monitoring post closure)

Cost Item Groups	Cost (million US$)
Pre-Injection Monitoring	3.2
Surface Monitoring Cost	14.7
Project management, administration and engineering operating cost	4.4
4D Seismic Survey cost	26.5
Total Cost	**48.8**

Table 6.4 indicates that the total cost of short-term and long-term monitoring of a single CO_2 storage location could be in the region of US$50 million. The CO_2 storage assessments presented above indicate that a large number of storage locations would be required for each of the CO_2 storage options assessed. The average quantities of CO_2 that would be stored in locations with more than one million tonnes of CO_2 capacity are determined in Table 6-4.

Table 6-4 Estimation of average storage capacity per location

CO_2 storage type	Total potential storage capacity (millions of tonnes)	Number of CO_2 storage locations	Average storage capacity per location (millions of tonnes)
EOR in South Sumatra	63	20	3.1
Gas fields in South Sumatra	532	32	16.6
Gas fields in West Java	386	33	11.7
Aquifers in South Sumatra	279 - 683	41	6.8 – 16.6
Aquifers in West Java	160 - 377	18	8.9 – 20.9
Total	**1,420 – 2,041**	**144**	**9.9 – 14.2**

Table 6-4 indicates that the overall average storage location capacity is about 10 to 14 million tonnes of CO_2.

6.6 Other CCS storage studies in Indonesia

Two CO_2 storage capacity assessments are currently under way:

Feasibility Study of Gundih Gas Field (central Java). This study is funded by the Asian Development bank (ADB) as part of the joint effort between ADB and the Japan International Cooperation Agency (JICA) on the Pilot Study for Carbon Sequestration and Monitoring in Gundih Area. The site studied is located at Pertamina's Gundih gas field in central Java. This project aims to be the first in Southeast Asia to research and develop technology for CCS along with management and leakage monitoring. Institut Teknologi Bandung (ITB) was chosen as the research institute to carry out the assessment. ADB plans to bear the costs associated with sequestration in the pilot project if the survey finds an appropriate site and the Indonesian government makes a formal request.

CO2 Storage Screening Study on a Coal Gasification Project (South Sumatra). This study is currently in planning by Reliance Power Ltd for a Coal to Synthetic Natural Gas (SNG) project located within the coal mine area of ID-1 in South Sumatra. The SNG plant has a planned capacity of 4.2 MMscmd (146 MMscfd). Reliance has engaged an international engineering and manufacturing firm, Mitsubishi Heavy Industries (MHI), to carry out a Pre-Feasibility study to examine cost of CO_2 capture technology 'inside project boundaries'. JCoal and LEMIGAS are also involved in this project.

6.7 Costs of CO_2 storage

The capital costs of pipelines to deliver CO_2 from a power plant to gas field storage locations are assessed in Table 5-4. In West Java, the pipeline capital expenditures (capex) would be about US$3 per tonne of CO_2 delivered. In the case of South Sumatra, where the power plant is closer to the candidate gas fields, the pipeline capex would be about US$1 per tonne of CO_2 on average.

As determined in Section 6.5, the cost of monitoring is likely to be on average about US$3.5 per tonne of CO_2 stored.

The other cost center for CO_2 storage is well preparation. LEMIGAS advises that the capex from drilling a monitoring well to 2000 m depth might be about US$1 million and the cost of reworking an existing well as a monitoring well might be about US$0.7 million. Injection wells would need to be a large diameter than monitoring wells and would require some surface infrastructure. Other US references indicate well drilling costs in the region of US$3-4 million per well. Access to all the CO_2 storage capacity in a gas field may require a few wells to be drilled or reworked.

6.8 Long-term CO_2 storage capacity in South Sumatra

The primary objective of this study is to assess the technical and economic impacts of the application of CCS to two specific power plants over a specific time frame. However, the implementation of CCS will only occur within the context of long-term policy objectives to adopt CCS as a contributory strategy for meeting Indonesia's CO_2 emission reduction obligations. In that context, the long-term availability of storage capacity for CO_2 from all sources needs to be considered. The following analysis is carried out on the basis of the CO_2 production and storage capacity in South Sumatra.

The following assumptions are made:

- CCS at 90 percent capture is applied to the subject South Sumatra power plant (600MWe reduced to 415 MWe net output) from 2027 onwards, requiring 3.68 million tonnes per year of CO_2 storage;
- Capacity factor equals 80 percent with CCS, so that total power generated is 2.9 TWh per year. Thus, the CO_2 stored would be 1.265 tonnes per MWh;
- All new coal-fired power generation capacity after 2027 would have 90 percent CO_2 capture installed with the same performance parameter of 1.265 tonnes of CO_2 per MWh;
- The life of the subject South Sumatra power plant with CCS would be extended indefinitely.
- South Sumatra electricity production in 2024 is projected to be 14.198 TWh per year (RUPTL 2015 Table A8.3);
- Electricity production in South Sumatra grows at 8 percent per year to 2027, reducing to 5 percent per year by 2037 and to 3 percent by 2050 and 3 percent thereafter;
- 60 percent of electricity is generated from coal in 2027 increasing to 80 percent by 2037 and thereafter;
- CCS is only applied to new coal fired power generation;
- From 2020, 2 million tonnes per year of CO_2 from natural gas processing and other industrial sources would be used for EOR, and any surplus would be stored beyond 2027;
- From 2020, 4.5 million tonnes per year of CO_2 would be available from the proposed SNG plant to be used for EOR, and any surplus would be stored beyond 2027;
- No CO_2 from outside of South Sumatra (e.g., Natuna CO_2) would be stored in South Sumatra;
- CO_2 demand for EOR is 243 million tonnes (See Chapter 7);
- CO_2 storage capacity in depleted gas wells in South Sumatra is 537 million tonnes (See 6.3.2); and
- CO_2 storage capacity in saline aquifers in South Sumatra is 1,425 to 3,480 million tonnes (See 6.4.3).

On the basis of the foregoing assumptions, Figure 6-6 shows the impact of CCS on the installed power generation capacity and indicates the timeframes on which the assessed CO_2 storage capacities would become fully utilized.

The nominal generation capacity indicates the amount of power generation plant that would be installed on a no-CCS basis. The actual generation capacity indicates the amount of electricity that could be produced with CCS in place.

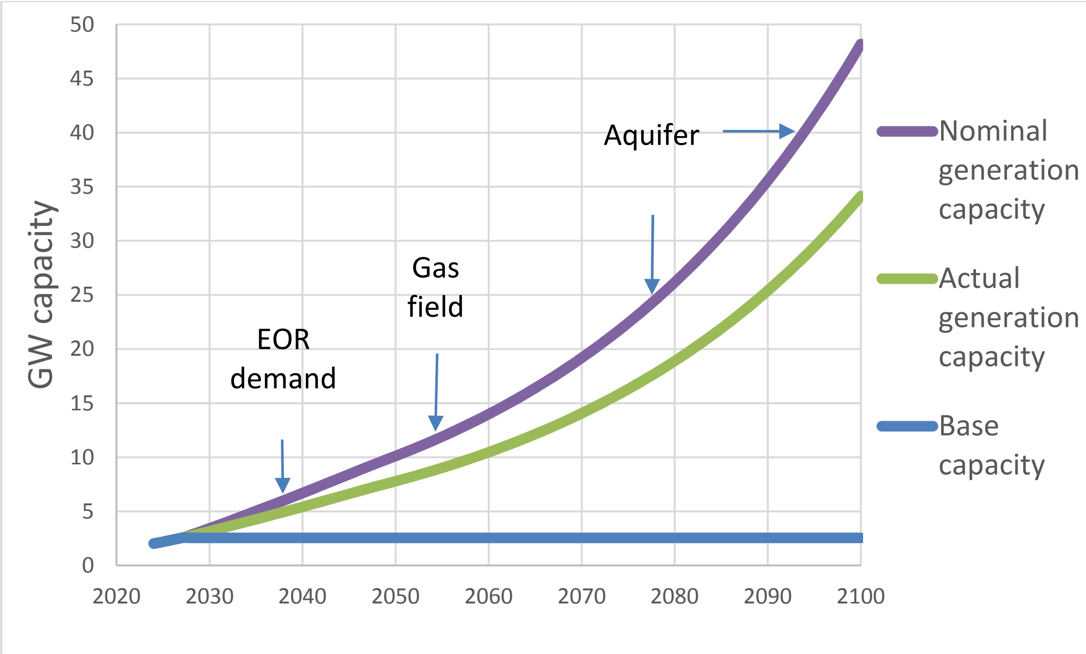


Figure 6-6 Long term CO_2 storage constraints

In view of the projected growth in coal fired generation, particularly in South Sumatra, if CCS is adopted as a means of meeting Indonesia's CO_2 emission reduction objectives then CCS would become constrained by the storage capacity of CO_2. The surplus CO_2 storage capacity in South Sumatra's gas fields would likely be all used by the middle of the century and the potential storage capacity identified in deep aquifers would likely be used up by the end of the century.

7. EOR MARKET REVIEW

The use of CO_2 for enhanced oil recovery presents a potential income stream for CO_2 captured from power plants as a cost-offsetting mechanism for CCS projects. It also provides a demonstration of CO_2 storage techniques. Furthermore, from the perspective of the CCS operator, EOR transfers CO_2 storage-related liabilities and costs to the oil field operators. Due to its long history of oil and gas exploration, and the abundance of oil and gas fields, South Sumatra has been identified as an attractive region for EOR.

This chapter comprises the following parts:

- an introduction on using CO_2 for EOR;
- an EOR market assessment with projections of supply and demand for CO_2 in South Sumatra; and
- a qualitative assessment of EOR as a cost-offsetting mechanism for CCS projects in Indonesia.

7.1 CO_2 for EOR

The injection of CO_2 into a depleted/depleting oil well is a well-established method of enhancing the recovery of oil, while also providing a secure geological trap for storing some CO_2 within reservoirs that previously held oil in place for millions of years. The use of CO_2 for EOR has been proven effective in many parts of the world, particularly in the USA. The use of CO_2 for EOR is by far the largest potential market for CO_2 as a commodity. EOR is not practiced in Indonesia at present, but it is expected that EOR technology will start to be exploited in South Sumatra from about 2020. The existing infrastructure and know-how in the oil and gas industry will also help facilitate demonstration of CO_2 transportation and storage methods.

In order to recover additional oil from a depleting oil reservoir, the pressure within the reservoir has to be raised to its initial level. That process is usually achieved through flooding the reservoir with water or pressurized CO_2. The latter is generally considered more effective, albeit more costly. There are two types of CO_2 flooding mechanisms:

- the miscible mechanism where CO_2 dissolves in the oil, thus reducing its viscosity, density, and residual concentration, while increasing its mobility; and
- the immiscible mechanism where pressurized CO_2 serves only to push oil from different parts of the reservoir towards the production wells.

7.2 Supply of CO_2 in South Sumatra

The supply of pure CO_2 in South Sumatra suitable for EOR could come from three principal sources: CO_2 stripped from natural gas, by-product CO_2 from a proposed SNG plant, and CO_2 captured from coal-fired power plant flue gas. There also may be other industrial sources of by-product CO_2. Emissions of CO_2 in other flue gases are less amenable to CO_2 capture than power plant flue gas, because the integration of the energy requirement into a power plant steam cycle is an essential feature of an efficient CO_2 capture scheme.

7.2.1 Emissions from low cost by-product CO_2 sources

In contrast to power plant flue gases that contain 10 -20 percent CO_2 and require costly and energy intensive separation, there are some sources of pure by-product CO_2 in South Sumatra, which would only require compression and transport to be ready to use in EOR applications. The main sources of by-product CO_2 are:

- CO_2 removed from high CO_2 natural gas resources to prepare it for delivery to customers. Such CO_2 sources arise at gas gathering stations where the CO_2 content of raw natural gas might need to be reduced from 10-30 percent CO_2 down to 4 percent CO_2 for delivery to customers; and
- CO_2 stripped from shifted synthesis gas in the proposed Synthetic Natural Gas plant that will make SNG from coal. The developers of this process have already identified the EOR market as a commercial outlet for the by-product CO_2 that the SNG process produces, which would reduce the embedded carbon content of the SNG product.

In total, by-product CO_2 sources in Sumatra are likely to amount to over six million tonnes of CO_2 per year. The availability of these low-cost, ready-to-use sources of CO_2 will impact on the EOR demand for high-cost CO_2 captured from coal-fired power plant flue gases.

7.2.2 Projection of CO_2 emissions from power plants in South Sumatra

Power sector CO_2 emissions are expected to continue growing in the coming decade as indicated in Chapter 2. The power sector has good data availability in the sector's master plan RUPTL. The current RUPTL (2015) indicates overall plans for new coal-fired power generation capacity in South Sumatra are about ten times greater than the capacity of the South Sumatra power plant considered in this study.

7.3 EOR market assessment in South Sumatra

7.3.1 Scope of the assessment

The study assessed a total of 127 oil fields in South Sumatra as potential sites to use CO_2 for EOR, as shown on Figure 7-1. Of all the oil fields investigated, only 52 have detailed information based on which reliable estimates of the reservoir capacity can be made, whereas the remaining fields only have information on depth, from which rough estimates of the reservoir capacity can be extrapolated.

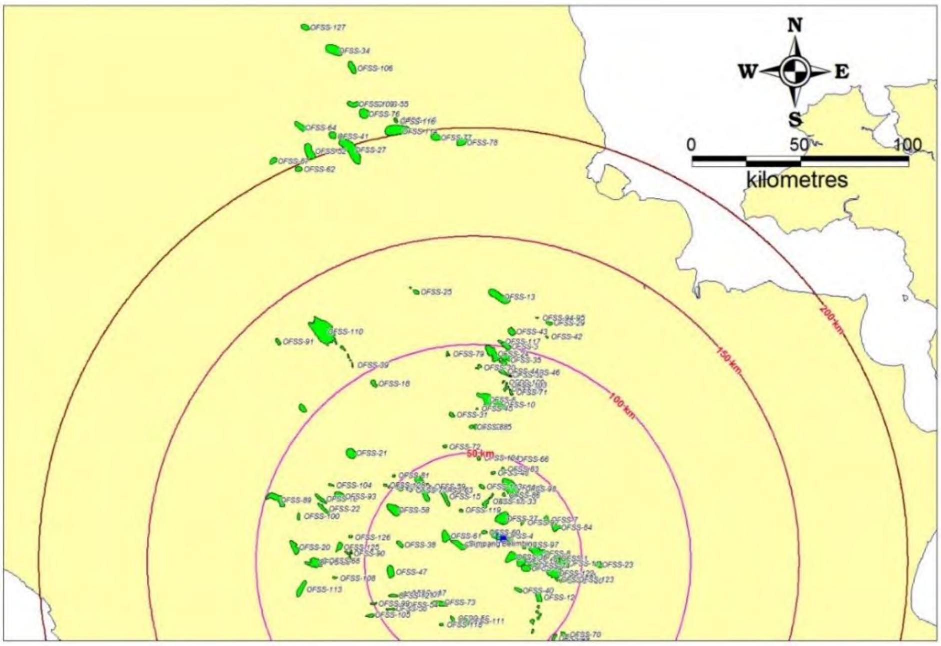
7.3.2 Methodology

EOR reservoir screenings were performed on the 52 oil fields on which detailed information was available using the screening criteria proposed by Taber et al. The criteria include a set of parameters -- such as API gravity[16], oil viscosity, current pressure, temperature, oil saturation,

[16] API Gravity is defined by the American Petroleum institute as = 141.5/RD – 131.5, where RD is the relative density compared to water.

remaining oil, formation depth, thickness, porosity, permeability, and rock type -- which help determine whether or not a reservoir is suitable for CO_2 injection for EOR. For the remaining 75 fields on which incomplete information was available, reservoir capacity was estimated using depth data assuming that oil fields deeper than 1 km were categorized as miscible while those shallower than 1 km were categorized as immiscible. Moreover, the reservoir pressures of the 75 fields where only depth was known were inferred from the pressure gradients of the 52 fields with more complete data.

Figure 7-1 Oil Field Locations in South Sumatra



7.3.3 Estimated EOR capacity

Based on the above methodologies, 96 of 127 oil fields, including the five largest reservoirs, were classified as miscible fields, and the remaining 31 immiscible. The 127 fields have a combined estimated capacity for around 243 million tonnes of CO_2 for EOR, as detailed in Chapter 6, which could recover approximately 661 million standard barrels of oil. An estimated 162 million tonnes of the demand for CO_2 will likely be absorbed by low-cost sources of CO_2 supplies, such as by-products from natural gas processing and the proposed SNG plant. The remaining demand of 81 million tonnes of CO_2 is only sufficient to absorb the CO_2 captured from the South Sumatra plant, but not enough for the West Java plant, as shown in Table 7-1.

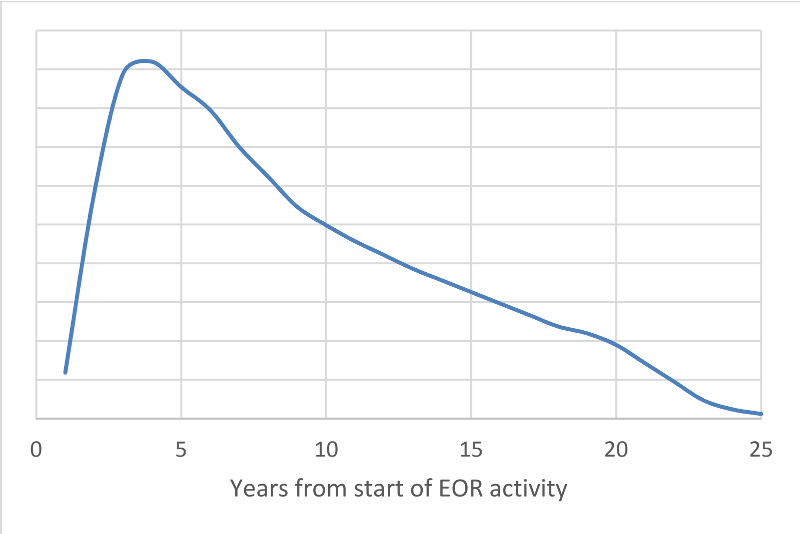
Table 7-1 Potential for EOR to accommodate CO_2 from CCS

	Million tonnes of CO_2
Demand for CO_2 for EOR in South Sumatra	243
Supply from low cost CO_2 sources over 25 years	162
Remaining demand	81
South Sumatra plant at 90 percent capture for 20 years	74
Remaining demand	7
West Java plant at 90 percent for 20 years	218

7.3.4 EOR demand profile

Figure 7-2 shows the typical profile for CO_2 demand for an oil well over 25 years of CO_2 enhanced oil production. This profile shows a high demand in the early years for flooding, peaking in Year 4, followed by a declining CO_2 demand in later years. This CO_2 demand profile is based on overseas EOR experience, mostly in the USA, adapted by LEMIGAS for the mix of miscible and immiscible EOR opportunities in South Sumatra.

Figure 7-2 CO_2 demand profile for EOR



7.3.5 Supply and demand considerations

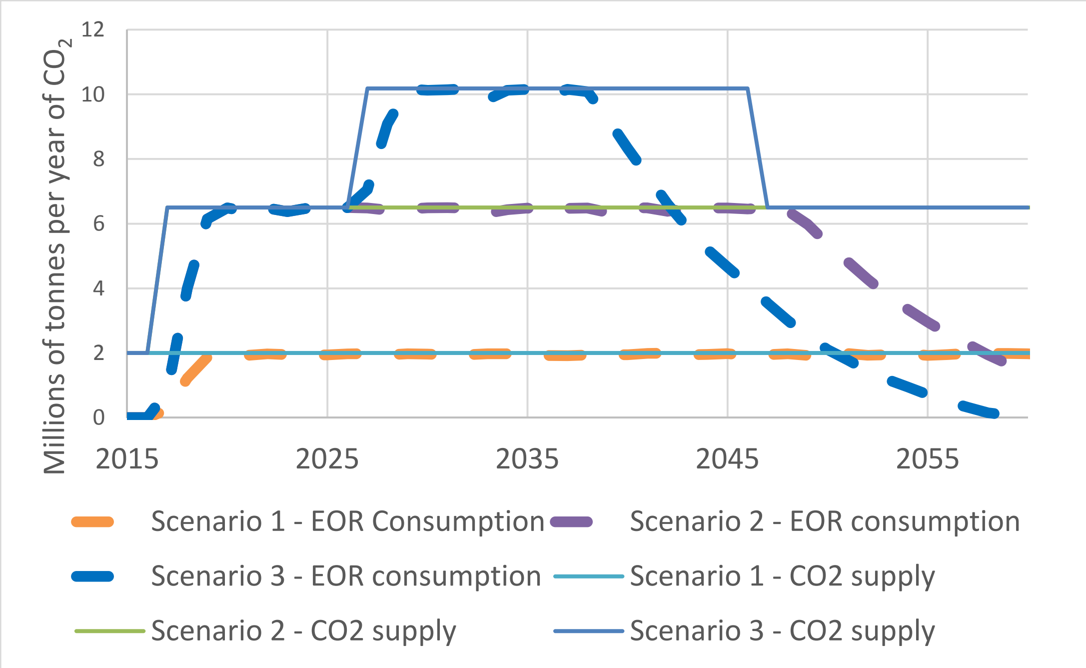
The implementation of a CO_2-EOR operation on a depleted oil field will depend on the availability of an adequate supply of CO_2. The foregoing assessment and profile indicates that on average about 2 million tonnes of CO_2 would be required over 25 years for an EOR campaign on each oil field. Before commencing an EOR campaign, an oil field operator would need to be confident that adequate CO_2 would be available over the life of the EOR campaign. Therefore, the uptake of EOR would be constrained by the availability of CO_2 and EOR would probably not be commenced on an oil field until a dedicated supply of CO_2 was known to be available.

Three CO_2 supply scenarios are considered:

- Scenario 1 – only by-product CO_2 is available from existing natural gas processing plants combined with other industrial sources, which is assumed to be 2 million tonnes per year available indefinitely for EOR;
- Scenario 2 – in addition, by-product CO_2 from the proposed Synthetic Natural Gas Plant would be available for EOR at a rate of 4.5 million tonnes per year indefinitely; and
- Scenario 3 – in addition, CO_2 captured from the South Sumatra Power Plant under consideration would be available for EOR at a rate of 3.7 million tonnes per year from 2027 to 2047.

Figure 7-3 shows projected supply and demand balances for each of the above scenarios based on CO_2 demand profile shown in Figure 7-2.

Figure 7-3 EOR supply and demand scenarios



EOR Supply Scenario 1 assumes that the availability of pure pipelined commodity CO_2 is limited to that available from gas processing plants, with maybe other relatively small sources from industrial plants; and that those sources combined could deliver 2 million tonnes of commodity CO_2 per year indefinitely. On that basis, it would take over 120 years to supply sufficient CO_2 to exploit all the EOR potential identified.

EOR Supply Scenario 2 assumes that the proposed coal to SNG plant is built in 2017 and can supply 4.5 million tonnes per year of commodity CO_2 to the EOR market. Figure 7-3 shows that would enable a large number of oil field EOR operations to be commenced earlier. Under Scenario 2 there would be sufficient CO_2 available for EOR to have been commenced on all 127 candidate oil fields by about 2045. The demand profile shown in Figure 7-2 means that there would be EOR operations continuing in South Sumatra through to beyond 2060.

EOR supply Scenario 3 assumes that there is also commodity CO_2 available at 3.7 million tonnes per year captured from the South Sumatra power plant from 2027 to 2047 as well as the SNG CO_2 and CO_2 from other sources. Figure 7-3 shows that this larger supply of CO_2 would enable more EOR to be exploited earlier and that all EOR opportunities could be in operation by about 2035. Under this scenario, all EOR activity would be completed by 2060 and the amount of SNG CO_2 used for EOR would be reduced by the amount supplied by CO_2 captured from the power plant, which would be about two thirds of all the power plant CO_2 produced between 2027 and 2047.

Although the availability of CO_2 for EOR is constrained by supply under Scenario 3 from 2029 to 2038, the scope for accommodating more CO_2 from other sources would be limited to about 2 million tonnes per year for a few years. That opportunity is insufficient to justify pipelining captured CO_2 from West Java to South Sumatra.

Figure 7-3 shows that there is potential for more than half of the CO_2 captured from the South Sumatra power plant to be sold for EOR within the region, and thereby bring forward EOR operations and reduce the cost of CO_2 capture. However, that would displace later use of other by-product CO_2 and therefore, over time, would not affect the overall storage of CO_2.

Figure 7.3 also shows that well before the end of the planned 25-year life of the South Sumatra power plant there would be no more demand for CO_2 from that source for EOR. So EOR does not provide on-going storage for CO_2 captured from power plants in South Sumatra.

7.4 Economic considerations concerning EOR for CO_2 Storage in Indonesia

Several key findings have emerged from the EOR market assessment and the plant level studies in this chapter. Although the demand for CO_2 in EOR is sizable in South Sumatra, it is insufficient to absorb all the CO_2 captured from both reference power plants in the high capture percentage scenarios even if there were no competing source of CO_2 supply.

Given the supplies of CO_2 for EOR from other sources are likely motivated by similar policy drivers, the various CO_2 supplies are likely to compete for EOR market share. Thus, CO_2 captured from thermal power plants will likely be competing with CO_2 available from other sources for the limited EOR opportunities available. From the perspective of the cost of CO_2 capture and supply, at approximately US$70-80 per tonne of CO_2 from coal-fired power plants, the power sector would be at a commercial disadvantage compared with sources such as natural gas processing, which only involves compression and transport at an estimated US$28 per ton of CO_2 (ADB, 2013).

Moreover, the upside offered by EOR to CCS projects is subjected to further uncertainties with respect to the following factors:

The willingness-to-pay for CO_2 for EOR

Oil field operators will only be willing to purchase CO_2 when the prevailing oil market price can justify the incremental cost of CO_2 for the EOR operation. Thus, the volatility of the oil price will be one of the key risk factors on the upside that EOR may provide. If 243 million tonnes of CO_2 can release 661 million tonnes of additional oil via EOR in South Sumatra, then a purchase price of say US$40 per tonne of CO_2 (as has reportedly been paid in some deals in the USA), would add about US$15 to the production cost of a barrel of oil.

The cost of delivery of CO_2 to the EOR sites

Pipeline cost is a function of the distance between the CO_2 source and the EOR sites, and the quantity of the CO_2 transported through the pipeline. A long-distance CO_2 delivery route from West Java for part of the CO_2 would render opportunities of EOR unattractive due to the remaining need for alternative delivery routes for CO_2 from that source to other CO_2 storage sites. Moreover, in a competitive market, with uncertainties of demand, the actual quantity of CO_2 transmitted through a pipeline for EOR may experience considerable fluctuation, running the risk of the pipeline becoming a stranded asset.

Continuity of supply for EOR

The nature of power plant operation is that it follows electricity demand. Even the base load plants proposed would only have 80 percent capacity factor, with significant down time for planned maintenance and unplanned outages. The very large volumes of high-pressure CO_2 involved would make CO_2 storage for significant periods impractical. It is noted in Chapter 5 that pipeline storage of CO_2 would be no more than an hour or so. EOR operators may be reluctant to enter into contracts for CO_2 supplies on an interruptible basis.

Given all the above considerations, the South Sumatra power plant is well placed to take advantage of EOR opportunities is South Sumatra, whereas the West Java power plant is not. Moreover, EOR should only be viewed as a supplemental cost-offsetting mechanism in South Sumatra, instead of the primary means of CO_2 storage for either of the two reference power plants specifically, or for the power sector in general.

8. THE ECONOMICS OF CCS

This chapter assesses the incremental costs and benefits of CCS.

On the cost front, the assessments comprise:

- the levelized cost of electricity from the two reference power plants in West Java and South Sumatra without CCS;
- the incremental cost of CCS on the LCOE under different scenarios;
- a comparison of the reference coal-fired power plants with CCS to alternative technologies on a LCOE basis; and
- an economic assessment of EOR as a cost-offsetting mechanism for CCS.

On the benefit front, the assessments include:

- the global environmental benefit of reduced emissions of CO_2; and
- the local environmental and health benefits of reduced emissions of local pollutants in the form of NOx, SO_2 and particulates.

8.1 Assumptions

The economic analysis was carried out over a project lifetime of 30 years, inclusive of a 5-year construction period, at a discount rate of 10 percent per year.

8.1.1 Baseline parameters of the two reference plants

Table 8-1 provides a summary of the key parameters of the reference coal-fired power plants in West Java and South Sumatra.

Table 8-1 Baseline Parameters of Reference Plants

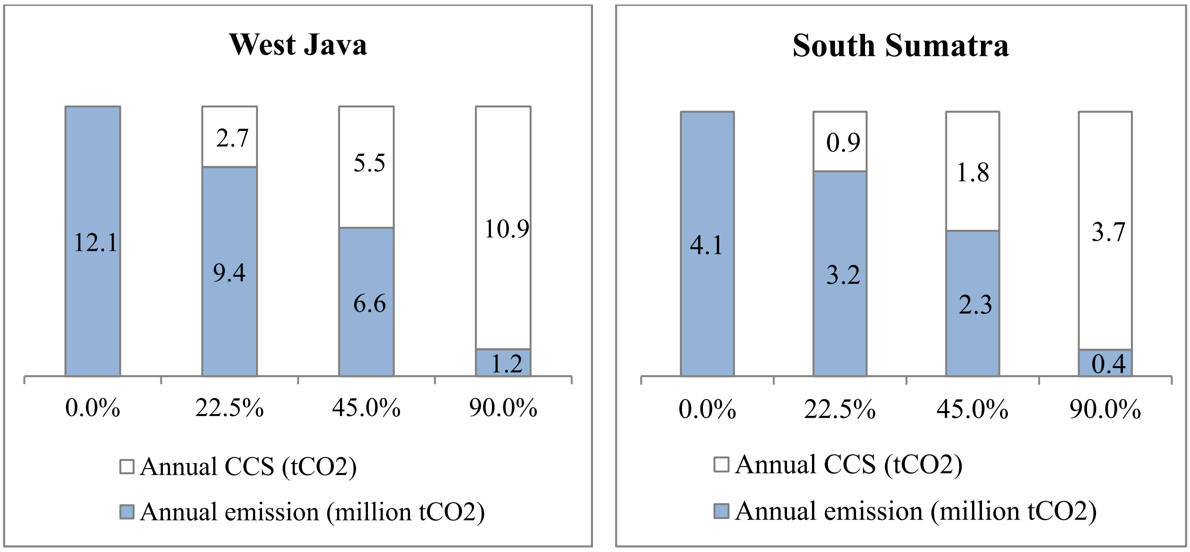
	West Java	**South Sumatra**
Installed Capacity (net to the grid)	2 x 1,000 MW	1 x 600 MW
Technology	Ultra Supercritical	Supercritical
Commissioning year	2020	2022
Source of coal	Kalimantan	Mine mouth
Desulfurization technology	Seawater scrubber	None
Capacity Factor	80%	80%
Auxiliary consumption ratio	8%	8%
Plant Efficiency (hhv)	38.5%	34.6%
Coal Calorific Value (HHV) Price	Typical 3,880 kcal/kg (hhv) US$50.0 per ton[1]	2,600 kcal/kg (hhv) US$20.0 per ton
Investment costs(US$ million)[2]	3,753	1,235
Annual O&M (US$ million)	92.1	16.6

Notes: 1. Ton = US ton. 2. * Capex of power plants in West Java and South Sumatra are in 2020 and 2022 dollars, respectively, including the investment cost of the transmission line that delivers power to the grid.

8.1.2 Capture Scenarios

In order to provide a systematic and comprehensive approach for considering CCS retrofit to the power plants, three cases of commercial-scale CCS were investigated: 22.5 percent, 45 percent and 90 percent of CO_2 capture, respectively. The corresponding CO_2 emissions used for the economic analysis are shown in Figure 8-1, and are based on nominal gross power outputs with 8 percent own-use as distinct from the nominal net power output basis used in the technical analysis. These cases are developed to show the dependence of energy penalty, utility requirements, and capital cost increment on the extent of CO_2 capture recovery.

Figure 8-1 CO_2 emissions from the reference plants under each scenario



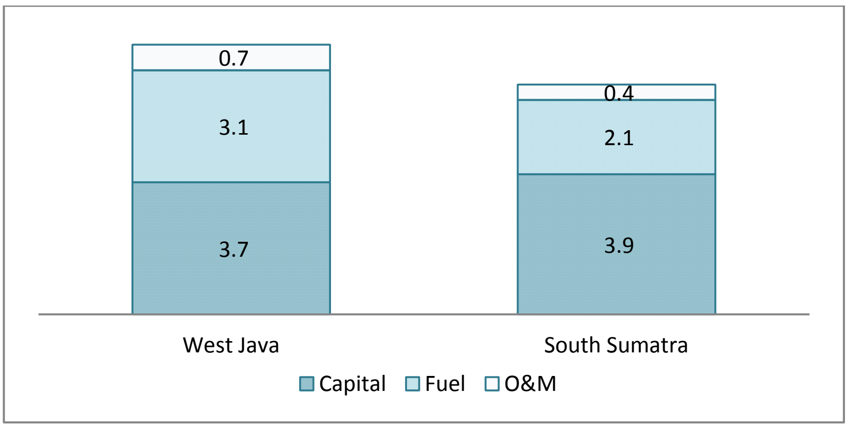
8.1.3 CCS implementation timing scenarios

Four implementation schedules were investigated, one with no delay, and three with 5 years, 10 years and 15 years delay, respectively, from the commissioning year of the power plant.

8.2 LCOE of the reference plants without CCS

Based on the above assumptions, the LCOE was estimated at 7.5 cent/kWh and 6.4 cent/kWh for the West Java and South Sumatra power plants, respectively. The lower LCOE from the South Sumatra plant was primarily driven by the lower cost of coal at the mine mouth.

Figure 8-2 LCOE of the reference plants without CCS (US cents/kWh)



8.3 The incremental cost of CO_2 capture

8.3.1 Cost of CO_2 Capture Investments

CO_2 capture requires additional investments in the following equipment:

a. high efficiency Flue Gas Desulphurization units;
b. high efficiency Selective Catalytic Reduction units;
c. MEA CO_2 capture process;
d. CO_2 compression and dehydration plant, and
e. Pass out steam power recovery turbine.

Some of the above-mentioned equipment is installed in multiple units, as detailed in Table 4.6, to accommodate the very large volumes of gas involved.

Of all the required CO_2 capture equipment, the most expensive item is the MEA scrubber, which is the main process for separating CO_2 from the power plant flue gas. Under the 90 percent capture scenario, the MEA scrubber accounts for more than half of the incremental investments. Table 8-2 provides a summary of the corresponding investment level in each capture scenario.

Table 8-2 Additional CAPEX and OPEX for CO_2 capture

(US$ million)	**West Java 2x 1000 MW**			**South Sumatra 1x600 MW**		
Capture fraction scenario	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
Compression and dehydration	173	123	61	94	58	43
MEA scrubber	870	460	291	425	248	159
FGD	378	214	119	128	98	79
SCR	180	180	180	56	56	56
Pass out turbine	80	40	30	40	30	30
Total CAPEX[1] for CO_2 capture	1681	1017	681	743	490	357
Annual OPEX[2] for CO_2 capture	182	148	115	65	53	40

Notes: [1] CAPEX denotes capital expenditures; [2] OPEX denotes operating expenditures.

8.3.2 Energy Penalty

CO_2 capture is an energy-consuming process. Energy for the thermal swing process, with which MEA captures CO_2, reduces electricity production and the subsequent process of CO_2 dehydration and compression consumes electricity. The additional energy consumed for capturing CO_2 is a "penalty" to the net output of the power plant. The higher the capture percentage, the more energy it will consume, thus the higher the energy penalty. Table 8-3 provides a summary of the energy penalties for the two reference power plants.

Table 8-3 CO_2 capture associated energy penalty under each capture scenario

	West Java				South Sumatra			
	None	**90%**	**45%**	**22.5%**	**None**	**90%**	**45%**	**22.5%**
Electricity output (MWe)	2000	1449	1725	1862	600	415	508	564
Energy penalty (%)	-	28%	14%	7%	-	31%	15%	6%

8.3.3 O&M costs

Besides the energy penalty, CO_2 capture will also incur additional operation and maintenance (O&M) costs. Table 8-2 provides a summary of the estimated incremental annual O&M cost associated with each CO_2 capture scenario.

8.3.4 Impact of CO_2 capture on LCOE

Under the no implementation delay scenario, CO_2 capture alone results in an estimated additional cost of 2.1-6.8 US cents per kWh in West Java, and 2.6 – 8.4 US cents per kWh in South Sumatra, on the LCOE, depending on capture fraction. Under the 90 percent capture scenario, the energy penalty comprises more than half the CO_2 capture-related incremental cost. Table 8-4 provides a summary of the breakdown of incremental LCOE resulting from different CO_2 capture fractions at the power plant.

Table 8-4 The incremental cost of CO_2 capture on LCOE (No delay scenario)

	West Java			South Sumatra		
(US cents/kWh)	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
Capital	1.4	0.9	0.6	2.1	1.4	1.0
Energy penalty	3.9	1.5	0.7	4.6	1.7	0.5
O&M	1.4	1.1	0.9	1.7	1.4	1.0
Total	**6.8**	**3.5**	**2.1**	**8.4**	**4.4**	**2.6**

8.4 CO_2 Transportation and Storage

8.4.1 CO_2 transportation

Incremental cost of CO_2 transportation

CO_2 is captured and compressed at the power plant. A pipeline will be constructed to transport the captured CO_2 to a distribution hub from which CO_2 distribution pipelines will be constructed to the storage and/or EOR locations. The incremental investment required for CO_2 transmission and distribution is a function of the length of the pipeline and its diameter, the latter of which is determined by the maximum quantity of CO_2 to be transmitted through the pipeline at any given time. The investment cost is assumed at US$50,000 per kilometre per inch in diameter for on-shore pipelines, and at US$75,000 per km-inch for off-shore pipelines. The annual O&M for CO_2 transportation is assumed at 8 percent of the total investment costs of CO_2 transportation pipelines.

The West Java power plant is considerably farther from the identified CO_2 storage locations in West Java than the South Sumatra power plant is from nearby CO_2 storage locations in South Sumatra. Moreover, at the same capture percentage, the West Java plant has approximately three times more CO_2 to be transported than the South Sumatra plant. As a result, the incremental cost associated with CO_2 transmission is considerably higher for West Java than for South Sumatra. Table 8-5 provides a summary of the incremental investments for CO_2 transportation under each scenario.

Table 8-5 Additional discounted investments for CO_2 transportation

	West Java (US$ mln, 2020 dollar)			South Sumatra (US$ mln, 2022 dollar)		
	90%	**45%**	**22.5%**	**90%**	**45%**	**22.5**
No delay with 25 years of operation	422	309	210	59	36	24
5 year delay with 20 years of operation	383	281	191	54	33	23
10-year delay with 15 years of operation	269	119	91	26	15	1
15-year delay with 10 years of operation	105	77	53	3	1	1

Impact of CO_2 transportation on LCOE

Under the no-delay scenario, on an LCOE basis, the incremental cost of CO_2 transportation is relatively small -- at most 0.9 US cents per kWh and 0.4 US cents per kWh for West Java and South Sumatra, respectively -- compared with an incremental cost of 6.8 US cents per kWh and 8.4 US cents per kWh from CO_2 capture for each case, respectively. Table 8-6 provides a summary of the incremental cost of CO_2 transportation.

Table 8-6 Incremental cost of CO_2 transportation on LCOE

	West Java			**South Sumatra**		
(US cents/kWh)	90%	45%	22.5%	90%	45%	22.5%
No delay with 25 years of operation*	0.86	0.53	0.33	0.42	0.21	0.13
5 year delay with 20 years of operation	0.66	0.44	0.29	0.04	0.02	0.00
10-year delay with 15 years of operation	0.41	0.17	0.13	0.02	0.01	0.00
15-year delay with 10 years of operation	0.14	0.10	0.07	0.01	0.01	0.00

8.4.2 CO_2 storage

Incremental cost of CO_2 storage

In places where existing infrastructure, such as depleted oil and gas fields, are available and can be used for storing CO_2, the incremental costs associated with CO_2 storage is relatively small. To be conservative, this study assumes an incremental investment of US$3 million per work-over of each depleted well, plus US$1 million per well in potential liabilities, and an additional 8 percent in annual O&M. The corresponding investments are shown in Table 8-7.

Table 8-7 Additional investments for CO_2 storage

(US$ million)	West Java (US$ mln, 2020 dollar)			South Sumatra (US$ mln, 2022 dollar)		
	90%	**45%**	**22.5%**	**90%**	**45%**	**22.5**
No delay with 25 years of operation	110	90	22	37	18	11
5 year delay with 20 years of operation	100	81	20	34	16	10
10-year delay with 15 years of operation	67	23	12	19	12	6
15-year delay with 10 years of operation	32	15	8	12	6	4

Impact of CO_2 storage on LCOE

Under the no delay scenario, the incremental cost of CO_2 storage is as low as 0.2 and 0.3 US cents per kWh for West Java and South Sumatra, respectively, accounting for less than 4 percent of the total incremental cost of CCS. Table 8-8 provides a summary of the incremental cost of CO_2 storage under different scenarios.

Table 8-8 Incremental cost of CO_2 storage on LCOE

	West Java			South Sumatra		
(US cents/kWh)	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
No delay with 25 years of operation	0.22	0.15	0.04	0.26	0.10	0.06
5 year delay with 20 years of operation	0.17	0.13	0.03	0.13	0.06	0.03
10-year delay with 15 years of operation	0.10	0.03	0.02	0.07	0.03	0.02
15-year delay with 10 years of operation	0.04	0.02	0.01	0.04	0.02	0.01

8.5 The incremental cost of CCS

8.5.1 LCOE of coal-fired generation with CCS

Under the 90 percent capture with no implementation delay scenario, the CCS process will more than double the cost of supply from both reference plants, raising the LCOE from 7.5 US cents/kWh to 16.1 US cents/kWh in West Java, and from 6.4 US cents/kWh to 15.2 US cents/kWh in South Sumatra. The energy penalty is the key contributor to the incremental cost of CCS, accounting for nearly half of the total incremental cost under the 90 percent scenario.

Table 8-9 and Table 8-10 provide a summary of the incremental cost breakdown under each scenario.

Both implementation timing of CCS and capture percentage play important roles with respect to the incremental cost of CCS. Postponing the implementation of CCS by 5 years could help bring the LCOE down to a more affordable level by cutting the incremental cost of CCS by half (from 8.6 to 4.3 US cents per kWh in West Java, and from 8.8 to 4.4 US cents per kWh in South Sumatra). Moreover, postponing CCS implementation would also allow the reference plants to learn from the CCS pilot projects in other places.

Table 8-9 West Java Breakdown of LCOE

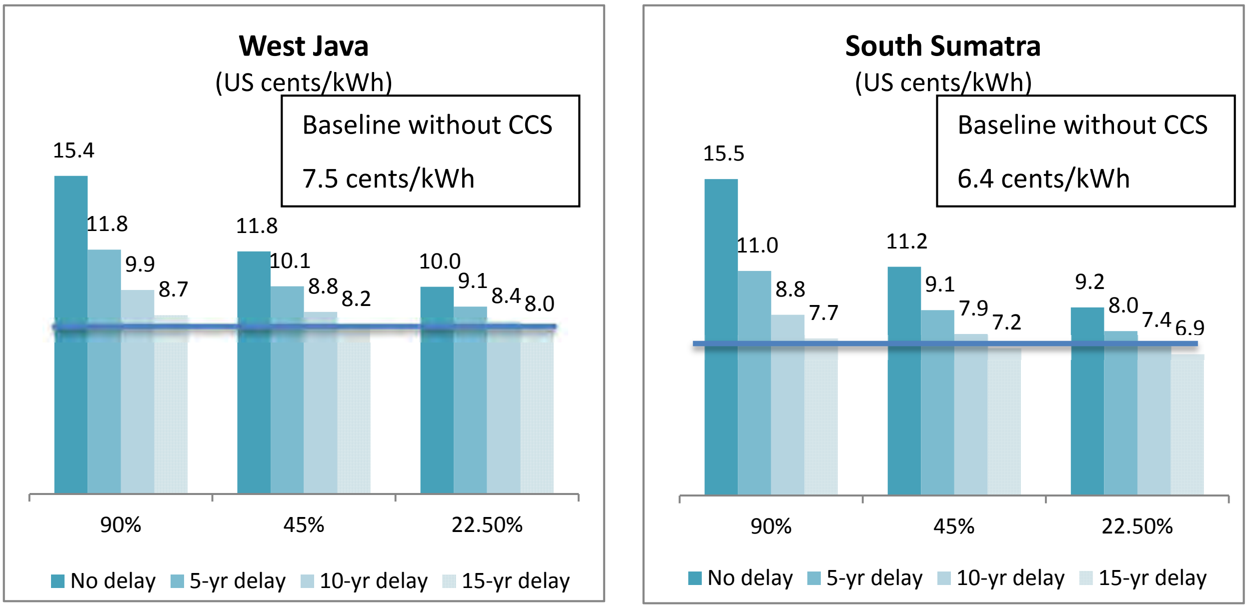
(US cents per kWh)	No delay			5-year delay			10-year delay			15-year delay		
	90%	**45%**	**22.5%**	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
Baseline	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Capture	6.8	3.5	2.1	3.5	2.0	1.2	1.8	1.1	0.7	1.0	0.6	0.4
Transportation	1.4	0.9	0.5	0.7	0.4	0.3	0.4	0.2	0.1	0.1	0.1	0.1
Storage	0.4	0.2	0.1	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Total	**16.1**	**12.2**	**10.3**	**11.8**	**10.1**	**9.1**	**9.9**	**8.8**	**8.4**	**8.7**	**8.2**	**8.0**

Table 8-10 South Sumatra Breakdown of LCOE

(US cents per kWh)	No delay			5-year delay			10-year delay			15-year delay		
	90%	**45%**	**22.5%**	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
Baseline	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Capture	8.4	4.4	2.6	4.2	2.5	1.5	2.2	1.4	0.9	1.2	0.7	0.5
Transportation	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage	0.3	0.2	0.1	0.2	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0
Total	**15.2**	**11.1**	**9.1**	**10.8**	**9.0**	**8.0**	**8.8**	**7.9**	**7.3**	**7.6**	**7.2**	**6.9**

Similarly, reducing the CO_2 capture percentage from 90 percent to 45 percent under the no implementation delay scenario could reduce the total incremental of cost of CCS from 8.6 to 4.7 US cents per kWh in West Java, and from 8.8 to 4.7 US cents per kWh in South Sumatra. However, both the implementation delay and the lower level of capture come at the expense of higher CO_2 emissions.

Figure 8-3 LCOE of coal-fired generation with CCS (US cents/kWh)



The "No delay" case (i.e., installing CCS in Indonesia in the same year of the plant's initial operation -- the year 2020 for the West Java plant and 2022 for the Sumatra plant) is very unlikely due to fact that CCS regulations and institutional arrangements will take a long time to be implemented.

8.5.2 LCOE comparison with other generation technologies

In this section, comparisons are carried out between coal-fired generation plus CCS with other types of power generation in terms of their level of emissions and LCOE. Table 8-11 provides a summary of PLN's average cost of supply according to generation type in 2013.

In 2013, PLN's weighted average cost of supply was at around 11.04 US cents per kWh. Of all the generation technologies, hydro and steam (coal) presented the lowest cost of supply. The average cost of coal-fired generation in the year was at 6.58 US cents per kWh compared with the estimated 7.5 and 6.4 US cents per kWh from the West Java and South Sumatra plants, respectively. Besides coal and hydro, the next tier of technologies in terms of cost of supply was geothermal at 10.10 US cents per kWh and CCGT at 11.61 US cents per kWh. The third tier of generation technology in terms of cost of supply was gas turbine, diesel and solar at 27.03, 30.07 and 32.70 US cents per kWh, respectively.

Table 8-11 PLN's average cost of supply from generation technologies

(US cents/kWh)	Fuel	Maintenance	Depreciation	Others	Personnel	Total
Hydro	0.23	0.37	0.77	0.03	0.13	**1.52**
Coal/Steam	5.08	0.45	0.99	0.02	0.04	**6.58**
Geothermal	7.81	0.99	1.15	0.02	0.13	**10.10**
CCGT	9.35	0.50	0.68	0.03	0.04	**10.61**
Gas turbine	24.09	1.14	1.66	0.02	0.12	**27.03**
Diesel	21.73	5.42	1.73	0.18	1.01	**30.07**
Solar		3.55	29.05	0.02	0.08	**32.70**
Average	**9.37**	**0.63**	**0.95**	**0.03**	**0.08**	**11.04**

Note: exchange rate at IDR 10,930 = US$1.00. *Source*: Table 38, PLN Statistics 2013.

Coal-fired generation with CCS is competitive, in terms of LCOE at a comparable level of emissions, with geothermal and CCGT.

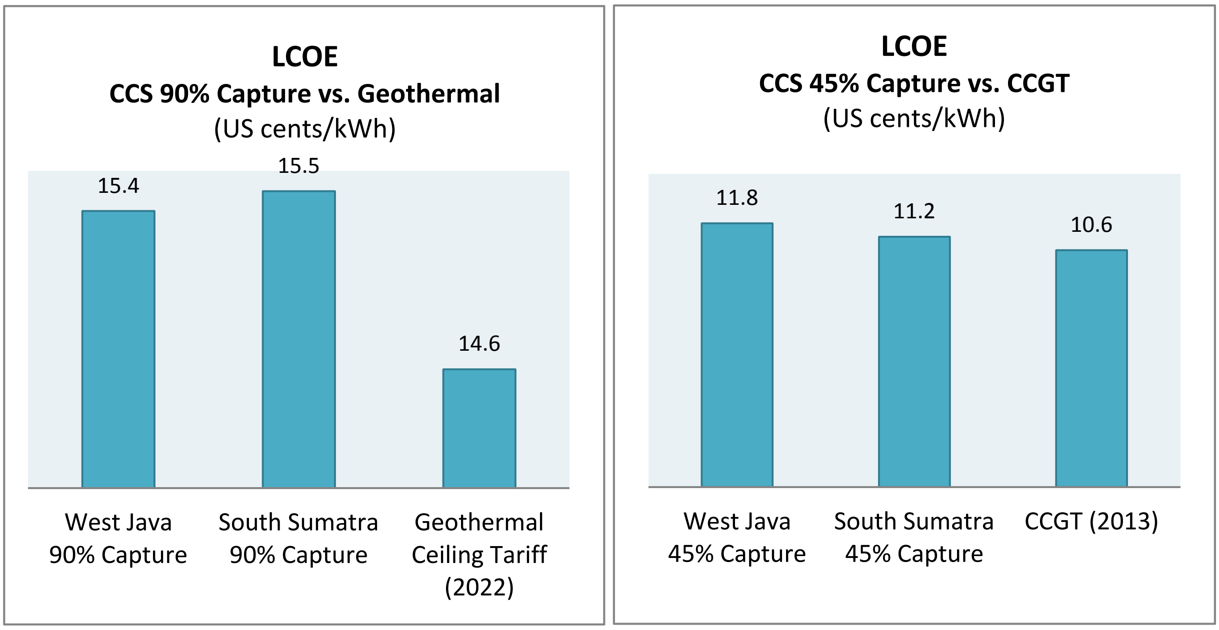
In terms of CO_2 emissions and availability of power generation, coal-fired generation with 90 percent capture is comparable to geothermal-based generation. According to MEMR's Regulation 17/2014, the ceiling price for geothermal in Java and Sumatra is set at 14.6 US cents per kWh for geothermal plants commissioned in the year 2022, which is comparable to the LCOE of the West Java and South Sumatra power plants with 90 percent capture without delay in implementation of CCS. Geothermal ceiling tariffs are listed in Table 8-12.

Table 8-12 Ceiling price for Geothermal in Indonesia

Commercial Operation Date	Ceiling Tariff (US cents per kWh)		
	Region I	Region II	Region III
2014	11.8	17.0	25.4
2016	12.2	17.6	25.8
2017	12.6	18.2	26.2
2018	13.0	18.8	26.6
2019	13.4	19.4	27.0
2020	13.8	20.0	27.4
2021	14.2	20.6	27.8
2022	14.6	21.3	28.3
2023	15.0	21.9	28.7
2024	15.5	22.6	29.2
2025	15.9	23.3	29.6

Source: Regulation 17 Tahun, 2014. MEMR.
Notes: Region 1 covers Sumatra, Java, Bali; Region 2 covers Sulawesi, Nusa Tenggara, Maluku, Irian and Kalimantan; and Region 3 covers isolated areas in Region 1 and Region 2 whose electricity supply is dominated by oil based generation.

Figure 8-4 LCOE Comparisons of CCS with Geothermal and CCGT



In terms of CO_2 emissions, coal-fired generation with 45 percent capture is comparable to CCGT operating at base load (See discussion in Section 3.3.3). In terms of LCOE, coal-fired generation with CCS at 45percent capture is comparable to the LCOE of CCGT in 2013, while reducing the volatility of the cost of electricity supply due to fluctuation in the price of natural gas used in CCGT.

8.6 Cost of CO_2 abatement and offsetting mechanisms of EOR

Before estimating the cost of CO_2 abatement associated with CCS, a distinction needs to be drawn between two CO_2 abatement measures, one focusing on the amount of CO_2 actually captured in the CCS process, and the other on the net amount of CO_2 emission avoided on a power output parity basis. On a power output parity basis, the production of pure CO_2 is higher because of the energy penalty of CCS. The amount of CO_2 captured is thus greater than the amount of CO_2 emission avoided. Figure 8-5 provides an illustration of the difference between the two CO_2 abatement measures.

The choice of the measure will depend on the application. For example, when commodity CO_2 is the focus of the analysis, such as in CO_2 utilization schemes like EOR, the captured-basis is a more appropriate measure by accounting for the actual amount of CO_2 captured with the CCS process. Yet, when comparing the costs of CO_2 abatement across different technologies, the avoided-basis is more appropriate because it is presented on an electricity output parity basis.

Figure 8-5 The difference between CO_2 captured and CO_2 avoided

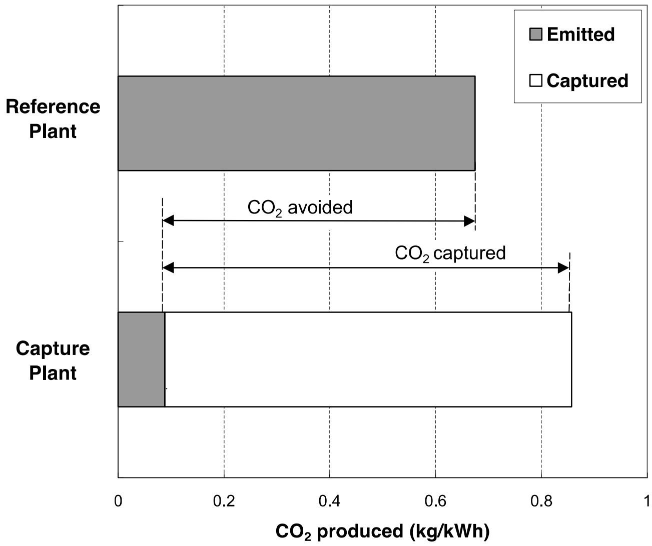


Table 8-13 and Table 8-14 provide a summary of the estimated CO_2 abatement costs associated with CCS for the reference power plants under different scenarios. The cost of CO_2 abatement is the lowest under the highest capture scenario due to economies of scale. These results are presented in Figure 8-6 and Figure 8-7.

Table 8-13 Cost of CO_2 abatement – West Java

	US\$ per tCO_2 captured			**US\$ per tCO_2 avoided**		
	90%	**45%**	**22.5%**	**90%**	**45%**	**22.5%**
No delay with 25 years of operation	73	93	119	101	108	128
5 year delay with 20 years of operation	79	102	130	94	111	136
10-year delay with 15 years of operation	85	98	130	93	102	133
15-year delay with 10 years of operation	85	107	140	89	109	142

Table 8-14 Cost of CO_2 abatement – South Sumatra

	US\$ per tCO_2 captured			**US\$ per tCO_2 avoided**		
	90%	45%	22.5%	90%	45%	22.5%
No delay with 25 years of operation	71	87	113	102	103	120
5 year delay with 20 years of operation	70	87	112	86	96	116
10-year delay with 15 years of operation	74	91	118	82	96	120
15-year delay with 10 years of operation	81	100	131	85	103	132

Figure 8-6 Cost of CO_2 abatement without implementation delay

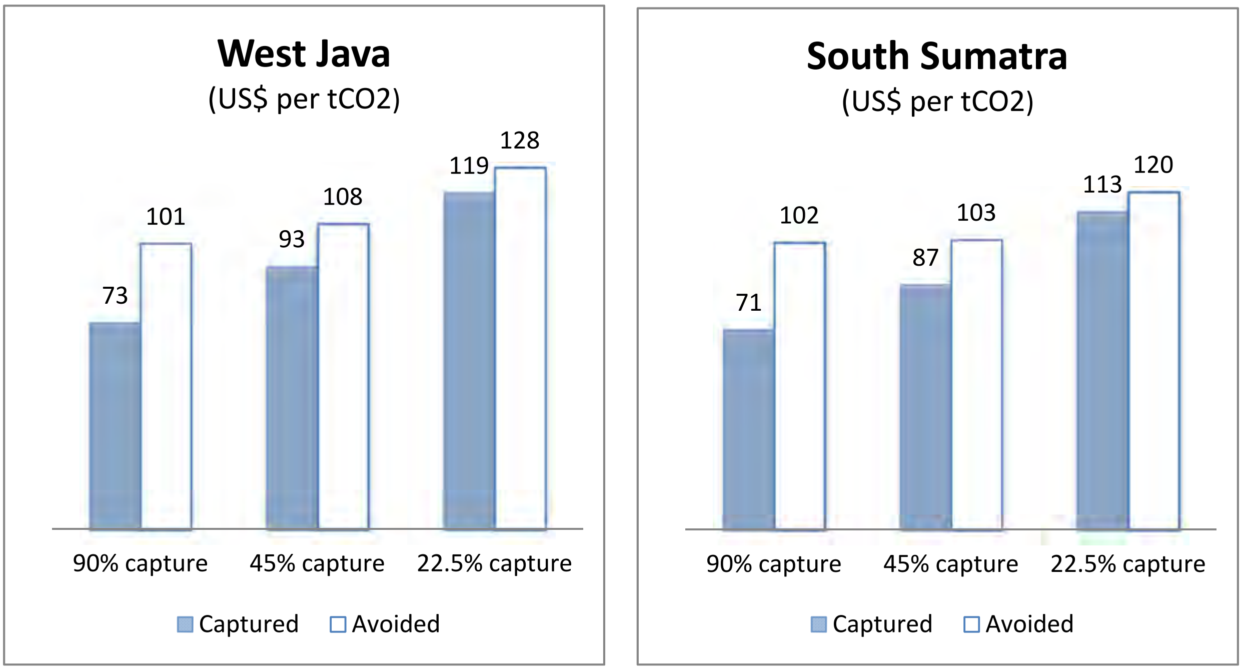
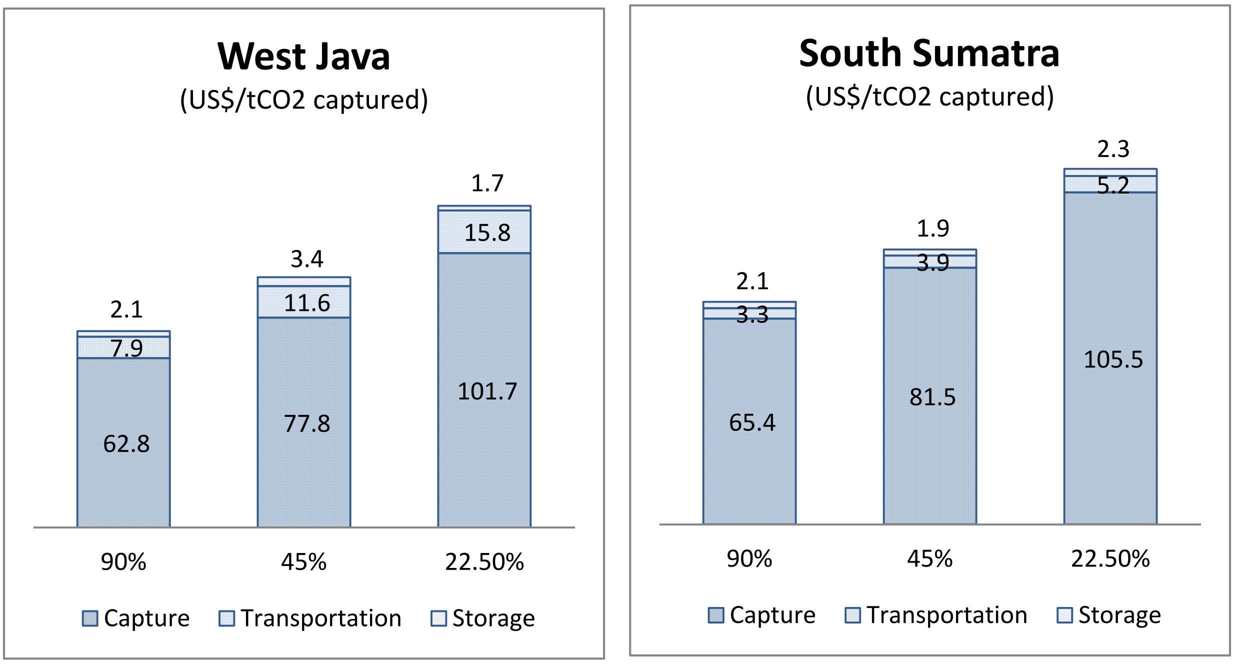


Figure 8-7 Breakdown of CCS CO_2 abatement costs – No delay scenario

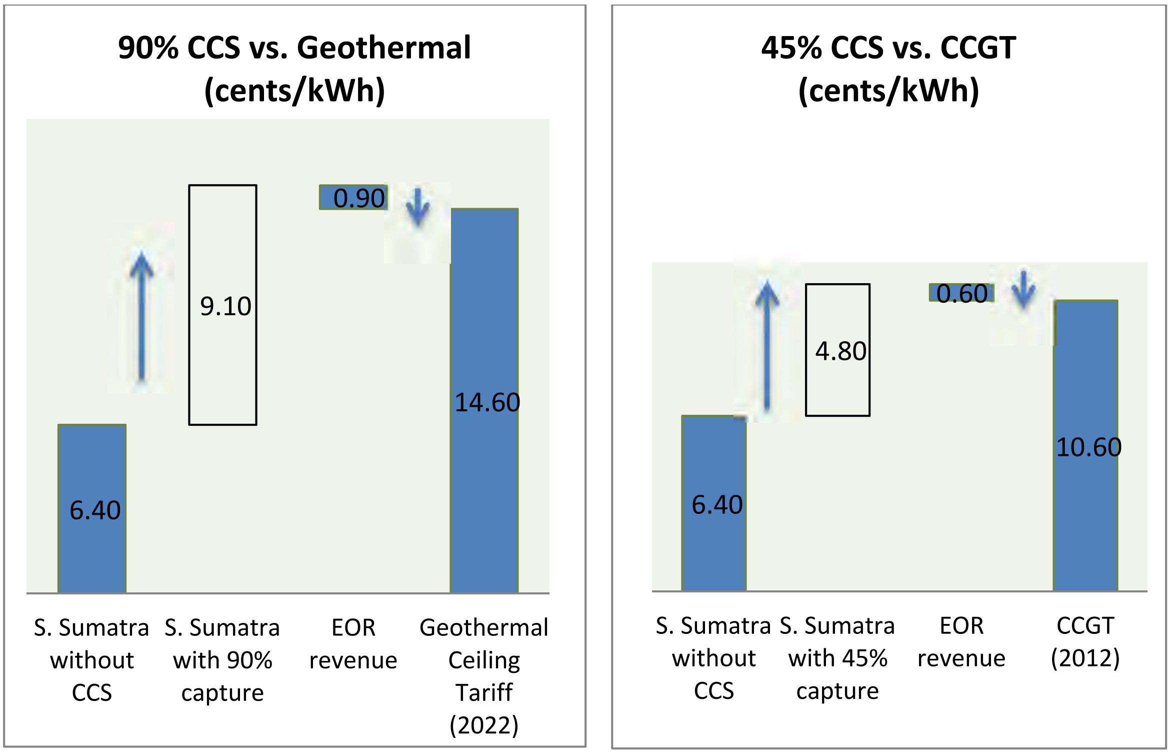


Moreover, the majority of the CO_2 separation cost is incurred due to the energy penalty associated with the CO_2 capture process. Compared with other sources of commodity CO_2, CO_2 captured from coal-fired power plants would be more costly at US$63 to US$105 per tonne of CO_2 captured compared with an estimated levelized cost of US$11 per tonne of CO_2 for natural gas processing. The levelized cost for a natural gas-processing facility capturing CO_2 was estimated at US$28 per tonne of CO_2 captured, including: costs for compressor plus dryer of US$11/t,$CO_2$ captured, pipeline costs of US$11/t CO2 captured, and costs for injection wells of US$6/t CO2 captured (ADB, 2013).

8.7 Cost offsetting mechanisms of EOR

Revenues earned through EOR could offset some of the cost of CO_2 abatement (on a captured basis) associated with the CCS on a dollar to-dollar basis. A small amount of EOR revenue (an equivalent of under US$10 per tCO_2 at the gate of the plant) would bring the LCOE of the South Sumatra plant with 90 percent CO_2 capture down below the ceiling price for geothermal; and LCOE with 45 percent CO_2 capture down below PLN's average cost of CCGT in 2012. Figure 8-8 provides an illustration of EOR as a cost-offsetting mechanism for CCS.

Figure 8-8 The cost offsetting effect of EOR



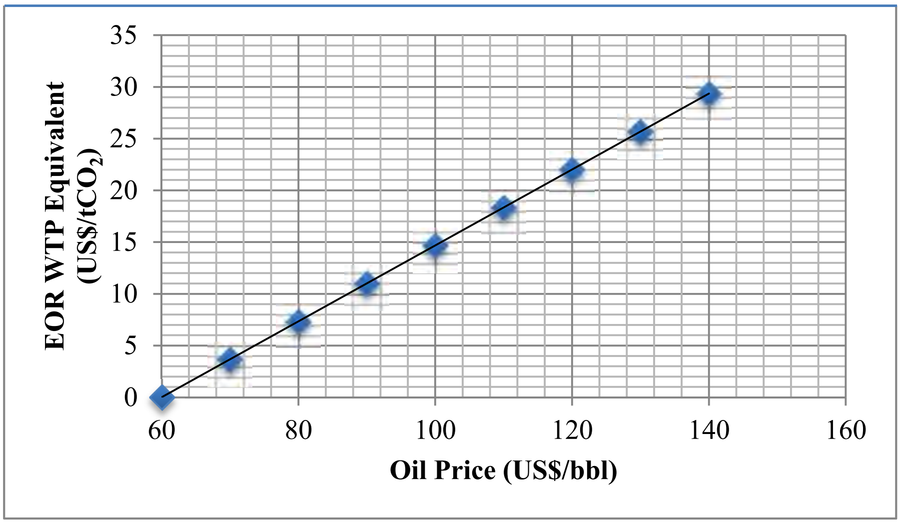
However, several factors will affect the upside of EOR for a power sector CCS project:

<u>The willingness-to-pay for CO_2</u>

This is a function of the market price of oil, the breakeven cost of oil production, and the output ratio between CO_2 input and oil output. Thus, the volatility of the oil price is one of the key risk factors to the upside EOR. Figure 8-9 (Source: ADB 2009) illustrates the corresponding willingness-to-pay for CO_2 at a breakeven cost of oil supply at US$60/bbl.[17]

[17] The abbreviation "bbl" denotes oil barrel.

Figure 8-9 Relationship between oil price and EOR Price



<u>The cost of delivery of CO_2 to the EOR sites</u>

This delivery cost is a function of the distance between the CO_2 source and the EOR sites, and the utilization level of the pipeline. In some cases, such as West Java to South Sumatra, the long distance of the CO_2 delivery route would render EOR opportunities unattractive.

- A long (416 km) transmission pipeline would be needed to transport the CO_2 captured from West Java to a regional hub in South Sumatra. Additional long distribution pipelines are needed to deliver the CO_2 from the regional hub to the EOR sites;
- The scarcity of the CO_2 demand and the skew of the CO_2 demand curve alone would lead to considerable decrease in EOR pipeline utilization in the later years of the CCS operation. For example, even without the presence of any competition, the EOR pipeline from West Java in the 90 percent capture scenario would only be able to operate at a relatively high capacity for the initial few years before becoming redundant. Competitive pressure would further reduce the capacity utilization of the pipeline; and
- Additional CO_2 delivery routes to other CO_2 storage sites are thus needed to transport the remaining CO_2 to the storage sites. The fluctuation in the demand for CO_2 for EOR will inevitably affect the quantity of CO_2 transported in, and thus would also affect the capacity utilization of the alternative pipelines.

<u>Competitive sources of CO_2 and availability of lower cost CO_2 by-products from other sectors</u>

Lower-cost CO_2 supplies from natural gas facilities will likely be the first mover in the EOR market, and crowd out the CO_2 captured from the power sector. The cost of capturing CO_2 as a by-product of natural gas processing is considerably lower (at around US$11 per tonne of CO_2) than CO_2 captured from coal-fired power plants (at more than US$60 per tonne of CO_2). Therefore, the natural gas sector operations face a lower hurdle to respond to the same policy incentives associated with CO_2 abatement.

8.8 Benefits of CCS

A coal-fired plant generates both local pollutants (in the form of NOx, SO_2 and particulates) and a global pollutant (CO_2). The CCS process would reduce the emissions of all these global and local pollutants. Thus, the benefits of CCS can be viewed in terms of the avoided costs of the global and local pollutants abated. Moreover, the implementation of CCS will also generate added benefits in terms of local and global employment, an aspect that is not quantified in this analysis.

8.8.1 Positive global externality

Global environmental benefits represent the avoided cost of CO_2 emissions. There is a general lack of consensus view on the cost of CO_2 emissions. Although costs of CO_2 emissions under the European Union (EU) Emissions Trading Scheme are currently around €7/tonne, and the medium-term prices are expected to rise. In the Guidance Note on the "Social Value of Carbon," the United States Department of Energy (USDOE, 2013) and the World Bank have provided the following projections of the economic damages associated with CO_2 emissions: roughly at US$30/t$CO_2$ by 2015, US$35/t$CO_2$ by 2020, US$42/t$CO_2$ by 2025, and US$50/t$CO_2$ by 2030.

8.8.2 Positive local externality

Three studies were considered to estimate the cost of local negative externalities associated with coal-fired power plants. A recent study for the Suralaya coal-fired power plant (Liun, 2013) estimates a range for the monetary cost of the negative externality for NOx, SO_2 and TSP between US$0.0020/kWh and US$0.00646/kWh in 2000 US dollars. Two other studies from China and Australia were also considered. The China study is a joint study by the China State Environmental Protection Agency (SEPA) and the World Bank, and the Australia study is by the Australian Academy of Technological Sciences and Engineering (ATSE). The negative impacts of pollution on local inhabitants were measured by the benefit transfer method, using studies from other countries and adjusting for the Gross Domestic Product (GDP) per capita.

Table 8-15 shows the results of the three studies. The estimates of the Suralaya study are between those provided in the China and Australia studies. The range is wide, with the adjusted estimates based on the China study being lower and the adjusted estimates of the Australia study being higher than those of the Suralaya study. An average of the low and high estimates for Suralaya, (US$0.0042 per kWh) could be inflated to US$0.007 per kWh using IMF inflation factors (IMF, 2014).

Table 8-16 Estimates of the cost of local externalities

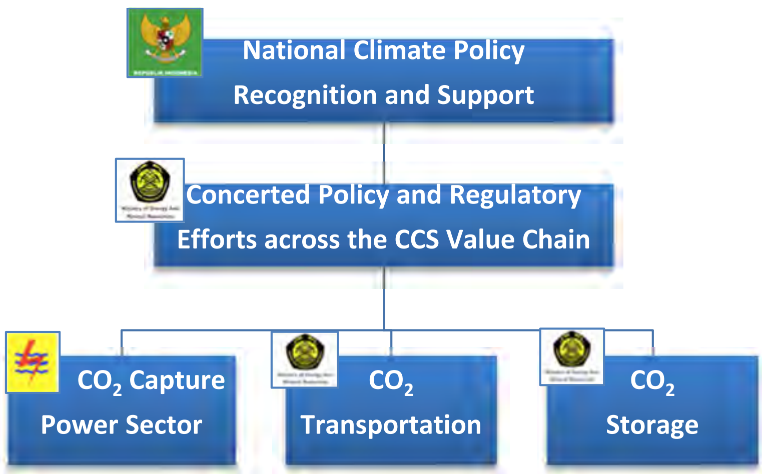
(2000 USD/kWh)	**Suralaya Study**	**China Study**	**Australia Study**
TSP	n.a.	0.00103	0.00135
SO_2	n.a.	0.00018	0.00735
NOx	n.a.	0.00000	0.00500
Total	**0.0020 - 0.00646**	**0.00131**	**0.01370**

9. INSTITUTIONAL READINESS

This chapter explores the institutional and regulatory aspects of CCS implementation from the perspective the CCS "value chain" involving three distinct processes: capture, transportation and storage.

Unlike other climate-smart technologies in the power sector, such as renewable-based power generation, CCS is unique in that the CO_2 abatement process cannot be accomplished in one integrated step alongside power generation. It requires the successful implementation of three sequential steps, starting from the capture of CO_2 at the power plant level, to transportation, and then to the deep underground storage of the CO_2 captured. The CCS value chain involves operators both within and outside the power sector, thus posing some unique institutional challenges. Each step of the CCS operation requires the facilitation of appropriate institutional, legal and regulatory frameworks, as illustrated in Figure 9.1, to govern the structure, operations, ownership, management and monitoring of the process -- all of which still need to be established.

Figure 9-1 CCS Development Framework



Moreover, unlike most alternative technologies, CCS is still in its infancy. Before entering commercial scale applications, CCS technology is yet to be tested out in small-scale pilot projects in Indonesia. A CCS policy mechanism, along with a CCS Road Map tailored to the stage of technology development, would help to develop a regulatory environment that fosters CCS development in Indonesia. The power sector should play a strong role in the development of this road map.

Meanwhile, in anticipation of potential future adoption of the technology at a commercial scale, the power sector needs to reach a certain level of "readiness" on the strategic, technical, institutional and financial fronts. However, the current absence of policy-level instructions on the issue has led to many practical challenges in implementing CCS-R measures at the power plant level today. Without clear regulatory mandate or policy-induced financial incentives, it is difficult to incorporate CCS-R requirements, such as space provisions, layout and design modifications, etc. into the IPP procurement process.

Last but not least, none of the above mentioned adjustments would happen without a formal adoption of CCS as one of the emission reduction measures in the national climate policy in Indonesia. Once CCS is formally included in the list of climate-smart technologies, many existing policy levers, such as feed-in-tariff, portfolio standards, etc., as proven effective in the renewables arena, could be applied to CCS and CCS-R in the power sector. Under this policy environment, CCS and CCS-R decisions can be made on the technical feasibility and economic merits of the investment.

9.1 Gaps in the National Climate Policy

As part its global commitment to combat climate change, the Government of Indonesia pledged in 2009 to reduce GHG emissions by 26 percent from a business-as-usual level through domestic efforts by 2020, and pursue a further 15 percent reduction with international support.

The only official document published by the GoI that governs the national policy on Climate Change is the Presidential Regulation (PR) No. 61 of 2011 regarding the National Action Plans on GHG reduction (RAN-GRK). RAN-GRK was developed to provide guidance for ministerial agencies on the policy and strategy that are needed to reach the 26 percent and 41 percent emission reduction targets by 2020. RAN-GRK laid out the largest contributors to GHG emission reduction as forestry and peat land use, followed by transportation and energy sectors. However, the emission reduction targets set forth by RAN-GRK for the power sector were modest, and did not include limitation of GHG emission from fossil power plants.

The RAN-GRK listed directives to support the action plans in the transportation and energy sectors, which pertain to: energy conservation, utilization of cleaner fuel (natural gas), increased utilization of renewable energy (small hydro, biomass, solar, wind), utilization of "*clean technology for power generation*", and development of low-emitting mass transportation systems. However, there is no further explanation of the "*clean technology for power generation*" in RAN-GRK. Key technologies to reduce CO_2 emission from fossil power generation, such as USC coal power plants, IGCC or CCS, are not indicated in RAN-GRK.

As described in Chapter 2, Indonesia's dependence on fossil fuels, particularly coal, will grow rapidly instead of declining. CCS provides a potential way to address Indonesia's Climate Change targets in a way that power plant efficiency enhancements cannot.

9.2 Gaps in the power sector

9.2.1 Sector Regulation Overview

<u>Public and private players in the power sector</u>

The Indonesian power sector is regulated by the Electricity Law No.30 of 2009, which stipulates that electricity provision to the public is governed by the State, and that the provision of electricity is a responsibility of the GoI. In doing so, the GoI authorizes a state-owned enterprise (SOE) and regional government-owned enterprises to undertake the electricity supply business. In reality, there is only one SOE authorized by the GoI to conduct electricity business throughout the country, which is PLN. There have been no regional government-owned enterprises yet in the power business. Private enterprises, cooperatives and community organizations can also participate in the electricity supply business, but only through PLN.

PLN is the only SOE in the electricity business in Indonesia with exclusive concession and license granted by the government to carry out a vertically-integrated business spanning across generation, transmission, distribution and sales of electricity. The concession is defined in the Law by the activity of electricity distribution and/or sale to end customers. The concession area granted by GoI to PLN is throughout the territory of the Republic of Indonesia, except in a few smaller isolated areas or pockets where concessions are granted by GoI to some other entities. As the owner of the exclusive concession areas, PLN has been acting as the "single buyer" of all electricity produced by the Independent Power Producers through PPAs. The electricity generated by IPPs and by PLN's own generation would be transmitted and distributed to end consumers through the high voltage (HV) transmission and medium voltage distribution grids owned by PLN.

PPAs between IPPs and PLN have been the business model that makes private sector participation quite successful in Indonesia. As of December 2012, about 27 percent of the total generation capacity supplying the HV grid is owned by IPPs, with the remaining 73 percent owned by PLN (DGE, 2013). It is expected that participation of IPPs will continue to increase in the future, in line with PLN's limited financing capacity for funding massive power generation projects.

A PPA contains legal, commercial and operational aspects. Once a PPA is signed by an IPP and PLN, all those aspects are fixed and binding over a 25-year term. Various risks associated with IPP development and operation would be allocated either to the IPP developers or to PLN on the principle that the party that has the most control over a risk shall take the risk. A typical risk that is allocated to PLN is the government risk, which includes government force majeure and change of laws and regulations.

According to the regulation, the purchase price from the IPP by PLN in the PPA has to be approved by MEMR. A scheme of government guarantee can be provided by the GoI via the Ministry of Finance to cover non-payment risk by PLN if the IPP project is a Public Private Partnership (PPP), or if the IPP project is included in a government program, such as the "fast track program".

Tariff setting scheme

The Electricity Law No.30 of 2009 also stipulates that the electricity tariff is set by GoI with approval from the Parliament. Due to considerations of public service obligations (PSO), the tariff has been traditionally set at a lower level than the cost of supply, resulting in a considerable PSO subsidy paid by the government to PLN, whose cost of production remains a subject of hot debate by the Government and Parliament every year. The PSO subsidy is only granted and allocated from the state budget each year after a thorough audit of PLN's performance.

Recent developments in the tariff policy of the new government have indicated that the GoI would soon implement tariff rationalization in order to make the tariff more cost reflective for all consumer categories, except those under-privileged people who consume a small amount of lifeline electricity. The tariff rationalization would bring the tariff to an economic level that reflects the actual cost of supply, and would be automatically adjusted according to inflation, changing oil price, and movements in exchange rates.

Role of CO_2 emissions reduction in the power sector master plan

At present, there is no law or regulation limiting the amount of CO_2 emissions from fossil-fuel power plants in Indonesia.

RUPTL, which is a strategic power development planning document issued by PLN and endorsed by the GoI annually, does not internalize the cost of CO_2 emissions in the planning process, resulting in power development plans dominated by coal as the lowest cost base-load generation throughout the country. In the business model, the cost of emission has not been reflected in the cost structure of the electricity supply.

Due to a lack of regulatory pressure, the issue of CO_2 emissions has not entered the discussion between IPPs and PLN during the PPA negotiations for coal-fired power plants. Without any regulatory mandate or policy incentive, PLN cannot insert in a PPA contract clauses related to CO_2 emissions reduction, or specific requirements for the power plant to become CCS-R.

9.2.2 Impact of CCS-Readiness on IPP Projects

The incorporation of CO_2 capture into the coal-fired generation process will bring considerable alterations to the commercial aspects of PPAs for the following reasons:

Reduction of Net Dependable Capacity (NDC)

NDC is the basis for calculating the capital cost recovery (CCR), or fixed capacity charge, or capacity payment. This is the component in the PPA that generates real income for an IPP. If the NDC were to be reduced by 25 -30 percent due to CO_2 capture being implemented, PLN would still have to pay the full capacity payment, as the IPP would not be willing to accept lower capacity payments that cause lower revenues. In other words, PLN would have to take the risk of implementing CCS in IPP projects. In the PPA, a new ruling that obliged IPPs to install and operate CCS after the PPA has been signed would be categorized as a "change of laws" risk. Such a risk would be borne by PLN.

A higher capacity payment by PLN to an IPP plant equipped with CCS would be reflected in the overall cost of electricity production. This higher cost would either be passed through the electricity tariff to end consumers (if the GoI has a policy to pass the higher cost to the people through a higher tariff), or would necessitate government subsidizing the tariff (if the GoI does not intend to pass the cost on to the people). Either way, the GoI would need a legal and regulatory framework that allows the government to adopt such policies.

Additional investment incurred from installing CO_2 capture equipment

All investments in IPP projects would eventually have to be repaid by the off taker, which is PLN. The additional cost incurred in installing a CO_2 capture system would be added to the fixed capacity payment and hence the CCR. Before CO_2 capture equipment is procured by an IPP, say in year 5 of operation, PLN might have to agree on the additional cost component in the CCR. Negotiations between IPPs and PLN could take time, and according to the current regulation on IPPs, the new purchase price by PLN would have to be approved by MEMR.

Deterioration of Plant Heat Rate

Heat rate is one performance indicator in the PPA that must be guaranteed by the IPP to PLN, as it will greatly affect the quantity of coal consumed to produce each unit of electricity. Since the cost of coal supply is passed through by the IPP to PLN, PLN must be prepared to accept the deterioration of heat rate if CCS is implemented. Deterioration of heat rate could be predicted on an engineering basis using heat and mass balance calculations, but the commercial heat rate might have to be eventually negotiated between PLN and the IPP.

Additional land provision

The installation of CO_2 capture equipment will require additional provision of land while land is becoming ever scarcer, especially in populous demand centers, such as Java. Land for new thermal power plants is subject to competition across all sectors. Land availability for CO_2 capture is not a particular issue for the West Java power plant considered in this study because PLN had already acquired the land many years ago, and that land is sufficient to accommodate the construction of two coal power generation units (2x1000 MW) along with a sizable coal yard, fly ash pond, and any space needed for installing CO_2 capture equipment in the future.

However, that case should be considered as an exception rather than the norm. For any new power plant to be built, either the IPP developer or PLN will be responsible for acquiring the land. Additional land requirement for CO_2 capture may pose a considerable challenge in terms of the land acquisition process, and at times may not even be feasible especially in land-scarce demand centers. With no regulatory framework in place requiring new coal power plants to be CCS-Ready, it would be difficult to convince an IPP developer to acquire additional land to make provision for future retrofit of CO_2 capture equipment.

Pre-emptive power plant design

For a power plant to be CCS-R, certain design considerations need to be incorporated in the design phase. For example, the spacing between the economizer and the air preheater needs to be carefully planned in anticipation of the future retrofit of NOx removal equipment (SCR) in that space. Other examples include the provision of space for the future installation of high performance FGD and CO_2 capture equipment, as well as compressors for CO_2 delivery. On a more fundamental level, the layout of the steam turbine hall needs to accommodate future needs for extracting steam for the CO_2 capture process.

Impact of the lack of a policy framework

Many of the practical challenges that PLN is confronting today in incorporating CCS-R requirements in the IPP procurement process, follow from the lack of a policy framework on curbing CO_2 emissions from fossil-fuel-based power plants. Not surprisingly, with looming power shortages and delays in transmission projects, PLN sees no particular reason to further complicate the IPP process by requiring the IPP developers to make additional provision of land or any design modifications. Moreover, without a regulatory framework, it would also be challenging, if not entirely impossible, to assign responsibilities and allocate risks amongst the players. At a practical level, it is also difficult to make provisions for tariff changes in a PPA. The CCS-R experience in the developed world can also shed light on the unique challenges the power sector faces in implementing CCS-R (Box 9-1).

Box 9-1 CCS-Ready experience in the UK

1. Capture Readiness

Since about 2006 there has been an acknowledgement in the UK that new coal or gas power plants should be constructed in a way that avoids barriers to the subsequent installation of CO_2 capture equipment. The intent is to avoid locked-in CO_2 emissions throughout the lifetime of the power plant. This concept has become termed Capture-Ready. However, the formal definition of Capture-Ready has lagged behind the practical consideration of the implications of pursuing the intent.

There have been nine new power plants built in the UK under this regime. All of them are natural gas combined cycle gas turbine power plants. They have a combined generation capacity of 8,500 MW. There has been no test case in the UK of a coal-fired power plant being built as Capture-Ready.

The regulatory mechanism for requiring Capture-Readiness is through the permitting and licensing process. Rather than an obligation to meet specific quantified criteria, the power plant proponents are required to present a reasonable CCS feasibility study plan, which is then judged in a subjective way by the licensing authorities. This approach has resulted in inconsistent outcomes.

An example is the license conditions for 2006/7 West Burton CCGT station which state: *"The layout of the development shall be such as to permit the installation of such plant as may reasonably be required to achieve the prevention of discharge of carbon and its compounds into the atmosphere."* Not only is this license condition vague, but the use of the word "prevent" implies 100 percent CO_2 capture, which is technically impossible.

In 2009 the UK Government issued Guidance notes on CCS-Readiness (Carbon Capture Readiness – A Guidance note for Section 35 Electricity Act 1989 consent applications UK Department of Energy and Climate Change, Nov 2009). Applicants for power plant consents are required to prepare a feasibility study which includes demonstrating:

- The technical feasibility of retrofitting their chosen carbon capture technology; and
- That sufficient space is available on or near the site to accommodate carbon capture equipment in the future.

2. Transport and Storage Readiness

The feasibility study should also include an economic assessment and should demonstrate:

- That a suitable area of deep geological offshore storage exists for the storage of captured CO_2 from the proposed power plant; and
- The technical feasibility of transporting the captured CO_2 to the proposed storage area.

In 2006 the British Geological Survey published CR/06/185N "Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK". This is the standard reference for the identification of suitable storage locations. This report quantifies storage capacity for 7,500 million tonnes of CO_2 in offshore hydrocarbon fields and a further 15,000 million tonnes of quantified CO_2 storage capacity in deep offshore saline aquifers. Potential onshore CO_2 storage capacity is much less, in smaller fields and subject to tighter planning controls. It is also likely to be in demand for Natural Gas storage. So the UK CCS-Ready requirements specify only offshore geological storage.

The nine CCS-Ready gas-fired power plants built to date in the UK have the combined potential to capture about 23 million tonnes of CO_2 per year. The quantified offshore CO_2 storage capacity in hydrocarbon fields is sufficient to accommodate CO_2 at that rate for over 300 years.

Source: UK CCS experts/Stakeholders.

9.3 Gaps downstream in the CCS value chain for CO_2 transportation and storage

LEMIGAS (LEMIGAS, 2010) identified existing legal and regulatory frameworks that could be adapted for national regulatory development, with unique emphasis on the transportation and storage end of the CCS value chain. A key finding of that study was the complexity of the CCS value chain and the cross-cutting nature of the regulatory regimes that the value chain occupies.

At present, there are no existing laws and regulations governing CO_2 pipelines, neither are there any with respect to the ownership, grant, or lease of subsurface pore space for CCS. For cost-offsetting mechanisms, such as EOR, there is no clear approach as to how it could be integrated into the production-sharing arrangements for oil/gas development programs.

CCS storage operations require long-term access to both surface and subsurface areas, including access to pore space for storage. In Indonesia, the typical duration of existing land ownership rights associated with production sharing, may be too short for CCS operations, especially with respect to indefinite storage. This is further complicated by the restriction on the mineral rights, which only GoI has the power to grant.

Some unique aspects of CCS include the need for long-term stewardship of the CO_2 and potential liabilities associated with the operation, including environment and health risks, and potential leakage or contaminations. There remains a clear lack of regulatory frameworks in all these areas.

9.4 Policy review

Much of this section is a synthesis of the Regulatory Framework chapter of the Indonesia Country Report *Determining the Potential for Carbon Capture and Storage in Southeast Asia,* prepared by LEMIGAS for ADB.

CO_2 classification

The definition of CO_2, and the process by which it is stored, play a key role in determining jurisdiction in Indonesia. Generally, there are two classifications of CO_2 -- one as an industrial product, also referred to as a resource; and the other as a waste product or pollutant. This distinction is important for Indonesia in the future, because industrial resource recovery projects are usually subject to regulation by existing oil and gas regulations, while waste or pollutant disposal will fall under the jurisdiction of relevant environmental regulations. In the USA, CO_2 is sometimes classified as a commodity and in Canada, sometimes a resource. However, CO_2 is not yet clearly classified in Indonesia (OECD/IEA, 2014).

CO_2 transportation

Although there is no existing law directly addressing the piping of CO_2 in Indonesia, some parallels may be drawn from existing laws and licensing regulations on natural gas pipelines. In Indonesia, BPMIGAS (the former Indonesian oil and gas industry regulator) was in charge of awarding concessions for upstream natural gas pipeline construction and operation. Generally, a concession is awarded on a competitive basis for up to 20 years, at the end of which ownership will revert to the state. Under a concession awarded as a production sharing contract (PSC), contractors would build and operate the pipeline but ownership of the pipeline would belong to the State. Similar arrangements could apply to the construction and operation of CO_2 pipelines for CCS operations.

Surface rights and subsurface rights pertaining to CO_2 storage

The transportation and storage of CO_2 require access to both surface areas for the installation of pipeline and storage facilities, and subsurface areas for the injection and storage of CO_2.

Rights to subsurface and offshore areas are of particular importance to CCS storage operation. In Indonesia, the state, acting as the custodian for the Indonesian people, owns the right to mineral resources and subsurface areas. In turn, the State also grants usage rights for the exploration and exploitation of mineral rights for limited periods under *Hak Pakai* or leasing concepts. In the oil and gas sector, exploration and exploitation rights take the form of PSCs between oil and gas operators and regulators. Rights to storage space would similarly require a specific contract from the State or to be derived from an existing contract, such as a PSC or other rights. The limited time duration of these contractual rights would pose issues for long-term storage of CO_2.

Long-Term Stewardship and Liability for Stored CO_2

Although there is no existing law or regulation governing the long-term stewardship of CO_2 and associated liabilities in Indonesia, existing regulations on upstream oil and gas reservoir management and injection of wastewater in oil and gas operations may help guide the development of similar regulations for CO_2 storage and EOR operations. For example, Regulation13, on the protection of underground water resources, specifies that field operators may apply for five-year renewable permits from the Ministry of Environment for re-injecting wastewater into a production field. The application must be accompanied by necessary supporting documents which:

- Indicate the injection zone's ability to absorb the matter injected;
- describe the selection criteria and the construction and operating procedures for the injection wells; and
- provide proof of structural integrity and absence of leakage of the pipeline and the associated reinjection field.

The wastewater regulation also requires the operators to properly seal the reinjection wells based on a closure plan, with specifications on the plugs and cement used for well closure.

Other oil and gas practices

Other oil and gas practices relevant to CCS include production sharing contracts that govern all public and private activities taking place on the oil and gas fields, which would also apply to CCS activities taking place in oil and gas fields. Related to PSCs, government Regulation No. 35, 2004 on Upstream Oil and Gas Activities and Article 39 of the regulation provide more specific guidance on the environmental aspects and liabilities associated with PSCs. Likewise, existing oil gas regulations related to the transportation and injection of gas as part of the hydrocarbon production/recovery process, as well as existing regulations on upstream oil and gas activities and reservoir management, are all relevant to CCS operations.

9.5 Recommendations

In light of the above discussions, the team recommends:

Creating an enabling policy environment

- Incorporating CO_2 emissions reduction from fossil-fuel power plants as one of the measures in the national climate change policy;
- Including CO_2 emission reduction from coal-fired power plants into the power sector master plan; and
- Making concerted efforts along the CCS value chain, via creating a corresponding regulatory framework, to enable not only CO_2 capture in the power plants, but also facilitate the processes of CO_2 transportation and storage.

Bridging the financial and technical viability gap

- Providing necessary policy incentives to help bridge the economic viability gap associated with CCS, while tailoring policy incentives to the stage of technology development (see **Box 9-2** on the policy incentives at different stages of CCS technology development);
- Considering extension of the existing regulations (such as feed-in-tariff for renewable energy) which could be extended to include CCS and CCS-R to provide IPPs with the necessary price certainty and guaranteed off-take for their consideration of CCS and CCS-R options.
- Reducing the associated risks and costs of CCS through pilots and demonstrations where the power sector should aim to play an important part;
- Removing the lack of experience by showing technical feasibility through pilot and demonstration projects in Indonesia. Also, by replicating the CCS projects in many places in the world, reduction of cost and energy penalty can be expected by the development and improvement of capture technologies. (see Figure 9-2 for the Indonesia CCS Road Map);
- Integrating the power sector into the current CCS Road Map (developed by Government /LEMIGAS), and selecting or soliciting power plants. Presently, the CCS Road Map focuses on the oil/gas sector. The roadmap should show the timeline of pilot, demonstration and commercial deployment of CCS projects in the power sector. Indonesia can provide the opportunity of CCS at coal-fired power plants for donors to provide funds for pilot demonstrations because there are many coal plants planned in the development

plan of PLN. IPP developers can consider participating in such projects when adequate financial incentives are given; and

- Building awareness of and capacity in CCS and CCS-R implementation while managing public perception. Joint effort is needed among Government, Lenders, and Donors for dissemination and capacity building of CCS. The Inter-ministerial Working Group for CCS deployment is already formed focusing on the oil/gas sector. The Group should be extended to include the Power Sector CCS development and deployment.

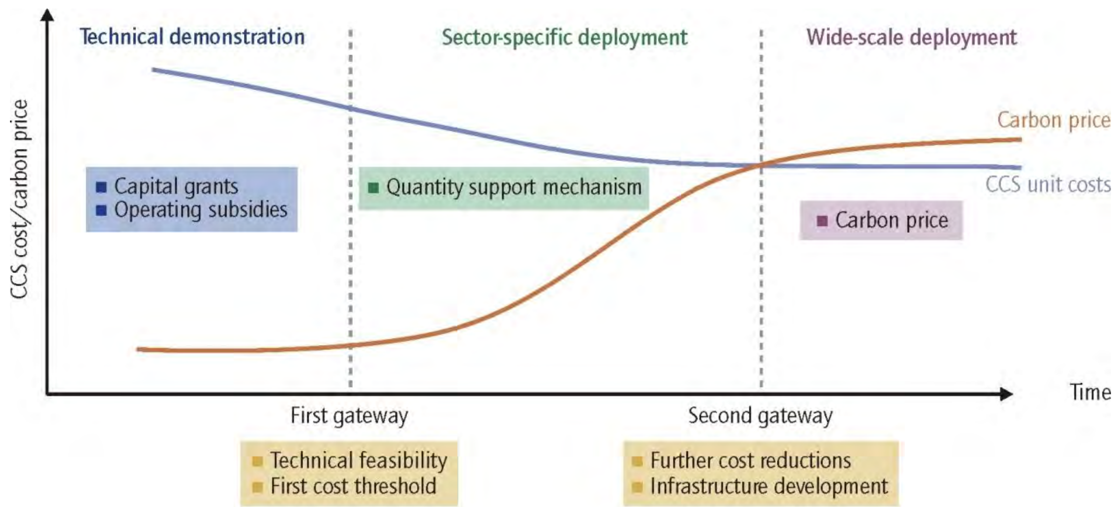
Box 9-2 Tailoring CCS policy mechanisms to the stage of technology development

A key challenge for policy makers is to enable support mechanisms to evolve to reflect developments in technology, while ensuring the policy certainty and credibility required to drive investment. Today, CCS is in the demonstration phase, and on the cusp of the early deployment phase. Thus, the most effective policy mechanisms will be technology-specific, aimed at advancing technology learning, and promoting access to private capital (as opposed to driving emissions reductions *per se*). These include mechanisms such as capital grants, production subsidies, investment and production tax credits, credit guarantees, feed-in-tariffs and portfolio standards. As CCS technology progresses, policy emphasis will shift to emissions reductions, supporting wide-scale CCS deployment where it is cost effective among other abatement options. Policy options include technology-neutral incentive mechanisms such as cap-and-trade schemes, carbon taxes, baseline and credit schemes, fee/rebate systems and emissions performance standards (OECD/IEA, 2012).

The timing of the transition in policy is difficult to determine in advance, because it depends on how CCS and alternative abatement technologies develop. To manage this uncertainty and provide some clarity to investors, governments can establish "gateways" within a stable policy framework, that specifies:

- criteria that define when or if policy will move to the next stage, including potentially performance or cost thresholds;
- policies within each stage; and
- how government will react if gateways are missed.

This figure provides an illustration of possible gateways within a CCS policy framework.



Potential gateways within a CCS policy framework

Source: (IEA, 2012)

9.6 Road Map for CCS Pilot Project Development

Figure 9-2 presents a comprehensive 15-year roadmap that has been proposed as a part of the previous CCS study effort (ADB, 2013), aimed at facilitating and bringing pilot and demonstration projects to larger scale commercial phase. The roadmap includes a timeline for all related CCS activities, and detailed directions for their pilot phases.

To date, there is no project identified or planned to enter pilot or demonstration phase in the power sector. This study is the first effort to facilitate the power sector taking a position on the emerging CCS Road Map.

In Figure 9-2 the timing of each gate decision occurs at the end of the horizontal bar:
Gate 1: Identify CO_2 source and storage site;
Gate 2: Secure funding and complete permitting;
Gate 3: Construction completed;
Gate 4: 50–100 tons/day CO_2 injected successfully; and
Gate 5: Successful pilot assessment to confirm a swift transition to demonstration project (in the same storage reservoir) (ADB, 2013).

9.7 Recommendations

Creating an enabling policy and regulatory environment

National climate policy to recognize CCS as a means of CO_2 emission reduction;

- Endorsement of the CCS Road Map at the national level; and
- Concerted efforts along the CCS value chain: CO_2 capture, transportation and storage

Bridging technical and financial viability gap

- Consider adding CCS-Readiness Provisions in the PPA, such as space provisions and design modifications;
- Provide policy incentives for future CCS implementation;
- GoI to initiate CCS pilot and demonstration activities for the power sector; and
- Power sector participation in the CCS Road Map.

Awareness and capacity building

Develop an Indonesian Centre of Excellence in CCS technology and purpose tasked to:

- build technical and economic assessment capability;
- develop technologies to suit Indonesian conditions;
- run workshops to encourage wide understanding of potential and limitations of CCS; and
- encourage public acceptance of CCS technologies.

Figure 9-2 Road Map for CCS Pilot Project Development

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