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PROSPECT FOR CO_2 EOR TO OFFSET THE COST OF CCS AT COAL POWER PLANTS

PROSPEK CO_2 EOR UNTUK MENUTUPI BIAYA CCS PADA PEMBANGKIT LISTRIK BATUBARA

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ABSTRAK

Integrasi teknologi penangkapan, transportasi, dan penyimpanan CO_2 (CCS) diyakini mampu mengurangi emisi CO_2 secara drastis dari sumber-sumber emisi utama seperti pembangkit tenaga listrik batubara. Namun demikian, perkembangan implementasi teknologi CCS masih sangat lambat karena dukungan skema bisnis yang minim. Pemanfaatan CO_2 hasil separasi untuk peningkatan perolehan minyak (CO_2 EOR) menawarkan suatu skema komersial. Pendapatan dari tambahan produksi minyak dapat digunakan untuk menutupi sebagian biaya investasi integrasi CCS pada pembangkit listrik batubara. Prospek CO_2 EOR untuk mendukung kekonomian suatu proyek integrasi CCS pada pembangkit listrik batubara dibahas dalam makalah ini. Sebagai basis studi, telah dipilih sebuah pembangkit listrik batubara yang diasumsikan mulai menghasilkan listrik tahun 2022. Biaya pembangkit listrik setara (LCOE) tanpa CCS adalah 6.4 sen dolar Amerika per kWh (sen/kWh), menghasilkan emisi CO_2 sekitar 4.1 juta ton per tahun. Integrasi CCS dengan pembangkit listrik batubara akan menambah biaya terkait sistem peralatan penangkapan, transportasi, dan injeksi CO_2 ke dalam reservoar minyak. Evaluasi tambahan biaya berdasarkan skenario separasi CO_2 90%, 45%, dan 22.5% dari gas buang pembangkit. Pada sekenario separasi 90%, LCOE naik menjadi 15.5 sen/kWh terutama akibat tambahan biaya energi untuk proses separasi CO_2. Diperlukan penurunan biaya minimal sebesar 0.9 sen/kWh agar LCOE lebih rendah dari pembangkit listrik panas bumi. Pengurangan persentase separasi menjadi 45% dapat menurunkan LCOE menjadi 11.2 sen/kWh, atau diperlukan pengurangan minimal 0.6 sen/kWh agar menghasilkan LCOE lebih rendah dari harga listrik gas turbin PLN tahun 2012. Pengurangan pada kedua kasus tersebut dapat dicapai jika CO_2 hasil pemisahan dapat dijual kepada operator EOR dengan harga sekitar 10 dolar Amerika per ton pada titik serah lokasi pembangkit. Hasil studi ini relevan bagi Indonesia yang sedang merencanakan pembangunan tambahan pembangkit listrik batubara dalam waktu dekat.

Kata Kunci: *CO_2 EOR, CCS, pembangkit listrik batu bara, LCOE, emisi CO_2*

ABSTRACT

Carbon Capture Storage (CCS) technology has gained confidence in its ability to yield dramatic reductions of CO_2 emissions from large stationary emissions sources such as coal-fired power plants. However, the pace of CCS projects has suffered from a less supportive business case. Utilization of CO_2 for enhanced oil recovery (CO_2 EOR) offers commercial opportunities owing to its economic profitability from incremental oil production offsetting the cost of CCS. This paper describes the prospect of CO_2 EOR offsetting the cost of CCS at a coal-fired power plant. A coal-firedpower plant assumed to be commissioned in 2022 is selected as the basis of this study. The Levelized Cost of Electricity (LCOE) of this plant without CCS is estimated at US$ 6.4 cents/kWh and emits around 4.1 $MtCO_2$/year. Integrating CCS to the selected coal power plant imposed additional costs associated with CO_2 capture, transportation, and storage systems. The incremental costs are evaluated based on separation of 90%, 45%, and 22.5% of CO_2 from the power plant flue gas. Under the 90% capture scenario, the LCOE raised more than double to 15.5 US cents/kWh which is primarily attributed to the energy penalty. A minimal reduction of 0.9 cents/kWh could bring the LCOE down below the ceiling price for geothermal. Reducing the CO_2 capture percentage from 90% to 45% could reduce the LCOE to 11.2 US cents/kWh. Lowering the cost to 0.6 cents/kWh or more for this case would result in the LCOE below the state-owned electricity company's average cost of combined cycle gas turbine in 2012. Selling the captured CO_2 under US$ 10 per tonne at the plant gate could help offset the cost. With numbers of new coal-fired power plants expected to be constructed in the near term, integrated coal CCS power plant with EOR is relevant for Indonesia.

Keywords: CO_2 EOR, CCS, coal power plant, LCOE, CO_2 emissions.

I. INTRODUCTION

Carbon Dioxide (CO_2) generated by fossil fuel power plants and released into the atmosphere is causing significant concern. CO_2 is the primary Greenhouse Gas (GHG) which is believed to be the main cause of climate change. In 2013, around 42% of global anthropogenic GHG emissions from the energy sector were attributed to power and heat generation with emissions from power generation making up the majority. Coal combustion has increased its share of CO_2 emissions from 40% in 2002 to 46% in 2013, while the share from oil has decreased from 39% to 33%, with the share of emissions from natural gas staying approximately stable at 20% (IEA 2015).

At the national level, power generation in 2013 is responsible for about 32% of energy-related GHG emissions and this will increase to approximately 44% by 2050 under a mitigation scenario. The share of GHG emissions from coal combustion will account for 49% by 2050 (Sugiyanto et al. 2015). Coal-fired generation will dominate the additional capacity power plant for decades to come because of the relatively large reserves that exist and their affordability. Coal-fired power plants are responsible for a large percentage of CO_2 emissions among other process plants as they produce heavy carbon content per unit of energy released. Compared to gas, coal is nearly twice as emission intensive on average.

Carbon Capture and Storage (CCS) technology has the potential to yield dramatic reduction of CO_2 emissions from large stationary emissions sources by capturing and storing CO_2 deep underground in geological formations for secure storage. Global modeling efforts by the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA) highlight the importance of CCS in stabilizing the GHG emissions at low levels (IPCC 2014; IEA 2013). Acceleration of CCS development and deployment in the energy sector is a key to limiting the long-term rise in average global warming to well below 2 degrees Celsius (GCCSI 2016). Given the magnitude of CO_2 emissions from coal-fired power plants, the greatest potential for CCS is in the coal power sector. Incorporating CCS technologies at new or retrofitted coal power plants can dramatically reduce up to 90% of associated CO_2 emissions (Saskpowerccs 2016; Cebrucean et al. 2013). Although CCS will likely be a key component of the future energy mix worldwide, the pace of CCS projects has suffered from a less supportive business case.

Utilization of CO_2 for enhanced oil recovery (CO_2 EOR) is one technology being considered to provide a positive business case for CCS owing to its economic profitability from incremental oil production offsetting the cost of CCS. CO_2 EOR has been proven effective for increasing oil production substantially while a consistent amount of CO_2 injected is stored permanently at the same time (ARII 2011; Faltinson and Gunter 2013). Approximately 40% of the injected CO_2 remains trapped in the reservoirs during the CO_2 EOR operations. Additional recovery can amount to 5% to 20% of the original oil in place (OOIP) depending on the characteristics of the hydrocarbon and the reservoir conformance (Usman et al. 2014). Application of CO_2 EOR becomes a key driver for CCS in many parts of the world, particularly in the US and Canada (IPCC 2014; GCCSI 2016). The world's first commercial-scale coal CCS power plant integrated with CO_2 EOR in Saskatchewan Canada, at Boundary Dam Unit 3 plant, become operational in October 2014 (Saskpowerccs 2016). Two additional commercial-scale integrated coal CCS power plants linked to EOR are soon to become operational in Southern Company's Kemper County Energy Facility in Mississippi and at Petra Nova in Texas, both in the USA. The importance of CO_2-EOR as a facilitator for CCS is particularly significant where there is no established financial or regulatory incentive for sequestering GHG emissions.

Coal CCS power plants will be more expensive than an equivalent non-CC plant, due to the increase in energy used to capture, compress, transport, and store the CO_2. A coal-fired power plant with CCS might give raise to electricity price per kWh over twice compared to baseline without CCS (Masaki 2015). The costliest part of the CCS process is the capture of the CO_2. It typically represents around 75% of the overall costs for running and the building of a CCS system (Hammond and Spargo 2014). Overall, the cost of each project can vary considerably. The incremental cost of CCS varies depending on parameters such as the choice of capture technology, the percentage of CO_2 captured, and the distance to and type of geologic storage location. Retrofitting existing plants for CCS is expected to be more expensive compared to building a new plant with CCS from the start. New power plants without CCS can be designed to be CCS-ready so that the cost of later retrofitting the plant for CCS will be lower.

Although coupled coal power plants with CO_2 EOR have been established commercially, a very limited literature is readily available covering the potential of CO_2 EOR to defray the costs of CCS at coal-fired power plants. Commercial structures for an integrated coal-fired power plant with CCS combined with CO_2 EOR have been discussed (Agrawal and Parsons 2011), however this only focused on the alternative contract type that link the involved entities in the fluctuating price of oil recovered. The prospects for CCS facilities installed to coal-based power generation in Indonesia have been assessed (Masaki 2015), addressing the conditions under which coal-based power generation could be deemed as CCS-Ready.

This paper assesses the prospect for CO_2 EOR offsetting the costs of CCS facilities coupled to a coal-fired power plant. The assessment is based on analysis of coal-fired power plant design proposed in the Electricity Supply Business Plan (RUPT 2013-2022) that will be built in South Sumatera located near a coal mine. In South Sumatera, excellent opportunities exist for CO_2 EOR sequestration application. The objective of this paper is to examine whether the supply of CO_2 for EOR is a potential means of lowering CCS costs and potentially aiding project financial feasibility. With numbers of new coal-fired power plants expected to be constructed in the near term, integrating a coal CCS power plant with EOR is relevant for Indonesia. Results of this work should be of interest to a broad audience interested in reducing CO_2 emissions such as policy-makers, government agencies, project developers, academicians, and civil society and environmental non-governmental organizations in order to enable them to assess the role of CO_2 EOR as a major carbon management strategy.

II. METHODOLOGY

The project analyzed in this study is an integrated project that includes the entire CCS value chain of capture, transport, and storage of CO_2. The CO_2 captured from a coal-fired power plant, is transported via a dedicated pipeline to oil fields where it is injected for EOR and subsequently stored. Evaluation of the prospect for CO_2 EOR offsets the cost of CCS at such a project takes the following approaches: determining the reference coal-fired power plant and its Levelized Cost of Electricity (LCOE) without CCS, evaluating the incremental cost of CCS on the LCOE under different scenarios, making a comparison of the reference coal CCS power plant to alternative technologies on a LCOE basis, and assessing the economics of EOR as a cost-offsetting mechanism for a coal CCS power plant. LCOE is a measure of a power source which allows comparison of different methods of electricity generation on a consistent basis. It is an economic assessment of the average total cost to build and operate a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime.

A. LCOE without CCS

The coal-fired power plant referenced in this study is selected based on the following set of criteria: the power plants targeted should be large units (>600 MW), the space availability for subsequent CO_2 capture and compression equipment installation, the choice of plants expected to begin operation in 2018 or later, that it should be representative of Indonesia's generation mix, and the availability of CO_2 storage in the region. Baseline performance parameters of the selected plant are derived from prefeasibility studies, expert views, and literature sources. Economic analysis is 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. LCOE of without CCS for the nominated coal-fired power plant is derived to allow consideration of the incremental cost with CCS.

B. Incremental Costs of CCS

CCS coupled to coal-fired power plants will impose additional costs associated with CO_2 capture, transportation, and storage systems. The costliest part is CO_2 capture equipment. It typically represents around 75% of the overall costs for the running and the building of a CCS system (Hammond and Spargo. 2014). Post-combustion capture is applied in this study for capturing CO_2 from the exhaust gases of coal fuel combustion. This technique is the most developed technique employed in industry (Spigarelli and Kawatra, 2013; Wang et al. 2011). The incremental costs of CCS are assessed based on the separation of CO_2 from the power plant flue gas using an amine scrubbing process, supported by flue gas cleaning processes, and liquefaction of the captured CO_2 for transportation to geological storage locations (Masaki 2015).

Captured CO_2 is transported via a dedicated pipeline to oil fields where the CO_2 is injected for EOR. Incremental costs required for CO_2 transmission and distribution are assumed to be US$50,000 per kilometer per inch in diameter for on-shore pipelines. Cost associated with CO_2 well injection is assumed to be US$3 million per work-over of each depleted well, plus US$1 million per well in potential liabilities. Annual Operating and Maintenance (O&M) for CO_2 transportation and CO_2 storage of 8% respectively are adopted. These costs are based on overseas EOR experience (ARII 2011). All the incremental costs are then presented on an LCOE basis.

C. LCOE Comparison

Comparisons are carried out between coal-fired power plants plus CCS with other types of low carbon power generation in terms of LCOE. Data used for this comparison is based on the average cost of supply according to generation type issued by state-owned electricity company (PLN) in 2013 as given in Table 1 (PLN Statistics, 2013). PLN's weighted average cost of supply in the year was at around 11.04 US cents per kWh. Of all the generation technologies, hydro and coal (steam) presented the lowest cost of supply. The average cost of coal-fired generation was 6.58 US cents per kWh compared with the estimated 6.40 US cents per kWh from the reference South Sumatra plant used in this study. The next tier of technologies in terms of cost of supply was geothermal at 10.10 US cents per kWh and combined cycle gas turbine (CCGT) at 10.60 US cents per kWh. According to the Ministry of Energy and Mineral Resource's Regulation 17/2014, the ceiling price for geothermal in Java and Sumatra commissioned in the year 2022 is set at 14.6 US cents per kWh.

D. CO_2 EOR as Cost-Offsetting Mechanism

Revenue from selling captured CO_2 as a commodity to EOR operators could help offset the incremental costs of a coal-fired power plant that adopted CCS. The approach to assess the potential of CO_2 EOR defraying CCS costs is a function of investment of CO_2 captured, transportation, injection, O&M costs, and incremental oil. To estimate the CO_2 value for EOR, the following works are required: identifying individual and/or clusters of

Table 1
Average cost of supply from different generation technologies

Technology	Cost (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	10.60
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**

Notes: exchange rate at IDR 10,930 = US$ 1.00

oil fields that are suitable for EOR surrounding the reference plant, assessing the CO_2 demand profile within a specific period, estimating incremental oil produced, and determining the capital and operating costs for injection of CO_2 into the targeted reservoirs. In addition, the availability of CO_2 for EOR from other, cheaper, sources such as by-product CO_2 stripped from natural gas or separated in industrial facilities and hence assess the scale of the residual demand of CO_2 for EOR separated from power plant is investigated.

The suitability of oil reservoirs for CO_2 EOR is screened using an established set of criteria (Ahmad and Boujun 2010). Results of the screening will determine whether the CO_2 is immiscible or miscible when injected into the reservoirs. If the CO_2 EOR screening resulted in a miscible process, then it is assumed that the additional cumulative of oil as high as 12% of the original oil in-place (OOIP) can be recovered. But in the immiscible case, the additional recovery is only 5% of the OOIP (Sugihardjo et el. 2012). The ratio between oil recovered and CO_2 injected labeled as performance ratio are assumed to be 3 stock tank barrels (stb) of oil per ton CO_2 injected for miscible process and 2 stb/ton for the immiscible case (Faltinson and Gunter 2013). Knowing the volume of incremental oil to be produced through miscible and immiscible processes, the pore space available for CO_2 can be determined.

III. RESULTS AND DISCUSSION

CCS technology coupled to coal-fired power plants provides a climate change mitigation strategy that potentially permits the continued use of fossil fuels whilst reducing the CO_2 emissions (Hammond and Spargo 2014). This technology has been established for some industrial processes, but it is still a relatively expensive technology. Revenue from selling captured CO_2 for EOR is one option for mitigating the higher upfront costs in CCS. Below describes the potential of CO_2 EOR lowering the cost of electricity generated by coal-fired power plant with CCS.

A. LCOE without CCS

The existing and proposed power plants in RUPT 2013-2022 were screened according to the criteria designed above for their suitability incorporating CCS (Masaki 2015). The most suitable candidates under the criteria are a few coal-fired supercritical or ultra-supercritical coal power plants to be constructed in the timeframe of 2018-2022. As the basis of this study, a proposed coal-fired power plant located in South Sumatera has been selected. The plant that is considered as CO_2 capture-ready will have a power output of 600MW with a capacity factor of 80%. It will use lower-sulphur lignite with high moisture content. The plant is assumed to be commissioned in 2022 with a design life of 25 years. A summary of key parameters of the selected coal-fired power plant is provided in Table 2 (Masaki 2015).

Based on the above assumptions, the LCOE without CCS is estimated at 6.4 cents/kWh, which includes capital costs of 3.9 cents/kWh, cost for fuel 2.1 cents/kWh, and O&M costs of 0.4 cent/kWh. It considered less than the average cost of existing coal power generation (PLN Statistics 2013), primarily driven by the lower cost of coal at the mine mouth. The CO_2 emissions are generated by boilers burning coal and typically discharged through large exhaust stacks. The raw flue gas outlet conditions from the boiler in the host power plant are listed in Table 3. Given the flue gas condition in Table 3, the CO_2 emissions generated by the plant are estimated to be around 4.1 million tonnes (Mt) of CO_2 per year.

B. Incremental Costs of CCS

A monoethanolamine (MEA) solvent-based CO_2 absorption system for post-combustion flue gas applications has been selected considering the flow rates, pressure, temperature, flue gas composition, and CO_2 concentration in the flue gas stream. MEA has proven record in many CO_2 capture situations and is currently in commercial use (Wang et al. 2011). A key feature of amine systems is the large amount of heat required to regenerate the amine solvent. This heat is typically drawn from a Low Pressure (LP) steam turbo-generator and significantly reduces the net efficiency of the power plant. Before being processed in the CO_2 capture system, acid gases such as NO_2 and SO_2 must be removed from the discharged flue gas as they affect the performance of the system by forming heat stable salts with MEA solvent. Environmental air quality legislation in Indonesia requires very low concentrations on the discharge of nitrogen oxide (NO_x) and sodium oxide (SO_x).

As described above, the CO_2 capture system requires additional investments for the CO_2 capture equipment comprising: Selective Catalytic Reduction (SCR) for NO_x reduction, Flue Gas Desulphurization (FGD) to reduce sodium oxide SO_x content of the flue gas, MEA for CO_2 removal equipped with LP steam turbo-generator for amine solvent regeneration, and Compressor and Dryers

Table 2
Key parameters for the reference coal power plant

Location	South Sumatera
Installed capacity	1 × 600 MW
Technology	Supercritical
Commissioning year	2022
Source of coal	Mine mouth
Capacity factor	80%
Boiler efficiency (HHV)(1)	76.3%
Turbine efficiency	44.0%
Coal quality	
Gross caloric value (HHV)	2,600 kcal/kg (as received)
Total moisture content	Average 54%
Ash content	Average 6.5%
Sulfur content (dry ash fee)	Average 0.86%
Annual CO_2 emissions	4.1 $MtCO_2$
Desulfurization technology	None
Power plant efficiency	$40.8\%_{olhv}$ (1)
	$34.4\%_{ohhv}$

Notes: (1) HHV or hhv denotes Higher Heating Value, which also known as Gross Caloric Value, and is measure of heat of combustion for fuels. "lhv" denotes Lower Heating value, which is also known as Net Calorific Value.

(C&D) for conditioning of CO_2 in order to comply with the CO_2 pipeline specifications (Masaki 2015). Among CO_2 capture equipment, the most expensive item is the MEA scrubber, which is the main process for separating CO_2 from the coal power plant flue gas. The four major facilities need about three hectares of additional space.

The incremental costs of CCS are evaluated based on separation of 90%, 45%, and 22.5% of CO_2 capture, respectively. CO_2 capture is an energy-consuming process. The additional energy consumed for capturing CO_2 will reduce the net output of the power plant. The corresponding CO_2 emissions, energy penalty, additional Capital Expenditures (CAPEX) and Operating Expenditures (OPEX) under each capture scenario are listed Table 4. Under the 90% capture scenario, the MEA scrubber accounts for more than half of the incremental investments.

For the purpose of transport and CO_2 EOR costs assessment, eight oil fields in the southeast quadrant of the South Sumatera basin have been identified as having the overall EOR demand to match more than half of the supply from the selected South Sumatera power plant. Distribution pipes to those oil fields would have a combined length of less than about 50 km and an average of 20 inches. The corresponding investments for CO_2 transmission, distribution, and CO_2 EOR are also included in Table 4.

Table 3
Flue gas design basis
in the selected coal power plant

Mass flow rate (tonnes / hour)	2857
Temperature (°C)	152
Pressure (bar)	1.1
H_2O (%)	25.28
N_2 (%)	60.31
CO_2 (%)	12.87
O_2 (%)	1.45
SO_2 (ppm dry basis)	792
NO_2 (ppm dry basis)	<365

Table 4
Power plant output and additional costs of CCS in each scenario

Capture fraction scenario, %	90	45	22.5
Power plant output			
Annual emission, Mt CO_2	0.4	2.3	3.2
Annual CCS, Mt CO_2	3.7	1.8	0.9
Electricity output, MWe	415	508	564
Energy penalty, %	31	15	6
Additional costs			
Total CAPEX, US$ million	743	490	357
Pass out turbine	40	30	30
SCR	56	56	56
FGD	128	98	79
MEA scrubber	425	248	159
C&D	94	58	43
Annual OPEX, US$ million	65	53	40
Investments for CO_2 transportation, US$ million, 2022 dollar	59	36	24
Investments for CO_2 EOR, US$ million, 2022 dollar	37	18	11

The impact of CCS on LCOE is dependent on capture fraction. The higher the capture percentage, the more energy consumed, thus the higher the incremental cost of CO_2 capture on LCOE. Under a 90% capture scenario, the energy penalty comprises more than half the CO_2 capture-related incremental costs. Figure 1 provides a summary of the breakdown of incremental LCOE resulting from different CO_2 capture fractions scenario at the selected power plant.

C. LCOE Comparison

This section discusses how the reference coal-fired power plant with CCS competes against other low carbon technologies in terms of their level of emissions and LCOE. Under the 90% capture scenario, the CCS coupled with the reference coal power plant will increase more than double the cost of supply from the plant, raising the LCOE from 6.4 US cents/kWh to 15.5 US cents/kWh primarily attributed to the energy penalty. Reducing the CO_2 capture percentage from 90% to 45% could reduce the LCOE with CCS from 15.5 to 11.2 US cents/kWh. However, the lower level of capture leads to the expense of higher CO_2 emissions. Figure 2 reveals the LCOE of coal-fired power plant without and with CCS. Also included in the figure are the LCOE of geothermal-based and Combined Cycle gas Turbine (CCGT) power plants.

In terms of CO_2 emissions and availability of power output, a coal-fired power plant with 90% capture is comparable to a geothermal-based power plant. Referring to the Ministry of Energy and Mineral Resource's Regulation 17/2014, the ceiling price for geothermal in Java and Sumatra commissioned in the year 2022 is set at 14.6 US cents per kWh, which is comparable to the LCOE of the reference coal power plant with 90% capture implementation, which is 15.5 cents/kWh. As shown in Figure 2, the reference coal power plant with CCS at 45% capture is comparable to the LCOE of CCGT in 2013. In terms of CO_2 emissions, the case of 45% capture is also comparable to CCGT operating at base load (Masaki 2015).

D. CO_2 EOR as Cost-Offsetting Mechanism

Within the South Sumatera Basin, mature oil fields exist with the potential to recover additional oil

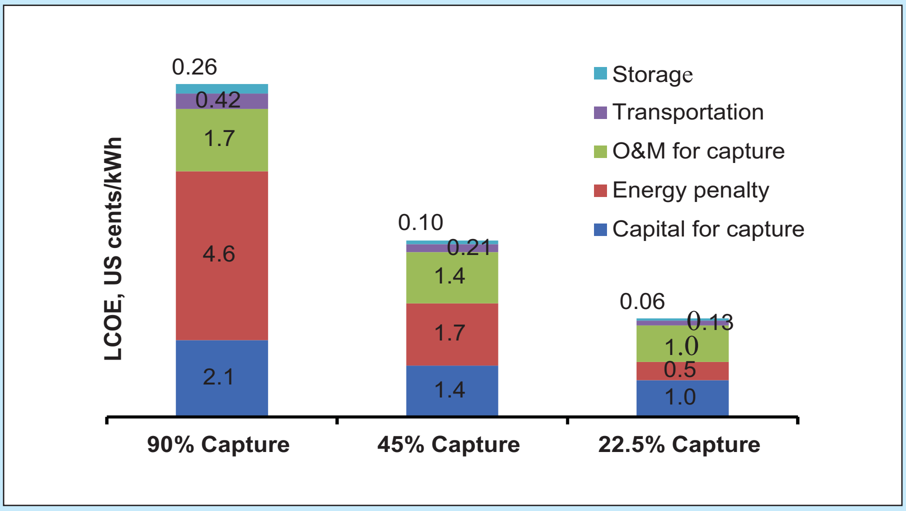

Figure 1
Incremental costs of CCS on LCOE.

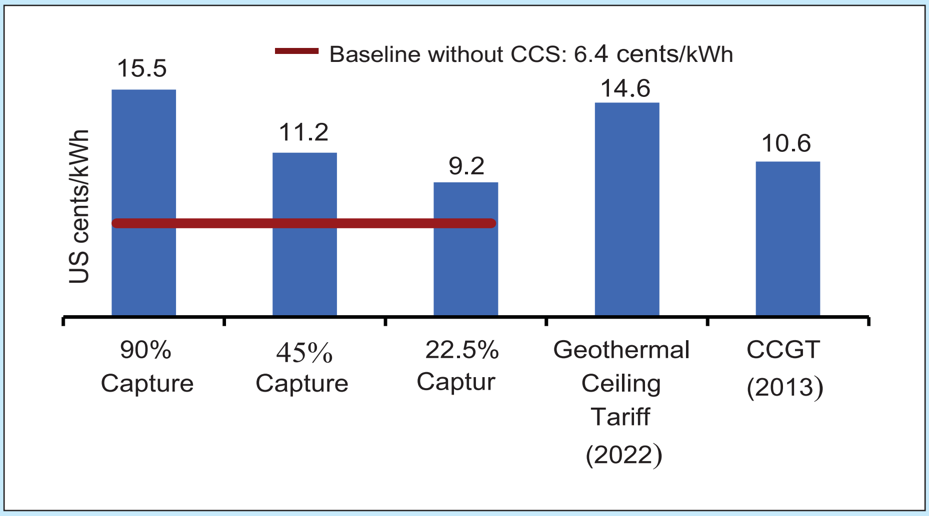

Figure 2
LCOE comparison of coal CCS power plant with geothermal and CCGT.

and store CO_2 through CO_2 EOR application (Usman, et al., 2014). A total of 127 oil fields as potential sites to use CO_2 for EOR in South Sumatera, as shown in Figure 3, are assessed. Of all the oil fields, 96 oil fields are classified as miscible displacement and the remaining as 31 immiscible processes. EOR reservoir screenings are performed on the 52 oil fields that have detailed information. Of the remaining 75 fields that have incomplete information, the miscibility is estimated using depth data assuming that oil fields deeper than 1 km are categorized as miscible while those shallower than 1 km are categorized as immiscible. The pressures of the 75 fields where only depth is known are inferred from the pressure gradient of the 52 fields which have complete data.

Experience indicates that the volume of CO_2 needed for a CO_2 EOR project changes over a field's life. Initially the reservoir is flooded with significant amounts of CO_2 and it may take time before the effect of the injected CO_2 on oil production is seen.

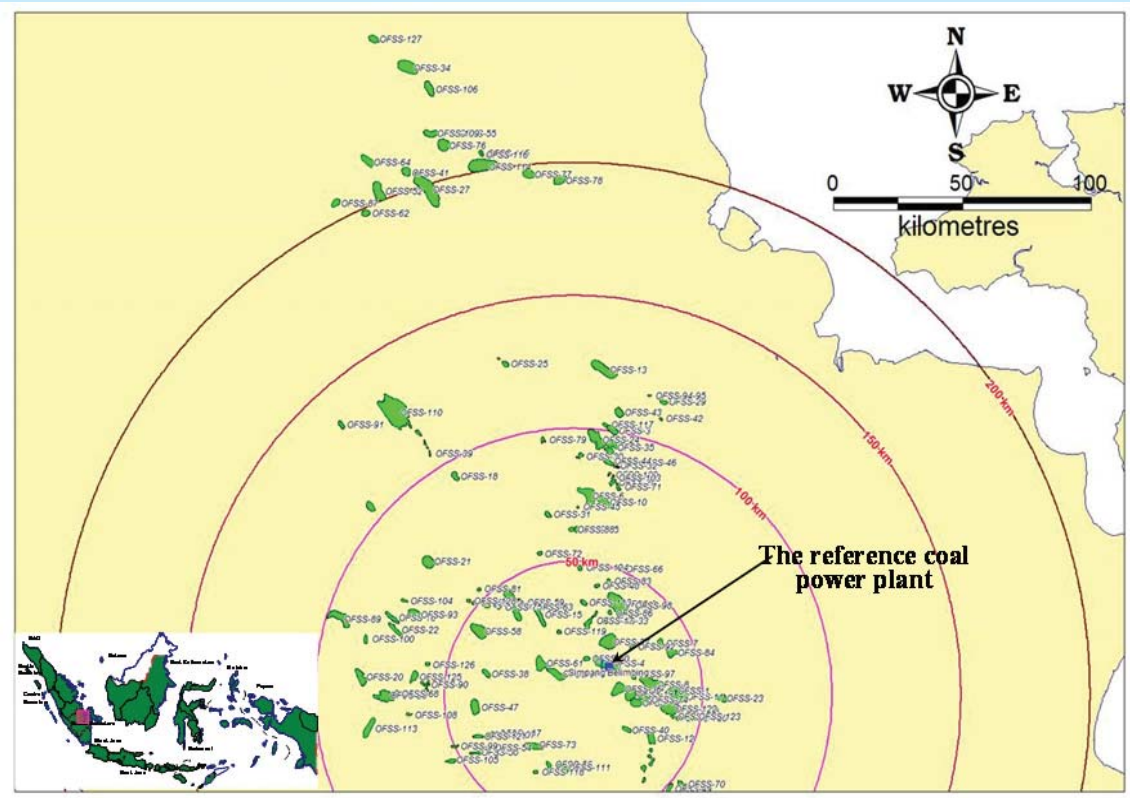

Figure 3
Oil fields location relative to the reference coal power plant.

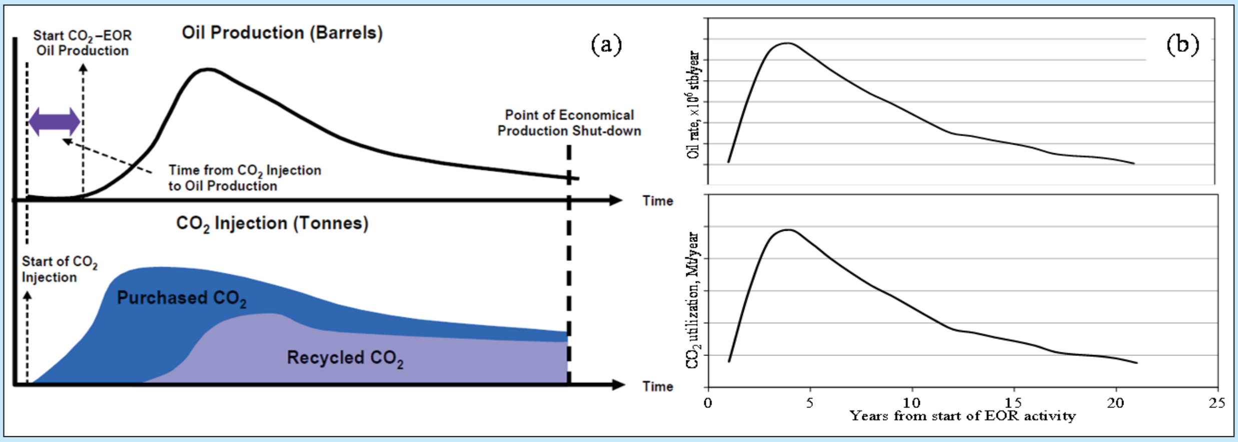

Figure 4
Profiles for CO_2 injection and oil production:
(a) Typical CO_2 EOR project; (b) Studied CO_2 EOR case.

After a period of CO_2 injection, the produced oil will contain CO_2. The CO_2 in this oil is separated and thereafter re-injected back into the reservoir. The result is that the field's need to purchase fresh CO_2 is gradually reduced as more and more of the CO_2 injected is actually produced with the oil itself. This is illustrated schematically in Figure 4(a) for a typical project (ARII, 2011). The CO_2 demand profile with associated oil production for CO_2 EOR application on 127 oil fields assessed in in this study is shown in Figure 4(b). Applying this scenario to the 127 oil fields could recover approximately additional 661 million standard barrels of oil and the CO_2 demand accounting for around 243 Mt over 25 years of CO_2 EOR operation.

The supply of pure CO_2 for EOR in the studied area 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-based power plant flue gas. In contrast to power plant flue gases that contain 10-20% CO_2 and require costly and energy intensive separation, the two first sources would only require compression and transport to be ready to use in CO_2 EOR applications. The availability of these low-cost, ready-to-use sources of CO_2 that in total is likely to amount to 6 $MtCO_2$/year impact on the EOR demand for high-cost CO_2 captured from coal-fired power plant flue gases. An estimated 162 Mt of the demand for CO_2 will likely be absorbed by product from low cost CO_2 sources. The remaining demand of 81 $MtCO_2$ is to absorb the CO_2 captured from the reference power plant.

Revenues earned through CO_2 EOR could offset some of the cost of CO_2 abatement on a captured basis with the CCS. Figure 5 provides an illustration of CO_2 EOR as a cost-offsetting mechanism for CCS. The 90% CO_2 capture resulted in additional cost of 9.1 cents/kWh, raising the LCOE from 6.4 to 15.5 cents/kWh. A a minimal reduction of 0.9 cents/kWh could bring the LCOE down below the ceiling price for geothermal. This is equivalent to CO_2 EOR revenue of US$ 89 million. And similarly for the 45% CO_2 capture case, lowering the cost to 0.6 cents/kWh or more would result in the LCOE being below PLN's average cost of CCGT in 2012. This is equivalent to CO_2 EOR revenue of US$ 60 million. The offset cost on both cases could be gained by selling the captured CO_2 under US$ 10/t at the gate of the plant.

The upside offered by CO_2 EOR to a coal-fired power plant with a CCS project is subjected to further uncertainties. Oil field operators will only be willing to purchase CO_2 when the oil market price can justify the incremental cost of the CO_2 EOR operation. Thus, the volatility of the oil price will be one of the key uncertainties on the upside that CO_2 EOR may provide. The actual quantity of CO_2 transported through a pipeline for EOR may experience considerable fluctuations due to uncertainties of demand within a competitive CO_2 market, leading to the risk of the pipeline becoming a stranded asset. In addition, the nature of power plant operations is that it follows electricity demand. EOR operators may be reluctant to enter into contracts for CO_2 supplies on an interruptible basis.

IV. CONCLUSIONS

The potential of CO_2 EOR to offset the cost of CCS at a coal-fired power plant has been described. A proposed coal power plant in RUPL 2013-2022 is selected as the basis of this study. The LCOE of this plant without CCS is estimated at 6.4 cents/kWh and emits around 4.1 $MtCO_2$/year. Integrating CCS to the reference coal power plant imposed additional costs associated with CO_2 capture, transportation, and storage systems. The incremental costs are evaluated based on separation of 90%, 45%, and 22.5% of CO_2 from the power plant flue gas using an amine scrubbing process, supported by flue gas

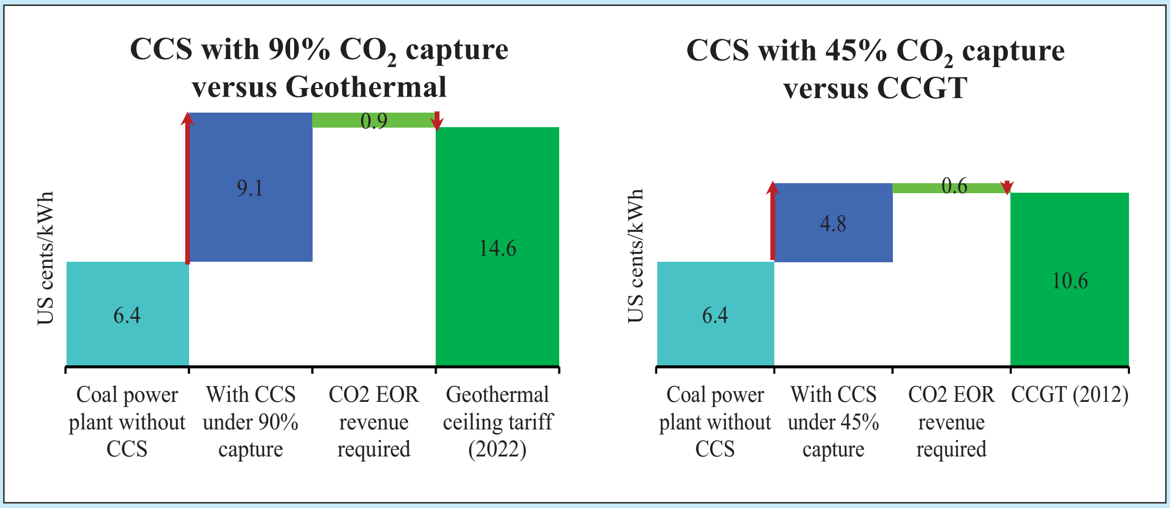

Figure 5
The cost offsetting effect of CO_2 EOR.

cleaning processes, and liquefaction of the captured CO_2 for transportation to oil fields for EOR. Under the 90% capture scenario, the cost of supply from the plant raised the LCOE more than double from 6.4 US cents/kWh to 15.5 US cents/kWh primarily attributed to the energy penalty. Reducing the CO_2 capture percentage from 90% to 45% could reduce the LCOE from 15.5 to 11.2 US cents/kWh. However, the lower level of capture leads to the higher CO_2 emissions.

Selling captured CO_2 for EOR is examined to demonstrate the potential of CO_2 EOR to defray the cost of CCS at a power plant. A total of 127 oil fields identified suitable sites to use captured CO_2 in South Sumatera and have the potential to produce 661 million standard barrels of additional oil. Total CO_2 demand of 243 Mt over 25 years of CO_2 EOR operation would be sufficient to adsorb the CO_2 captured from the power plant, as well as low cost CO_2 sources in this region. Under 90% CO_2 capture scenario resulted in additional cost of 9.1 cents/kWh, raising the LCOE from 6.4 to 15.5 cents/kWh. A minimal reduction of 0.9 cents/kWh could bring the LCOE down below the ceiling price for geothermal. And similarly for the 45% CO_2 capture case, lowering the cost to 0.6 cents/kWh or more would result in the LCOE below PLN's average cost of CCGT in 2012. Offsetting costs on both cases could be gained by selling the captured CO_2 under US$ 10/t at the gate of the plant.

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