ON GOING COALBED METHANE (CBM) DEVELOPMENT IN THE SOUTH SUMATRA BASIN

by

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I. INTRODUCTION

Coalbed methane (CBM) is going to be an important facet of the nation's energy mix. It is expected to contribute in importance energy back up for the future. CBM is natural gas, a clean-burning energy source that is reservoired in a coal seam. CBM is formed during the coal maturation process and may in a free or adsorbed state in coal seams in adjacent formations. CBM is dominantly methane but lesser concentrations of carbon dioxide and nitrogen, compare to conventional natural gas. However, in most cases, CBM is of sufficient quality for sale directly into natural gas transmission lines with a limited amount of moisture removal.

CBM as natural gas has numerous benefits to include direct selling, well suited as city gas, electricity generation, boiler fuel, transportation fuel, and for many types of chemical industries feed. Beside CBM replaces coal to be greatly reduces the production of acid rain and other forms of air pollution, the development of CBM has benefitial for coal miners. It can contribute to improved mining safety as well as it can help reduce construction costs.

CBM is probably one of the promising alternative fuel energy resources in Indonesia that its presence is actual and comparable with the existing coal resources in any potential basin. Unlike some well in developed countries where commercialization of methane production from coal seam has been developed, coals direct mined in Indonesia seem to be more attractive and preferable technique to supply the consumer demand of energy. This is because coal mines serve direct products, less complicated technology, low exploration risks, easy recovery, relatively low cost but quick yields and already have wide market. Consequently, people have overlooked the existence of consisting huge potential methane gas in coals.

However, petroleum exploration data throughout Indonesia suggest that increasing coal rank occurs rapidly with depth in many basins and that gas kicks are almost common associated with some coal seams below 200 m depth. In addition, world CBM exploration now has shifted towards lower rank settings (i.e, vitrinite reflectance between 0.3% and 0.6% Ro). *In* Indonesia, thick coals generally are found at greater depth, higher in rank and therefore are expected to be more productive (Saghafi and Hadiyanto, 2000).

LEMIGAS is currently conducting a drilling program to study the feasibility of CBM production in South Sumatra. The domain of the work is in the Muaraenim Formation (Upper – Middle Palembang). The coal sequences were deposited during Late Miocene. We believe that a big effort is extremely essential to establish the reserve and economic potential of CBM in South Sumatra to later extent to Indonesia.

II. CBM DEVELOPMENT IN INDONESIA

Government of Indonesia (GOI) wishes to encourage CBM development in Indonesia. Demonstrating the encouragement, GOI has initiated the first pilot project for CBM exploration in Indonesia to establish CBM as a clean, environmentally safe energy source that can be developed primarily to fulfill domestic markets. The project is just started three years ago, although some CBM studies has started a decade ago (Nugroho and Arsegianto, 1993).

None of the previous works has been exclusively established the important aspects of CBM such as exploration and development, economic potential and even its utilization in Indonesia. The most ambitious CBM study in Indonesia was carried out by PT. Caltex Pacific Indonesia (PT. Chevron Pacific Indonesia) and was planned to establish the potential CBM in the South Sumatra Basin. Collaboration with Pertamina, The Directorate of Coal and Advanced Resources International, Inc. (ARI), a 4-years evaluation study started in year 1998, has provided a new look of CBM prospect in Indonesia. Starting in the same year, another CBM study was also conducted by a group under cooperation of Directorate General of Oil and Gas, Ministry of Mines and Energy (currently as Ministry of Energy and Mineral Resources). The studies were aimed mainly on the aspects of rules and regulations; and results were of a draft of the presidential decree. Although some efforts have also been made to perform CBM potential in Indonesia, this study however could not be optimized because of the national situation at that time was not conducive and follow up is therefore needed.

Studies outlined above (Stevens et al., 2001; Stevens and Sani, 2002) identified 11 major coal basins with CBM potential in onshore Indonesia. Although remains speculative, they estimate some 337 trillion cubic feet (tcf) of accessible CBM resources in Indonesia which furthermore was based on gross rather than net pay thickness. Recent studies have shown that the CBM potential resources in the 11 major coal basins have been updated to be as much as over 450 tcf (Stevens and Hadiyanto, 2004 and references therin). This is a vast resources, but only a small fraction will likely be recoverable. Among 11 on-shore sedimentary basins in Indonesia defined, the South Sumatra Basin is expected to be the most prospective area for CBM development in the near future due to its magnitude of potential CBM reserve and existing market close to the basin. The potentially completeable CBM in-place resource of around 183 tcf of gas in the basin has estimated (Stevens and Hadiyanto 2004). It is difficult to evaluate the productivity using data directly obtained at present in consideration of no actual pilot test of CBM production. However, it is convenient to think that there is no doubt of possibility to develop CBM in South Sumatra as some researchers has pointed out the basin (e.g: Kurnely et al., 2003; Makino et al. 2006; Sosrowidjojo 2006).

II. SAMPLES AND METHODS

In the past, low rank coals such as Indonesian coal in general would not be a suitable candidate for CBM exploration and production as it was thought that coals of very low rank (lignite and sub-bituminous) could not produce viable volume of methane gas. However in recent years, successful CBM production in some low rank coals, such as the Powder River Basin in USA, has led the CBM industry around the world to explore these coals for gas production as well (e.g. Surat Basin in Australia). It is believed that Indonesian low rank coals could have similar CBM producing potential, since South Sumatra owns the most resources with the amount of 23.2 billion tonnes or as much as 86% of total resources in Sumatra.

The first stage of the study aims at characterizing the coal reservoir for methane production. In order to measure the gas reservoir properties of coal seams of Southern Sumatra, a CBM-1 well test was drilled to a depth of 650 m in the coal measures of the Rambutan Field. The CBM-1 well coring program encountered nearly 40 meters of Late Miocene Muaraenim coal from five separate coal seams, recovering nearly 17 meters of core utilized for this study. These core samples were subsequently sealed in 34 HQ-Type steel canisters, each approximately 55cm in length. All were analyzed for gas content and composition characteristics and nine selected samples were analyzed for detailed gas storage, moisture content, ash yield and maceral group measurements. The highest and the lowest gas content values were deselected to represent the average gas content values.

All coal seams were cored and samples were collected and subjected to geochemical evaluation using standard methods described elsewhere (Saghafi, 2003). Gas content of coals were determined using a quick crush method described elsewhere (Australian Standard AS 3980-1999, 1999). The Q_1 and Q_2 components of gas content were measured in the field and Q_3 components was measured at the LEMIGAS laboratory. The associated gas composition was determined by using the standard gas chromatograph NGA 2261 system. Nine of selected core samples representing four coal seams were used to determine the full storage and flow properties of these coals. The Seam 4 was not selected to further detailed analysed due to lower gas content as well as thiner seam. The gas storage capacity of the coal was measured using the CSIRO method and included analyses of gas adsorption isotherms and coal porosities. The adsorption isotherm of coal is given by the Langmuir Equation where the maximum

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adsorption capacity is represented by the Langmuir Volume (VL) parameter. Methane saturation level for these seams was calculated based on measured isotherms and gas contents. The meso- and macro-porosities (pores larger than 6 nanometers) were measured using the mercury intrusion method, the coal density was measured by the helium injection method and the maceral composition was determined by using a point-counting techniques.

III. GEOLOGY OF THE SOUTH SUMATRA BASIN

The geological setting, stratigraphy and tectonic evolution of the South Sumatra Basin have been described by numerous authors (e.g. Adiwidjaja and de Coster, 1973; de Coster, 1974; Pulunggono et al., 1992; Gafoer and Purbohadiwidjoyo 1986; Daly et al. 1987; Darman and Sidi, 2000). Only a brief summary is presented here.

The South Sumatra Basin (Figure 1) is located to the east of the Barisan mountains and extends into the offshore areas to the northeast and is regarded as a foreland (back-arc) basin bounded by the Barisan mountains to the southwest, and the pre-Tertiary of the Sunda Shelf to the northeast. The South Sumatra Basin was formed during east-west extension at the end of the pre-Tertiary to the beginning of Tertiary times. Orogenic activity during the Late Cretaceous-Eocene cut the basin into four sub-basins. The sedimentary sequences of interest to this study were intersected in the CBM-1 well in the the South Palembang Sub-basin, South Sumatra Basin (Figure 1).

The structural features present in the basin are the result of the three main tectonic events. They are Middle-Mesozoic orogeny, Late Cretaceous-Eocene tectonism and Plio-Pleistocene orogeny. The first two events provided the basement configuration including the formation of half grabens, horsts and fault blocks. The last event, the Plio-Pleistocene orogeny, resulted in formation of the present northwest-southeast structural features and the depression to the northeast.

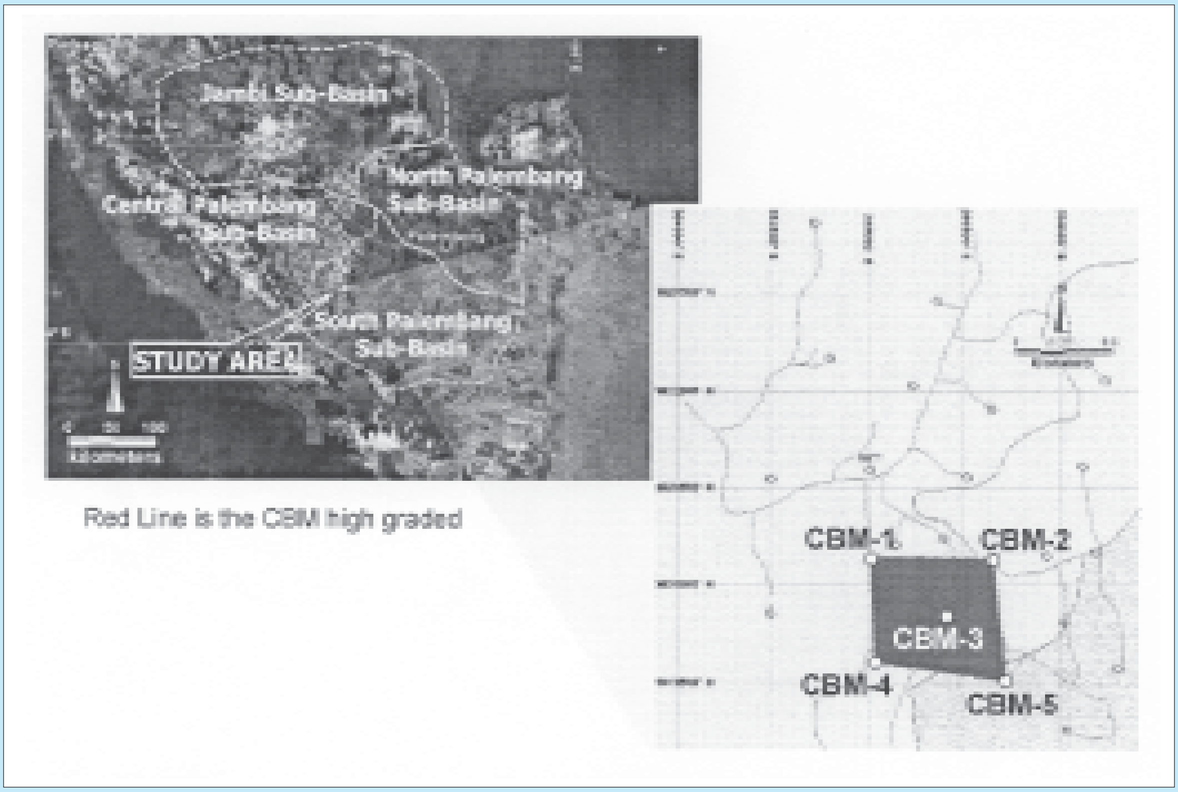

Figure 1
Map showing the study area in Rambutan Field, South Sumatra

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The sediments of the South Sumatra Basin comprise an economic basement of pre-Tertiary rocks that is overlain unconformably by a thick Tertiary sequence. The first Tertiary sedimentation occurred during Early Oligocene and gave rise to the Lahat Formation consisting of mainly volcanic rocks, claystone and shale that was deposited locally in the graben areas. The Talang Akar Formation (Late Oligocene) overlies the basement where the Lahat Formation is missing. It is a transgressive sequence resulting from Late Oligocene to Middle Miocene subsidence. The later sedimentation during mid-Miocene to Recent produced a regressive sequence. The coal seams are part of the Middle Palembang member (de Coster, 1974) of the Late Miocene-Early Pliocene Muaraenim Formation in the South Sumatra

Basin, Indonesia. Boyd and Peacock (1986) reported that the Muaraenim Formation was deposited as a part of a humid tropical deltaic system. In the study area, the seam thickness varies between 2 and 15 m given a total net pay coal up to 60 m. A generalized stratigraphy of the South Sumatra Basin and a summary of the main tectonic events within the basin is shown in Figure 2.

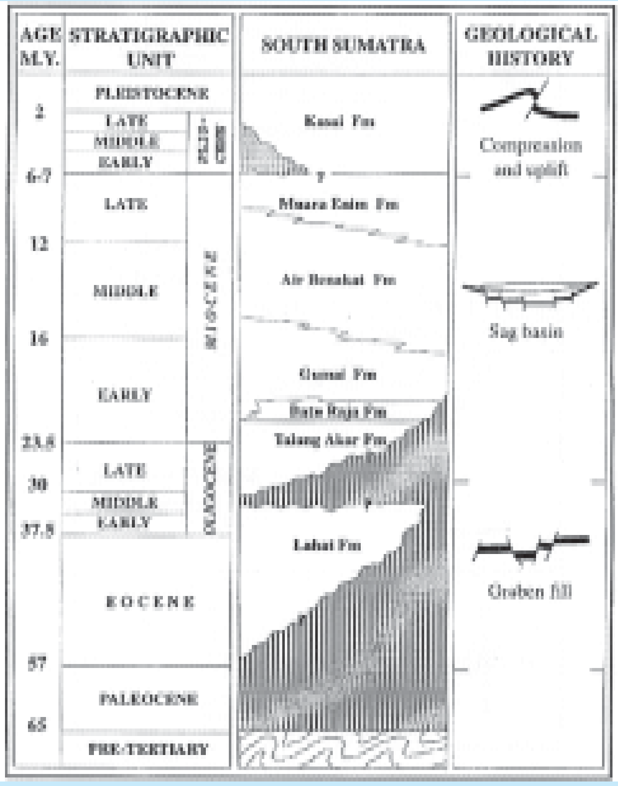

Figure 2
Generalised stratigraphy and geological history of the South Sumatra Basin (Redrawn from de Coster, 1974; Hasan and Soebandrio, 1988)

The economically valuable coal seams crop out mostly in the Tanjung Enim area. In the Air Laya coalfield (southern part of the study area), the coal-bearing strata were subjected to invasion by plug-like masses of basaltic andesite that are presumed to be of Pleistocene to Early Quaternary age (Gafoer and Purbohadiwidjoyo, 1986; Darman and Sidi, 2000). The intrusions caused local thermal metamorphism of the strata and increased the rank of the coals from lignite through to anthracite in some areas.

IV. CBM PILOT TEST

The pilot project plans to drill five wells with tight spacing. A five pilot well is chosen based on the experience of CBM explorations in USA. Because of budget constrain for this pilot project, there is no fund available for accusing working area. So, it is crucial to find a company as a partner to share some acreage for the five pilot well. PT. Medco Energy Eksplorasi & Produksi Indonesia (PT.MEPI) agree to joint in developing CBM within its working area in the Rambutan Field, South Sumatra. They contribute some acreage as well as all geological data in the area.

A seven years project planning has been established (Figure 3) to include G&G Evaluation, Pilot Project, Project Evaluation and Project Development. LEMIGAS fully participates the first two programs and to lesser extent to the following two programs. The later will be carried out by PT. MEPI. The program was started at year 2003 with the primary objectives to find sweet spots. The selected study area was based on the best location available for the study. The area is not ideal for a CBM demonstration pilot, however, any results will lead to promote next pilot project in a better location.

Like oil and gas projects, CBM project is normally phased too, with the drilling of a few pilot wells to test potential production followed by a larger scale development that may reach tens to hundreds of wells. To ensure a commercially viable project, we must have a clear understanding of the regulatory requirements at all stages of project development from the initial identification of a CBM prospect through project planning, drilling, production, abandonment and site restoration.

November 2006, we drilled three pilot wells test for 610m and 1000m total depth with targeting of coal member of the Muaraenim Formation. Typical of 100 ft core of Muaraenim coal have been sampled and properly analyzed for detailed CBM reservoir properties as well as methane gas potential containing in the core samples. Kick was happened went the drilling bit was entering on the Seam 3 of the CBM-2 well, then coring program was cenceled through out of the well due to safety reason. The CBM-5, the third well, was just finished to drill. It was therefore, representative samples were collected from the CBM-1 only.

V. COALBED GAS CONTENT

Table-1 displays the gas content profiles for the five coal seam units sampled. Tables-2 and 3 show the results of more detailed analysis of nine selected samples evaluated to bracket the range of CBM potential of the Muaraenim Formation in the South Sumatra Basin.

The measured gas content of samples studied varied from 0.22 m^3/t for Seam-5 to as high as 5.84 m^3/t for Seam-3, with associated carbon dioxide content ranging from 6% to 27%, and nitrogen and heavier hydrocarbons of less than 1.3%. Seam-3 indicated the maximum gas content of the coals studied at 5.84 m^3/t with an average measured gas content of 3.6 m^3/t. Other seams are less gassy with average measured gas content of less than 1.1 m^3/t. The gas content of the Seam-2 is a litle bit higher than those three seams with average measured gas content of less than 1.61 m^3/t (see Table 1). The gas composition varies with depth as shown in Table 1. The gas composition also varies with depth, and methane composition of the seam gas increases with depth.

Gas in coal occurs in free and adsorbed phases. For low rank coal which contains high pore volumes, a larger amount of free gas can be stored in coal (compared to high rank coal). The free gas is compressed in the available pore volume which is not filled

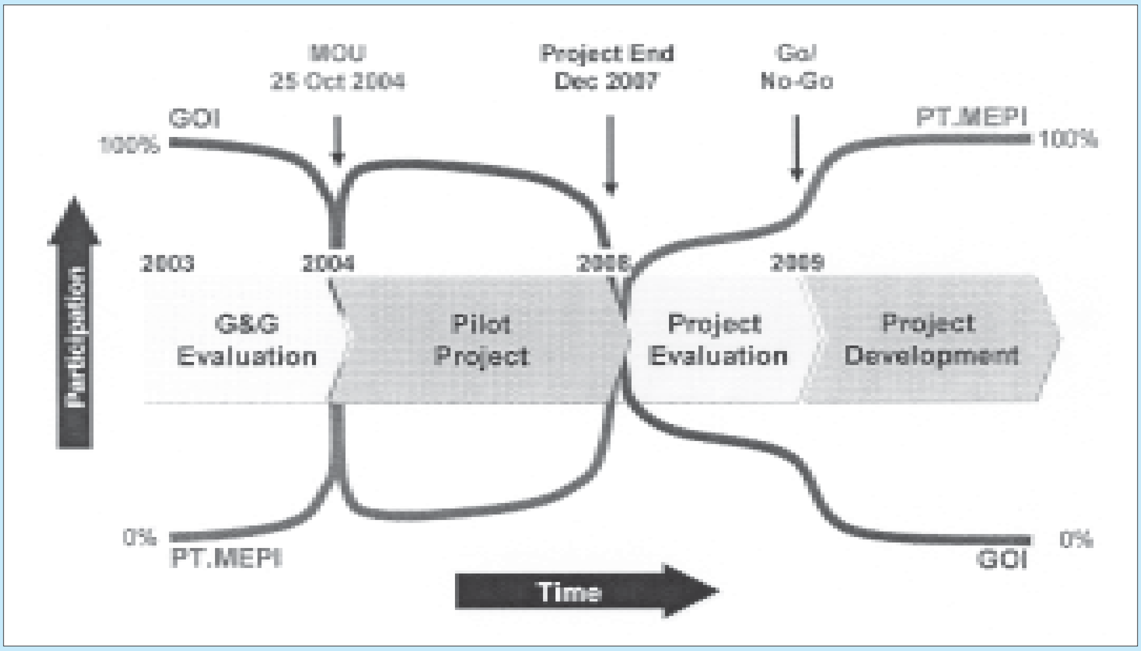

Figure 3
Protocol of CBM development in Rambutan Field, South Sumatra

Table 1
Gas Content and its Composition Data of coal from the first CBM well test

Sample Name		Coal Thickness (m)	Gas Content (m^3/t)			Gas Composition (% min - max)		
ID	# Canst.		Min	Max	Avg.	CH_4	CO_2	$N_2 + C_2+$
Seam 1	3	6.10	0.57	1.24	1.07	71.93-89.60	9.57-26.79	0.83- 1.28
Seam 2	3	9.14	1.35	1.88	1.61	91.56-92.47	6.79 - 7.67	0.74 - 0.78
Seam 3	11	9.14	1.84	5.84	3.60	80.55 - 89.28	10.30-18.82	0.38 - 0.70
Seam 4	6	4.57	0.22	0.83	0.47	76.24 - 88.62	10.45-23.03	0.73- 1.05
Seam 5	11	10.67	0.44	2.94	0.95	80.80 - 93.44	5.77- 18.43	0.72- 1.12

Note: # Canst (# Canister) is canister numbers

Table 2
Coal Proximate and its Petrography Data of coal from the first CBM well test

Sample Name		Coal Density (g/cc)	Proximate Analysis (%)			Maceral group (%)			VR (% Ro)
ID	Canister		Moisture	Ash Yield	Volatile Matter	Vitrinite	Inert	Mineral	
Seam 1	002	1.42	10.20	16.30	35.80	77.70	8.50	8.00	0.290
Seam 2	005	1.31	10.00	5.20	45.80	78.20	8.90	7.90	0.310
Seam 3	016	1.36	10.50	9.00	42.20	77.70	8.00	5.20	0.290
	018	1.33	10.20	7.40	45.20	82.20	6.30	3.80	0.310
	021	1.32	11.40	2.60	42.40	74.10	18.50	2.70	0.300
	024	1.32	11.60	3.50	41.60	78.70	13.50	4.00	0.300
Seam 5	036	1.57	21.40	32.00	22.80	54.60	8.00	32.30	0.310
	042	1.32	24.00	3.60	34.50	83.00	5.30	4.90	0.310
	045	1.49	17.10	23.80	30.60	39.20	29.50	24.90	0.300

Note: Canister 002 (Can-002) refer to canister name for the sample.

with water. Also the pressure driven gas flow depends on the amount of free gas available. The estimated maximum free gas volumes at sample depths are presented in Table 3. It is assumed that equilibrium exists between hydrostatic and gas pressures at sample depth. These values are the maximum capacity and actual values would be lower and can reduce to nil if the coal is water saturated.

VI. GAS STORAGE PROPERTIES

Space of coalbed gas storage reflects the maximum gas volume in the coalbed. In theory, gas volume maximum in the coalbed can be estimated by using adsorption isoterm analysis. The maximum volume for gas within the coalbed ideally should be the difference between maximum space of coalbed and combined volumes ash and moisture contents. So the less ash and moisture contents within coalbed, the higher gas volume can be produce.

The Proximate Analysis of coal samples used in this study is presented in Table-2. In general, the data shows large variations in several components, such as ash yield from 2.6% to 32.0%, moisture content ranging from 10% to 24% and to a lesser degree density which varied from 1.32 g/cm^3 to 1.57 g/cm^3. Coal petrography shows that the samples are vitrinite rich with a mineral-free vitrinite content of 76% to 87% for all coals except the deepest one which has a vitrinite content of 52%. The coals with high vitrinite and low mineral contents typically have favorable reservoir properties for gas storage and methane production. Coals are of low rank with vitrinite reflectance (% Ro) varying from 0.29% to 0.31% suggesting brown coal or lignite.

The adsorption capacity of these coals shows a large variation in Langmuir Volume (VL_1) ranging from 6.3 to 20.1 m^3/ton on a dry ash free basis (daf). Figure 4 show the adsorption capacity data for the nine samples analyzed. The sample (from Seam-1) at the top of the coal sequence shows the highest VL_0 value

Table 3
Porosity, Permeability and Langmuir Adsorption Data of coal from the first CBM well test

Sample Name		Porosity (%)	Permeability (mD)	Max Free Gas Content (m^3/t)	Methane Saturation (%)
ID	Canister				
Seam 1	002	12.83	4.99	4.30	5.36
Seam 2	005	9.10	5.80	3.59	11.21
Seam 3	016	15.84	9.66	6.24	56.34
	018	14.47	2.82	5.84	56.01
	021	11.07	2.60	4.51	46.47
	024	10.36	2.65	4.24	26.47
Seam 5	036	8.33	3.19	3.19	14.94
	042	12.58	6.55	5.75	22.21
	045	10.96	7.88	4.50	9.84

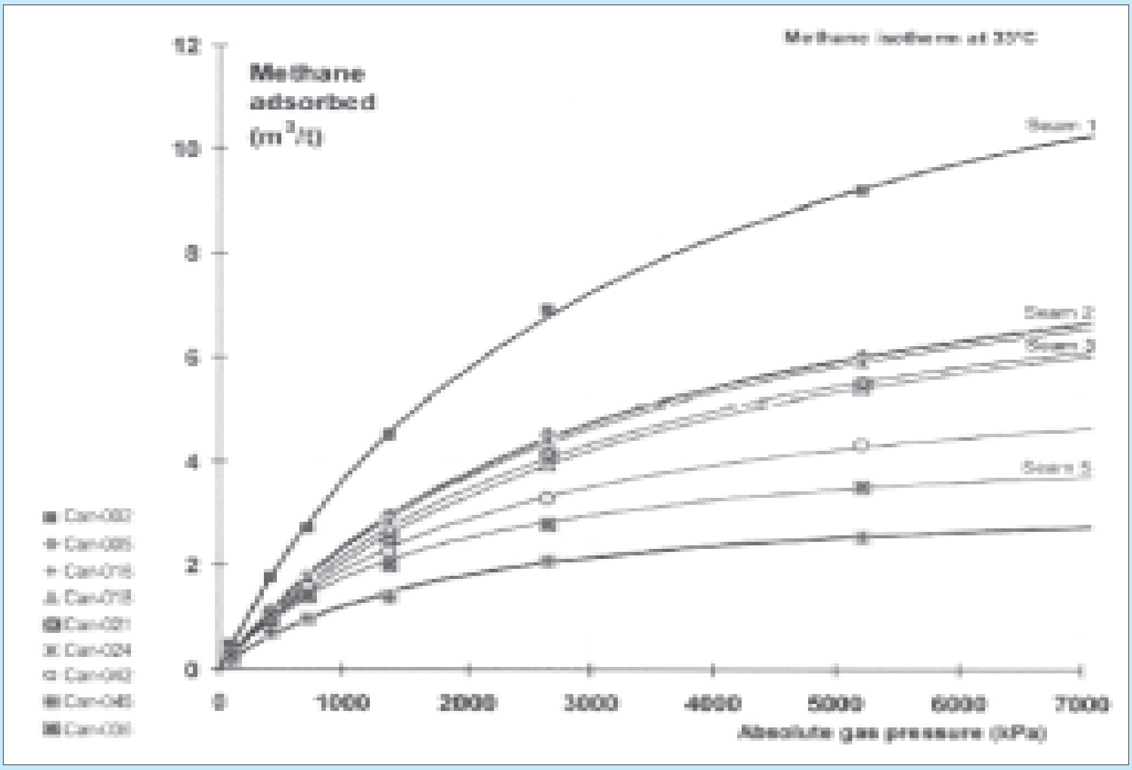

Figure 4
Methane adsorption isotherm of coals from the CBM-1 well test

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of 14.8 m^3/t with a VL_1 value of 20.1 m^3/t (daf). The deepest sample (from Seam-5) showed the least adsorption capacity with a VL_0 of 3.4 m^3/t and a VL_1 of 7.4 m^3/t daf. It should be noted that this sample also had the highest ash yield (32.0%) and the second highest moisture content (21.4%). For the other seams the VL_0 varied between 4.6 and 9.6 m^3/t.

VI. RESERVOIR DEPRESSURIZATION FOR CBM PRODUCTION

The measured porosity of the nine coal seams vary from 9.1% to 15.8% with the highest in Seam-3 (see Table 3). Based on the porosity data the potential free gas storage capacity would correspond to coal methane storage capacities of 3.6 m^3/t to 6.2 m^3/t (assuming no formation water exists in the coal). Permeability data (also shown in Table-3) is generally low with values less than 10 mD.

Methane saturation levels determine the onset of gas desorption. High gas saturations are beneficial to gas production as less dewatering is required to lower the downhole pressure for gas release and flow into the wellbore. Based on the isotherm data, and assuming that the hydrostatic pressure equals gas pressure at seam depth, the saturated adsorbed methane content of the coals are estimated (refer to Table 3). Seam-3 has the highest saturation level with a value of more than 56%. The other coal seams are lower in methane saturation generally below 20%. Seam 1, which has the highest methane capacity (saturated content of 8.6 m^3/t), has the lowest saturation (~5%). For methane production therefore Seam 3 would reach the desorption pressure rapidly and could liberate higher volumes of methane compared to other seams because of its higher gas content. Hence, they will have less productivity until they have been dewatered more extensively.

As all the coal seams are under saturated in adsorbed methane (Table 3), the reservoir pressure has to be drawn down to allow the onset of gas desorption and flow into the CBM production well. Depressurization of the coal seam reservoir is obtained by pumping ground water out of the well. For example, assuming that Seam 3 is the target of coal seam methane production and based on measurements undertaken in the course of this study, the pressure drop required to allow gas desorption can be estimated. The gauge pressure rather than absolute pressure was used so that the gas volumes would correspond to the desorbable gas contents. As is seen in Figure 5, the downhole gas pressure is 5600 kPa, assuming there is hydrostatic equilibrium. This pressure should be reduced to about 2400 kPa for methane to start to release from coal. This requires a seam depressurization of about 3.2 MPa.

VII. CONCLUSIONS

The first CBM demonstration project, that is fully funded by GOI, is progressing in Indonesia with two objectives covering R&D and industry. The R&D objective includes increasing the capabilities of national human resources and developing a centre of

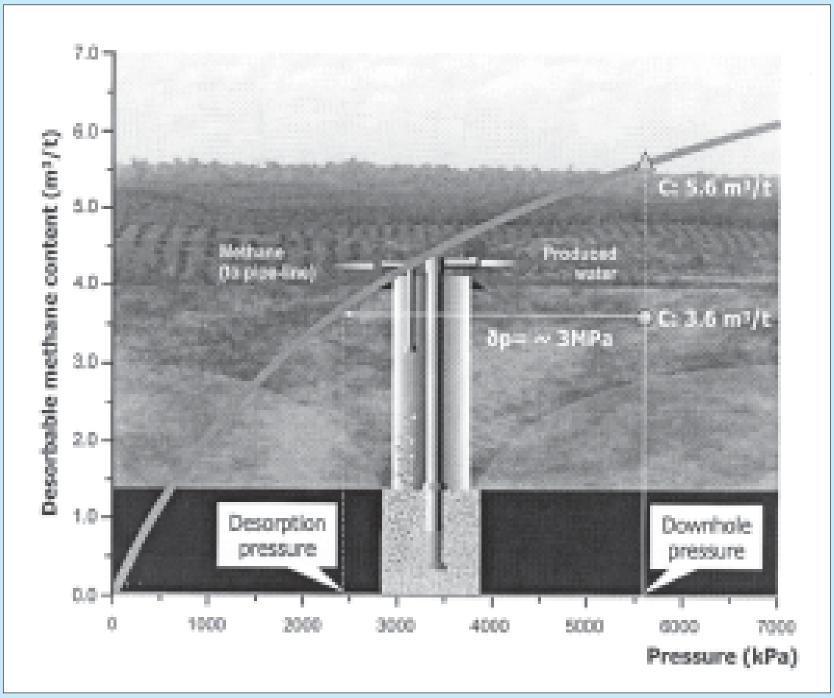

Figure 5
Depressurization of the Seam-3 up to 3.2 MPa to release methane gas

excellence for CBM Development in Indonesia. The industrial objective includes establishing CBM reserve in the location of pilot project, to develop Investment Window throughout CBM database and to initiate CBM exploration in South Sumatra Basin.

The Late Miocene Muaraenim coal deposits have good CBM potential for typical low rank coals, with Seam-3 being the best within the stratigraphic sequence studied. The South Sumatra area has an estimated in-place gas volume of approximately 183 tcf. Preliminary indications, such as coal rank, depth, and cumulative coal thickness information, suggest that CBM exists in the South Sumatra Basin in amounts that should interest the CBM industry which could be a very viable energy resource in the near future for Indonesia.

VIII. ACKNOWLEDGMENTS

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