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Acquah-Andoh, E., Putra, H., Ifelebuegu, A. & Owusu, A.

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Coalbed Methane Development in Indonesia: Design and Economic Analysis of Upstream Petroleum Fiscal Policy

Elijah, ACQUAH-ANDOH[a]

Herdi A. PUTRA[b]

Augustine O. IFELEBUEGU[c]

Andrews, OWUSU[d]

[a] School of Energy, Construction and Environment, Coventry University, Priory Street, CV1 5FB. Email: ab4882@coventry.ac.uk

[b] BKPM – Indonesia Investment Coordinating Board. Email: herdi_ap@yahoo.co.id

[c] School of Energy, Construction and Environment, Coventry University, Priory Street, CV1 5FB. Email: aa5876@coventry.ac.uk

[d] School of Economics, Finance and Accounting, Coventry University, Priory Street, CV1 5FB. Email: ac1980@coventry.ac.uk

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Abstract

Due to increasing demand for natural gas in Indonesia, the Government now promotes exploration for coalbed methane (CBM). Currently, Indonesia has 453 trillion cubic feet (TCF) of CBM reserves. However, CBM development in the country is still in the exploration phase, with significant under-investment. To attract investors, a tailored Production Sharing Contracts (PSC) regime is required. Based on a combination of Factor Analysis (FA), Discounted Cash Flows (DCF) and Parameter Sensitivity Analysis, the research explores an optimal scenario of a company's share of revenue that optimised CBM development contracts. We find that a combination of 5 years straight line depreciation (SLD), 5% First Tranche Petroleum (FTP), 78% Contractor Share (CS) and 35% income tax best spreads the risk of CBM development and exploitation between the government and the contractor. This combination is a more suitable PSC regime for developing CBM in an early stage of the industry. Therefore, the Government must cede some taxes during exploration to incentivise CBM development. Three PSCs regimes are thus required to fully develop and exploit CBM, including exploration, transitional and exploitation phase PSCs which better match contractor risks and returns and ensure reasonable certainty of contractor cost recovery.

Keywords: coalbed methane , development contracts, Production Sharing Contracts , investments, unconventional, natural gas

1. Introduction

Indonesia suspended its membership of the Organisation of the Petroleum Exporting Countries (OPEC) in 2009 because it was no longer a net exporter of oil (OPEC 2014). The country's oil and gas production have experienced decline in recent years, whilst domestic energy consumption has increased (Dartanto 2013; Statistica 2018). The Directorate General of Oil and Gas (DGOG) reports that energy demand had shifted from oil to gas consumption, noting an average annual growth rate of 9% between 2003 and 2016 (DGOD 2018). Consequntly, the DGOG predicts a gas supply deficit to start from 2019 to 2050.

Relatedly, the US Energy Information Administration [EIA] (2014) noted that the growing population and a strong economy had increased Indonesia's total energy consumption by 44% between 2002 and 2012. In 2015, Indonesia had required 50% of imports to meet its domestic energy demand (Boston Consulting Group 2018) and her demand for oil increased by 1.4% and 4.4% in 2016 and 2017, respectively (British Petroleum [BP] Statistcial Review 2017; 2018). Struggling to find new oil reserves, the country explored other energy sources including natural gas. In fact, Jero Wacik, the Minister of Energy and Mineral Resources of Indonesia, stated in his opening speech of the 36th Indonesian Petroleum Association Conference, that Indonesia's target was not to increase oil liftings but to shift her policy paradigm from oil lifting to energy lifting (Oil and Gas Financial Journal [OGFJ] 2012). Thus, the traditional prolific oil producer would now pursue and exploit a wider array of energy sources because production from mature oil fields are falling whilst domestic demand growth has necessitated the importation of a large percentage of its domestic energy.

The desire to step up production has spurred government's interest to promote the development of unconventional hydrocarbon resources, such as coalbed methane (CBM), a primary coal seam gas collected from unmined coal seams in Indonesia. By 2016, 60 unconventional natural gas development contracts had been signed; 54 CBM and 6 shale gas (SG) blocks, yet these projects according to The Ministry of Energy and Mineral Resources (MEMR), have been stagnant due to lack of operator commitment (The Insider 2018). In late 2016, 10 SG and CBM licenses were lined up to be relinquished to government (PriceWaterhouseCoopers [PWC] 2018). In 2017, The Government of Indonesia auctioned oil and gas blocks but failed to attract investors for the unconventional blocks (The Insider 2018). The Government again opened competitive bidding for two unconventional blocks in its South Sumatra Basin, projecting that production in this basin alone could reach 1.14 trillion cubic feet (TCF) of CBM, 75.44 million barrels of oil (Mmbls) and 10.88 TCF of shale gas (ibid).The MEMR estimates Indonesia's CBM reserves to be around 453 TCF, making the country the 6th largest reserves holder in the world, with SG reserves of about 574 TCF (PWC 2018). This is potentially four times the current estimate of 101.40 proved conventional gas reserves in Indonesia (PWC 2018). In particular, the country's major coal-seam basins and reserves are distributed as follows: 183 TCF in the South Sumatra Basin (Mujiyanto and Tiess 2013), 101.6 TCF in the Barito Basin and 80.4 TCF in the Kutai Basin (Thomas 2013).

Despite these bright prospects for CBM development, no significant strides have been made towards exploiting the resources with activities still largely in the exploration and appraisal phases (Thomas 2013; PWC 2018; The Insider 2018). Nevertheless, the resource has the potential to attract investment from renowned oil and gas operators. In fact, Indonesia-Investments (2014) records that the first significant project in Indonesia was the Sanga Sanga field in East Kalimantan, which was awarded in 2009 to a consortium in which BP plc and the Italian oil and gas company Eni hold large stakes. This show of interest was however after a policy response by the government to actively promote the development of the resource among potential operators.

In an attempt by the Indonesian Government to attract investors, legislation was passed in 2007 to support the Government's programme to stimulate the development of unconventional resources (Indonesia-investments 2014). Specifically, this Act of Parliament suggests that contracts for CBM projects shall be based on Production Sharing Contracts (PSC). Consequently, MedcoEnergi was awarded the right to commercially develop CBM with a PSC profit gas split of 45% company share and 55% of government share (International Energy Agency 2008). The company's share of profit in CBM PSC is higher than it is for conventional oil or gas development contracts, which stand at 15% and 30%, respectively (Indonesia-Investments 2014).

In 2017, the Government also amended its regulation on cost recovery and income tax for upstream oil and gas operations, Government Regulation [GR] 79 of 2010, replacing it with GR 27 (PWC 2018; Deloitte 2017). GR 27 came into effect on June 2017 and was intended to stimulate investment and encourage more oil and gas exploration via a more lenient tax regime and 'accelerated' cost recovery framework. However, even with these interventions, CBM development contracts still appear unattractive to the industry, with a serious concern of the lack of industry interest in the development of CBM.

Given that CBM is in its infancy and the urgent requirement for investment in the resource, what should be the focus of government policy to exploit the resource? To what extent does the split percentage for CBM PSCs appeal to potential CBM operators and attract investment into Indonesia for the development of CBM reserves, given that the development costs for this resource are much higher than conventional gas or oil resources (Le 2018; Hanania *et al*. 2019; Aguilera 2014; Seidle 2011)?. Further, given the range of uncertainties in the oil and gas industry and markets, to what extent does production cost, capital expenditure and market factors such as gas price volatility affect the viability of CBM development in Indonesia?

Although these are fundamental questions which require answers to optimally develop Indonesia's CBM reserves, little attention has been paid by researchers to provide better understanding of the current Indonesian CBM development. For example, Stevens and Hadiyanto's (2004) work which is currently the most complete review of CBM in Indonesia, and has been used as references for many Indonesian CBM research, undoubtedly fails to account for the current state of CBM development. Nugroho and Arsegianto (1993) did an economic evaluation of CBM development in Jatibarang Field, but like the work of Stevens and Hadiyanto, this research has limited relevance to the current discussions on CBM in many aspects. In particular, questions arise on the currency of Nugroho and Arsegianto's research today and whether or not their conclusions are still relevant for the CBM industry. It is now an apparent requirement to update the research on the economics of CBM in Indonesia to influence government policy. The present research updates the literature on the economics of Indonesia's CBM and more generally, unconventional natural gas development. According to Craig McMahon, the Head of Asia Upstream Research of Wood Mackenzie (2013), Indonesia has enormous potential for CBM, but to unlock this, the fiscal environment needs to provide greater incentives and operational flexibility to investors. In this study, an optimal PSC regime that better supports Government's objective to attract investment to develop CBM in Indonesia is explored. The analysis particularly focuses on the effects of gas price, production rates, costs, optimal profit gas split, government taxes and depreciation on contractor and government cash flows to offer a rendition of an optimal PSC for CBM development.

The rest of the study is structured as follows. Section 2 reviews the literature in relation to CBM reserves in Indonesia, production mechanisms and cost factors and a brief history of Indonesian PSC regime. Section 3 discusses the data sources and method of analysis. Section 4 presents the results and discussion, whilst section 5 provides conclusion.

2. Indonesia's CBM Resources and Upstream Petroleum Fiscal Framework

2.1 CBM Reserves in Indonesia

Research on CBM in Indonesia dates back to the early 1990s. Nugroho and Arsegianto (1993) did an economic analysis of CBM development in the Jatibarang Field and estimated that Indonesia had 213 TCF of CBM reserves, spread over 16 basins. The authors further noted that Jatibarang Field, located in West Java, is the best prospective area because of its established facilities and infrastructure, and the high demand for gas around the area. It is important to note that no CBM project had been developed at the time of their research. As an improvement, Kurnely *et al*. (2003) did a preliminary study of CBM development in the South Sumatra basin and estimated Indonesia's reserves to be around 337 TCF, spread over 11 basins. The most recent study is by Stevens and Hadiyanto (2004) who argue that there are estimated 11 onshore coal basins in Indonesia with the total prospective CBM resources of 453.3 TCF. **Figure 1** shows the location of Indonesia's major coal basins.

Figure 1: Location of Indonesia's Coal Basins (Stevens and Hadiyanto 2004)

This CBM estimate is the official estimate of Indonesia's CBM reserves in most documents and it is accepted by the Government of Indonesia as the official CBM reserves (PWC 2018). However, the above studies failed to propose relevant policies to help the Indonesian Government to attract investment and develop CBM reserves. Addressing these limitations is the focus of this current study.

2.2 Production Mechanisms and Cost Factors

Critical development factors of CBM are favourable geology; thick gas-rich coal seams at shallow depths with good fracturing, low ash content saturation and permeability; favourable gas markets and price; low capital and operating expenses as well as a favourable fiscal environment (World Energy Council 2016; World Petroleum Council 2008). To extract CBM from a coal seam reservoir, the reservoir itself needs to be engineered so that the gas could flow from the reservoir to the borehole and CBM is absorbed on the surface of the coal. The water contained in the coal fractures will hold the gas in the matrix of the coal. This process is very different from a conventional gas reservoir, where the gas is compressed into the pore space of the reservoir rock and as the pressure goes down, it will easily flow gas to a wellbore (Seidle 2011). This condition makes CBM an unconventional natural gas resource and very much more expensive to develop than conventional gas. In particular, CBM development uses a different method to extract the gas from the reservoir, or in this case, the coal seam relative to the different characteristics of a conventional hydrocarbon reservoir. To develop the unconventional gas resource, CBM projects will require the dewatering process of coalbeds which result in the production of gas at the surface (CBM Asia 2012).

Moore (2012) states that the time required for dewatering is highly dependent on a combination of factors, viz, percent gas saturation and degree of permeability, and important mechanical conditions, requiring that, for example the pump size and quality of performance are equal. Kurnely *et al*. (2003) in their study on CBM development in South Sumatra basin noted that the dewatering stage is about 3 – 5 years depending on the coal characteristics and its environment before the stable production stage. Typically, CBM projects cover large areas of land with producers drilling hundreds of wells; effectively making the resource very expensive to monetise. Horizontal drilling is used to reduce the impact of land access issues (CBM Asia 2012). CBM Asia (2012) has produced a document on the five phases of the development of CBM projects as well as some cost issues associated with CBM projects. In particular, the critical determinants of the economics of CBM projects include coal basin characteristics, gas price, infrastructure availability, competition from production of conventional gas, waste water disposal options, and ease access to gas markets, among others (Chakhmakhchev 2007; Nugroho and Arsegianto 1993 and Kurnely *et al*. 2003). By combining a range of these widely acceptable CBM development causers, we include an economic analysis of the effects of fiscal features, especially incentive regime, on the attractiveness of the CBM PSC regime.

2.3 Current Indonesian PSC Regime

Oil and gas development in Indonesia is performed based on the PSC regime. The purpose of this fiscal system was to maximise the Government's Take [GT] (i.e. Government share of oil and gas cash flows, after allowable capital and operating costs) of hydrocarbon revenues and control the resource at the same time, whilst protecting the state purse from exploration risks (PWC 2018). Consequently, the foundation of the PSC regime is based on law, The Indonesian Basic Law 1945 Article 33, which states that all natural resources are controlled by Government and will be used for prosperity of the people (Ferdian *et al*. 2014; PWC 2018).

From 1966, the Government of Indonesia (GOI) has demonstrated commitment to achieving a balance in its fiscal regime to attract investment. The PSC regime in Indonesia has consequently evolved three times since 1966 to its current form. Table 1 presents a summary of the differences between each PSC typology.

INSERT TABLE 1 HERE

As Table 1 demonstrates, Indonesia has gone through three main PSC generations, but that the three fiscal elements of its PSCs are fairly constant since 1966, with First Tranche Petroleum [FTP], Cost Recovery Limit [CRL], Domestic Market Obligation [DMO], Equity Oil/ Gas to be Split [ETS] and Income Tax being the main features of all fiscal regimes. Together, these fiscal elements target oil and gas income for the state and ensure government's broader objectives for the development of hydrocarbons in Indonesia are achieved in accordance with the country's Basic Law of 1945 on petroleum and in line with Oil and Gas Law 22/ 2001 as stated below:

The law regulating oil and gas activities is Law No. 22 dated 23 November 2001 (Law No.22). Its stated objectives (Article 3) are to:

a. Guarantee effective, efficient, highly competitive and sustainable exploration and exploitation;

b. Assure accountable processing, transport, storage and commercial businesses through fair and transparent business competition;

c. Guarantee the efficient and effective supply of oil and gas as a source of energy and to meet domestic needs;

d. Promote national capacity;

e. Increase state income; and

f. Enhance public welfare and prosperity equitably, while maintaining the conservation of the environment (PWC 2017:15).

In April 2016, the DGOG published a 15-year Roadmap (2016-2030) for Indonesia's oil and gas sector and projected that $48.2 billion investment will be required to develop gas infrastructure alone in order to support Government objectives on natural gas development (DGOG 2018). In the light of current realities of upstream oil and gas development in Indonesia, the Government, in 2017 amended its laws on upstream oil and gas, replacing GR 79 of 2010 with GR 27. The general purpose of the amendment is to incentivise the development of oil and gas in order to attract investment into the country. Table 2 summarises some of the relevant features of the new regulation – GR 27. As Table 2 demonstrates, the features of GR 27 cut across state revenues including FTP to tax on uplifts and transfers.

INSERT TABLE 2 HERE

3. Data sources and method of analysis

3.1. Data sources

Estimates of Indonesia's CBM proved reserves, including the characteristics of Indonesia'a main basins and the map of CBM working area, were adapted from Stevens and Hadiyanto's (2004) work and Indonesian DGOG [Dirjen Migas, 2014]. Operating costs and natural gas prices data were collected from McKinsey Indonesia. To fully appreciate the operational envelope that justifies CBM development, the natural gas price was presented in different scenarios. The fiscal terms of the PSC regime for CBM projects in Indonesia were collected from the official website of Dirjen Migas. As Figure 2 demonstrates, CBM Asia (2012) has summarised the terms of CBM PSC in Indonesia and this was used as a reference to perform the analysis. Included in the flowchart are the main PSC features in a CBM contract.

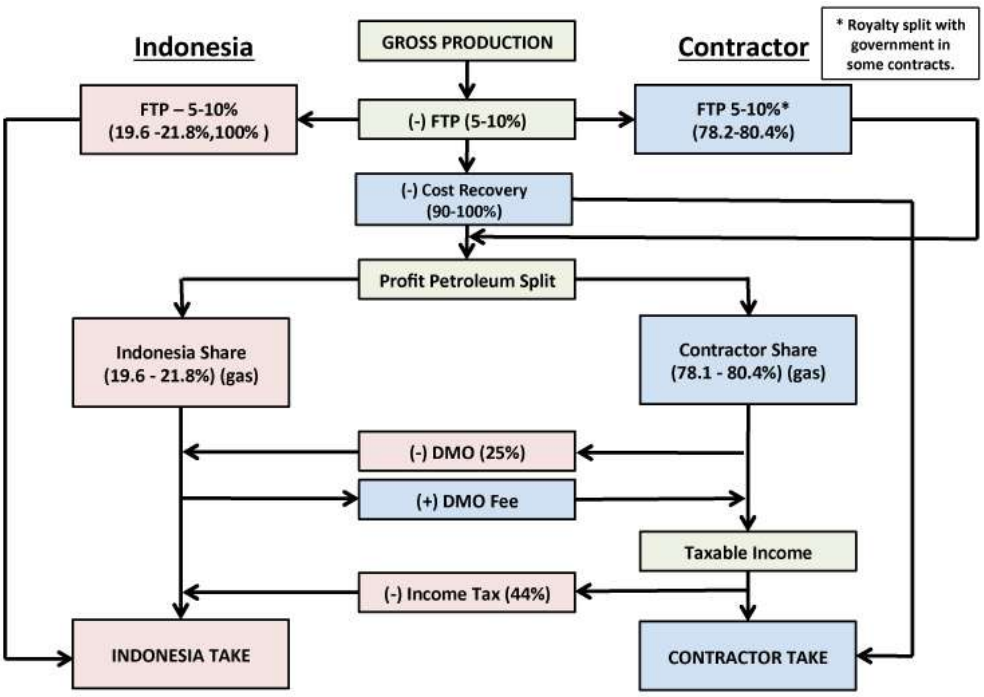


Figure 2: Fiscal Elements of Most Favorable PSC Regime for Indonesia
Source: CBM Asia (2012)

3.2. Method of Analysis

The value of oil and gas projects, and in fact mineral resource investments have been researched widely with the application of technics of varying complexity. Interestingly, the discounted cash flow method (DCF), based on net present value (NPV), internal rate of return (IRR), payback period (PBP), etc., is still widely used by industry for evaluating projects of all scales and complexity. The method also features in oil and gas fiscal studies (MacMillan 2000; Finch *et al*. 2002; Putten and MacMillan 2004; Meehan 2013; Shafiee *et al*. 2019), for its simplicity and ease of understanding and also for the fact that it complements other more complex decision support approaches (Putten and MacMillan 2004).

Also more sophisticated methods such as linear programming, decision trees, life cycle analysis, real options valuations based on beometric brownian motion, mean reverting processes, etc. have been applied to oil and gas investments (MacMillan 2000; Shafiee *et al*. 2019), renewable energy projects (Kim *et al*. 2017; Fernandes 2011; Kozlova 2017) and mineral and metals projects (Zhang *et al*. 2015; Zhang *et* al. 2016; Zhang *et al*. 2017; Haque *et al*. 2014; 2016; Ajak and Topal 2015; Jaimungal *et al*. 2013; Savolainen 2017). Common justification for such application is the volatile nature of prices and costs that determine the value of investments. Indeed real options valuation is a powerful tool to capture the underlying uncertainties of commodity prices and to value the importance of flexibilities in mineral resource operations. The value of oil and gas investments, and in particular unconventional natural gas, is much a function of geology, commodity prices, operating costs but importantly government tax policy too.

Nonetheless, most of these factors are less controllable by the investor or government. For the oil and gas industry, it is common that governments would rather change their tax policies, which they have control over, at times when market, operational and geological factors render the value of investments less attractive to industry or when these factors change in a way that they induce windfalls. Extant research suggests that oil and gas producing countries have reviewed their resource taxes during unfavourable price regimes but increase such during favourable price regimes (see for example, Johnson 2003; Nakhle 2008; Holterud 2011; Stevens 2013; Ivan *et al.* 2015; Wood Mackenzie 2015). In particular, Stevens (2013) find that over thirty-three oil and gas producing countries revised their petroleum fiscal contracts and some of them their entire tax regime between 1999 and 2010, in response to crude oil and natural gas price changes.

The focus of this current research is to extend research on such government interventionist approaches to CBM investments via a review of the petroleum fiscal policy during early development of the resource in order to encourage investments for exploitation of CBM. It has been suggested that resource nationalism is a cyclical event (Clarke and Cummins 2012) and echoed as follows: "…when oil prices decline, companies are enticed to return to states which had sought to discourage private investment" (Ward 2009:33; Nakhle 2016). Governments have thus been seen to interfere with oil and gas tax regimes and this development is of primary interest in this research.

The estimation of the value of natural gas and its attendant uncertainties that result from uncertain commodity prices or geology is beyond the scope of this research. For this reason, DCF approach together with Factor Analysis (FA) and Parameter Sensitivity Analysis, was deemed sufficient for investigating the present research. In particular, The data analysis method is based on Nugroho and Arsegianto's (1993) approach. The difference between the present study and their study is the decision stages involved in each of the methods and the critical decision factors considered to arrive at the conclusions. We believe that market and operational factors are critical for any gas development project and therefore we focus on factors such as taxes, production rates and efficiency, to reach a decision in this research.

Whereas Nugroho and Arsegianto (1993) focus was on the effects of peak production, production decline rate, and flow efficiency rate, we believe that market factors as well as geology, and operational factors such as costs, and methods of depreciation of investment and reserves do have implications for the economics of CBM development. We therefore consider all these factors as well as the optimality of fiscal incentives to reach a conclusion in this research. The following sections give a systematic explanation of the analytical approach used.

3.2.1. Step 1: Base Case Modeling of Field X

The Base Case model was used to generate the results of the cash flow analysis as would be the case for companies operating under the existing CBM PSC. It is on the basis of this Base Case that all subsequent simulations were performed to arrive at our recommended PSC.

3.2.1.1. Location of Field X

The Base Case was built based on Stevens and Hadiyanto's (2004) reserve estimate of 453.3 TCF. Since all CBM fields in Indonesia are located onshore, Field X was assumed to be located onshore in the South Sumatra Basin. The reason is that the South Sumatra Basin has the most CBM resources, and already has well established oil and gas infrastructure. The South Sumatra Basin also has the best access to market and hence it is assumed to have the best prospective for CBM gas.

3.2.1.2. Recoverable CBM Reserves

CBM production data for Indonesia is unavailable. Hence, a volumetric estimate of gas-in-place (GIP) was determined based on sorbtion isotherm. Thus, the GIP for coal is a function of the maximum original amount of gas that coal can store at equilibrium conditions under certain pressure and temperature. Additionally, the net usable area, net coal thickness, coal density, and ash content, all combine to determine the volume of GIP - see equation (1). Finally, a recovery factor is applied to estimate the commercial volume of gas that can be produced – see equation (3). The recoverable reserves were estimated using the following models:

<u>Equation 1:</u>

$$GIP = \Big((Gross\ km^2\ \times\ 247\ \times\ usable\ area) \times Net\ Coal\ Thickness \\ \times\ \big(1 - (ash\ moisture\ content)\big)\ \times Gas\ Content\ \times Coal\ Density\Big) \ldots.(1)$$

<u>Equation 2:</u>

$$\frac{GIP}{1billion} = GIP\ (Bcf) \ldots.(2)$$

<u>Equation 3:</u>

$$Recoverable\ Reserves = GIP\ (Bcf) \times Recovery\ Factor\ \ldots.(3)$$

All the parameters in the model above, such as gross km^2, usable area, net coal thickness, ash moisture content, gas content, coal density, and recovery factor were based on a range of characteristics as summarised in Table 3.

INSERT TABLE 3 HERE

3.2.1.3. Well Schedule and Production Rate

The assumption on well schedule for Field X was benchmarked against Ferdian *et al*.'s (2014). The difference is that Field X stops to drill new production wells from year 20 out of 30 years of the field life. Figure 3 illustrates the yearly production rate of Field X.

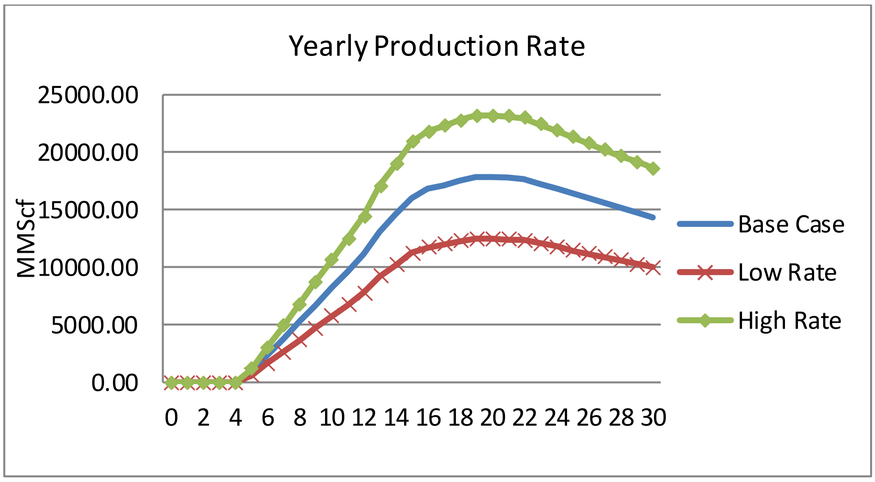


Figure 3: Yearly Production Curves of Field X for All 3 Production Scenarios

3.2.1.4. Cash Flow Modelling

<u>Fiscal Incentives Sensitivity Analysis</u>

After the Base Case results were obtained, the next step was the incentive sensitivity analysis modelling. In this step, all the sensitivity results were determined to be either favourable or not. To determine which scenario was best, three investment appraisal methods NPV, PBP, and IRR were applied. Equation 4 specifies the NPV model. These methods were chosen because they form the basis of economic evaluation of field development decisions in most oil and gas company.

Equation 4:

$$NPV(r,t) = \sum_{t=0}^{n} \left[\frac{NCF_t}{(1+r)^t}\right] \ldots . (4)$$

Where r is the discount rate – assumed as 10% in this paper and NCF represents the estimated net cash flows defined in equation 5 as follows:

Equation 5:

$$NCF = (CR + CPG - COPEX - CCAPEX - TAX) \ldots (5)$$

It must be noted that our model for NCF is for a PSC regime in Indonesia and differs from the general PSC cash flows in a typical PSC contract. Our computation of NCF recognises that an contractor's net cash flows in this regime derive from their share of profit gas (SPG), reimbursements for cost recovery (CR), contractor operating expenditure (COPEX), capital expenditure (CCPEX) and taxes.

3.3. Summary of Model Assumptions

The assumptions used in this research are summarised in Table 4.

INSERT TABLE 4 HERE

Gas recovery factor was varied from 10% up to 65%. Well drilling cost in Indonesia is assumed to range from US$ 1.5 and 2 million per well. The cost of exploration/core wells in Indonesia ranges from US$0.6 to 1.5 million/well. The operating costs are assumed to range from US$ 1.37 to 2.55 per million cubic fee (Mmcf). The gas price is projected at US$

7.5/Mmcf, but was varied from US$ 6 to 8/Mmcf. We assume a gas price escalation clause in the CBM contract and consequently the gas price at 3% per year.

4. Results and Discussion

Table 5 presents the results of the cash flow and factor analyses. The table includes the economic results of the impacts of depreciation methods of the existing fiscal regime (Base Case results) as well as the simulated results for two additional methods, the 5-year straight line depreciation (SLD) and 10-year SLD methods. The same Table also compares the economic indicators of the three fiscal regimes, including the base case to represent the present CBM fiscal regime.

INSERT TABLE 5 HERE

4.1 Impact of the Choice of Depreciation Method

In Indonesia, Government Regulation 79 mandates upstream oil and gas companies to depreciate their assets based on the reducing balance method (RBM) at 25% per year. The results of this study however indicate that the five years SLD expedites contractor cost recovery and reduces the depreciation time for assets by 5 years. Expectedly, such accelerated depreciation results in almost $3 million additional contractor NPV and fully pays out contractor investment one year earlier than the existing PSC as seen in Table 5. This evidence thus presents a supported approach which could be adopted by the Government of Indonesia to achieve its objective to incentivise CBM investments through accelerated capital cost recovery.

Although, Article 16 of Regulation 79, as amended by Regulation 27, now permits companies to cost-recover the residual value of assets deemed to be "no longer able to be used" (PWC 2017) as operating expense outright, such amendment fails to recognise the implication of the depreciation approach and time on contractor cost recovery for all other classes of assets, including those able to be used for petroleum operations. This research thus suggests further guidance on the choice of depreciation approach as well as the useful life of assets, to complement the amendments of Article 16 as enshrined in GR 27.

4.2 A New PSC Regime for CBM Development

To recommend a suitable PSC regime for the present CBM industry in Indonesia, the country's laws on upstream petroleum operations must be considered. As stated by Ferdian *et al*. (2014), the Government of Indonesia should have most of the hydrocarbon revenues, based on Indonesian Basic Law of 1945. Oil and Gas Law No. 22 of 2001 further stipulates Government's objective for increased state income from oil and gas operations (PWC 2017; 2018). Consequently, in this research, fiscal terms that generate GT which is 10 percentage points lower than the existing fiscal requirement of 55% – i.e. GT lower than 45% are deemed as failing to satisfy boundary conditions and are eliminated. As Table 5 demonstrates, the PSC with the fiscal regime based on 5% FTP, 78% CS and 30% corporate tax fails this test and it is thus removed.

Mian (2010) states that the profit expectation of the contractor and the Host Government is one of the boundary conditions that can be used to guide the design of efficient fiscal regimes for oil and gas. The profit expectation of the government could also mean how much the government is willing to sacrifice to develop their natural resource. Thus, although Indonesia's oil and gas law 22/2001 requires 55% of ETS, the infantile state of CBM development should be considered in the design of a fiscal regime. Given that development efforts have just been started with activities still at the exploration stage, it is necessary that government policy is geared towards attracting investment to explore the full potential of the resource. This should then immediately enable investment commitment from industry to develop the resource. It would be most rational that the government objectives for CBM development are phased and a policy which focuses less on taxing CBM revenues are introduced, at least for a term of CBM development which should not exceed 25 years.

Although, the Government's amendment of GR 79, with GR 27, offers some flexibilities on cost recovery, contractor use of upstream state-owned facilities, tax and regulatory climate, among other non-income related reforms, it would be most beneficial for Government to recognise the special nature of unconventional resource development and define further incentives for industry to expedite development. Government fiscal policy which focuses on reduced taxes and essentially moderate Government revenue expectations should be viewed as Government's contribution to investments towards the development of CBM in Indonesia, in line with petroleum fiscal design thoughts suggested by Mommer (2000) and Baunsgaard (2001). Following a successful establishment of the industry, a second phase of CBM development may be defined within which government may review its objectives in favour of recovering a fairer share of income from CBM. Presently, the country still needs to attract investors so that CBM resources can be fully unlocked. Optimal Government policy should consequently focus on instilling confidence in investors rather than laying down structures to tax off revenues which may not flow in due to lack of investment in the resource.

One way to increase the attractiveness of CBM development in Indonesia is by incentivising CBM development contracts to grant further certainty to investors on capital recovery. Government Regulation 27 attempts to achieve this through the reclassification of interest cost, community and environmental costs which were non-cost recoverable under GR 79. This amendment is particularly important for CBM development because the related environmental costs for the resource are particularly high. Other incentives recently introduce by the Government such as the exemption of operators from import duties and the permission of operators to recover liquified natural gas (LNG) processing costs as contained in Articles 26 and 11 respectively, are timely.

Nonetheless, there is still a lack of clarity in some aspects of GR 27, which further introduces uncertainty into CBM in particular and oil and gas development projects in general. Article 10 of GR 27 grants a DMO holiday to contractors. Whilst this is generally within the spirit of achieving certainty of cash flows and expedited contractor cost recovery, it is unclear from Article 10 when the DMO holiday terminates, hence failing to eliminate uncertainty. Article 10 (a) also stipulates a sliding scale for ETS, to be determined by the MEMR, yet it is unclear how the sliding scale will interact with split formula indicated in the PSC itself (PWC 2018). This gap could potentially sabotage government efforts to attract investment. Furthermore, the discretion granted the MEMR over uplift, import duties, profit gas split is less desirable than a definitive scientific approach to arrive at contractor cash flows. A CS of after-tax revenues above 50% could increase the attractiveness of CBM contracts as it could enable an achievement of the government objective to “Guarantee effective, efficient, highly competitive and sustainable exploration and exploitation” (Oil and Gas Law 22/2001;PWC 2017:15) with minimal financial detriment to the government. However, as illustrated in Figure 4, 50% CS after tax is impossible to achieve under the existing PSC regime. The current ETS ratio for CBM is 55:45 after tax, in favour of the government.

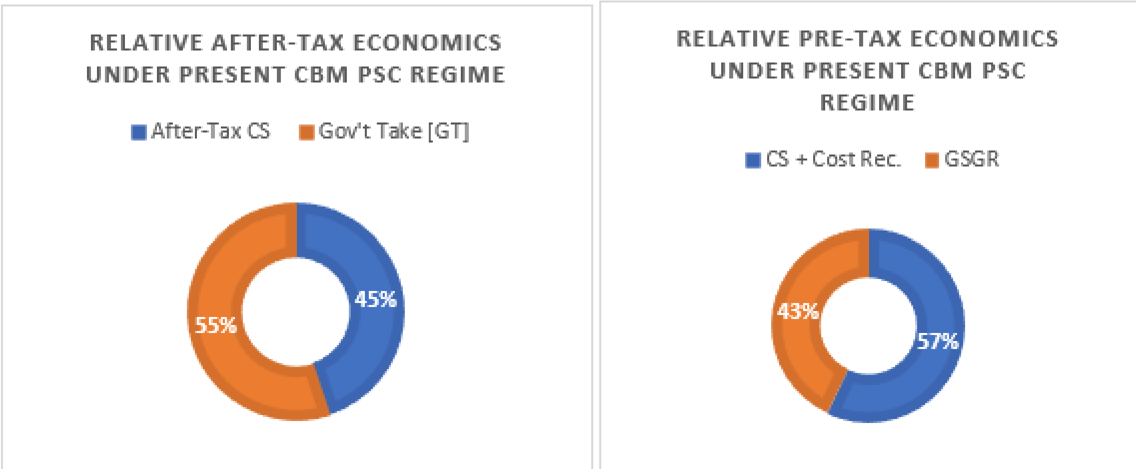


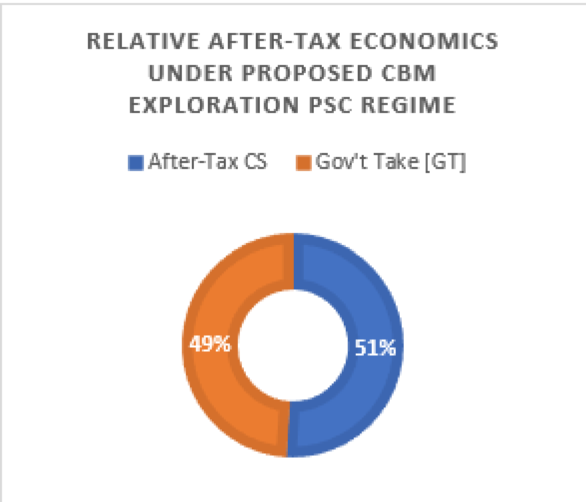
Figure 4: Government Take [GT] and Contractor Share of Gross Natural Gas Revenues

Figure 4 shows Government Take [GT] and CS of Gross Natural Gas Revenues after tax (left) and Government Share of Gross Natural Gas Revenues [GSGR] Relative to CS including Contractor Cost Recovery [CS+ Cost Rec.] at 57% only under the Current Indonesian PSC Fiscal Regime (right). These indicate a rather high Contractor Investment Risk and will most certainly increases investor risk premium for CBM development.

As presented in subection 2.3, the current Indonesian PSC already provides some incentives to the CBM contractors. However, these have failed to attract operator interest as evidenced by the government's failed competitive bidding rounds for unconventional licenses reported by the Insider (2018) and PWC (2018), respectively. Consequently, the regime requires reviewing to include safeguards for potential CBM operators in the light of current realities within the Indonesian oil and gas industry to inject investment momentum in CBM development. Incentives should therefore be prioritised over taxation at an exploratory phase of CBM development.

It is argued in this research and as under Table 5, the exploration PSC with a combination of 5% FTP, 35% tax, and 78% CS produces win-win economics for the government and industry. Although, Government receives 49% of income from CBM in this proposal, the resource is more likely to get developed and the contractor has increased opportunity to recover their costs plus reasonable profits. This regime is superior to the existing CBM PSC regime and therefore we argue that it is more appropriate for CBM development because it (1) satisfies government's desire to attract investment and (2) returns a reasonable income to the state.

Figure 5 presents GT of 49% against contractor take of 51%. Unconventional natural gas contracts tend to have more lenient fiscal regimes, often with a generous fiscal climate, especially where little or no prior geological history and or commercial production is known. The UK's fiscal regime for SG has been cited as generous (HM Treasury 2013) and lends credence to the foregoing argument. Relatedly, Stevens (2013) confirms that the US's SG revolution was partly possible due to significant tax breaks offered by the US Government. Johnston (2003b) states that an ideal PSC regime should allow flexibility to accommodate changes in perceived prospects and economic conditions. We are convinced that the PSC terms proposed in this research are ideal for exploration and exploitation but caution that such regime should be replaced once reasonable progress has been made into exploitation and the contractor has recovered an agreed portion of their investments.



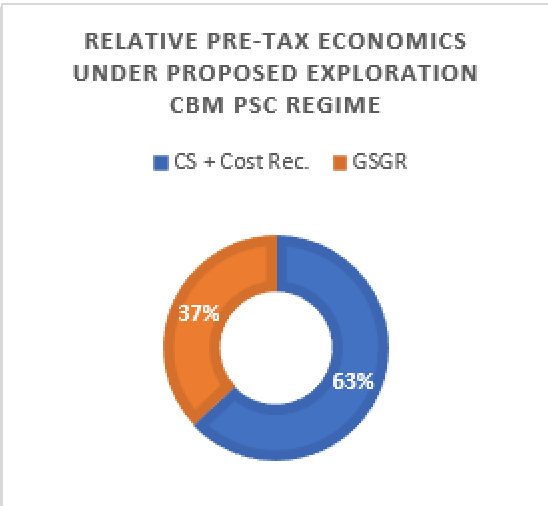


Figure 5: CBM Exploration Production Sharing Contract

Figure 5 shows GT and Contractor Share of Gross Revenues [CSGR] for the recommended PSC for CBM Exploration. This tax regime allocates more of gross CBM revenues to the contractor for their cost recovery plus reasonable profits in recognition of the higher geological risks associated with exploration of the resource given the lack of previous commercial development in Indonesia. Such regime thus emphasises risk sharing between the government and the CBM contractors via a trade-off of government revenues at the exploration stage of industry.

Historically, and as indicated in subsection 2.3, Indonesia's PSC has undergone changes in the gas revenue sharing, and certainly, modifying the current PSC to support CBM development would not be the first time. For example, and as indicated in Table 1, in the 2nd Generation PSC, the CS for gas was almost 80%. This percentage of CS later changed to 57.7% in the 3rd Generation PSC. Current conventional gas split in Indonesia is 70:30, in favour of the government. Consequently, the state needs to adapt its PSC to the changing risks and rewards to the development phases of CBM. Petroleum fiscal systems have been cited to evolve in response to product price (Nakhle 2008), geological and operational factors as well as political factors. As an example, the UK doubled its supplementary charge (SC) in 2005 in response to increased oil price from $25 to over $55 per barrel (The Guardian *6 Dec 2005*). Conversely, oil and gas producing countries cede fiscal taxes to industry as incentives during low price and poor geological regimes to attract investment (Mansour and Nakhle 2016). For example, Norway abolished royalty from its petroleum fiscal regime in 2000 to attract investment (Holterud 2011). In other words, governments do tighten their fiscal terms in response to increased investments and more favourable operational and market conditions (Ivan *et al.* 2015; Wood Mackenzie 2015; Ward 2009; Clarke and Cummins 2012) to satisfy their revenue objectives more fully.

For emerging unconventional oil and gas producing countries, such flexibility in fiscal regimes is especially required to efficiently and effectively develop their natural resources due to the higher cost and remarkably high risks associated with the resource. Nakhle (2016) suggests that price is a fundamental determinant of host governments' bargaining power in oil and gas contract negotiations. The author adds that host governments' bargaining power may be weak due to low oil price, lack of infrastructure, political stalement, delays in decision making and security risk. We extend this argument and suggest that for countries that are new to the exploitation of unconventional natural gas and indeed all forms of hydrocarbons, regardless of the quality of geology, market or operational factors, the relative bargaining power of the states, are lower due to the inherently higher geological risks. Host governments must thus recognise this and design the most suitable fiscal regimes that support the development of their resources. Bargaining power, which should also translate into revenue earning power for the states may even be far lower if the resource to be invested in and exploited is unconventional, as it carries more risks to develop (*see* Acquah-Andoh 2015). Governments must thus be ready to cede taxes and offer even more incentives and support that encourage investment in the resource. At the exploration phase CBM development in Indonesia will thus thrive well under the 'exploration phase' PSC on the foregoing fiscal conditions. Relatedly, to bridge the gap between an exploration PSC to exploitation PSC regime, a 'Transitional PSC', which comprises 5% FTP 49% CS and 35% corporate tax is proposed.

Table 6 present the two-factor analysis of the transitional PSC terms.

INSERT TABLE 6 HERE

As Table 6 demostrates, the terms are suitable for transitional PSC because government can better increase GT progressively from 49% to 51% and eventually back to 55%. After the transitional PSC regime, the government may return to a GT of 55% to achieve its financial objectives of the Oil and Gas Law 22/2001 or apply an entirely new regime. The dynamics of the oil and gas industry require the design of petroleum fiscal regimes to adapt to the changing realities of industry. Indonesia possesses enormous experience of managing fiscal regime transitions that have arisen as a result of changes in petroleum laws (*see* Table 1 for Indonesia's historical PSC regimes). For example, PWC (2018) and Deliotte (2017) report that the country amended GR 79 on oil and gas operations and replaced it with GR 27, where the government outlined transitional procedures and rules to govern the process from GR 79 to GR 27. A change from the 'exploration phase' PSC to an exploitation phase PSC via a transitional PSC thus appears to be a familiar practice in Indonesia, and this is most suitable for CBM development in the country.

The foregoing analysis emphasises risk sharing between the state and the contractor but progressively increases government receipts as the CBM industry matures. That way, the contractor can recover more of their investment and adapt to changes in progressive PSC regimes. Such reasoning is consistent with petroleum fiscal design objectives. Consequently, for Indonesia, a substantive 'exploitation phase' PSC regime which adapts to the relatively lesser geological risks faced by industry at the production phase compared to the exploration phase should thus become the fiscal framework that governs CBM production after the transitional phase. As indicated in Figure 6, the government may apply the 'exploitation phase' PSC (New PSC Term) with these terms: (1) increased FTP to 10%; (2) reduced CS to 60% (before tax) and (3) increased corporate tax to 45%. The results of this new PSC regime are presented in Figure 6.

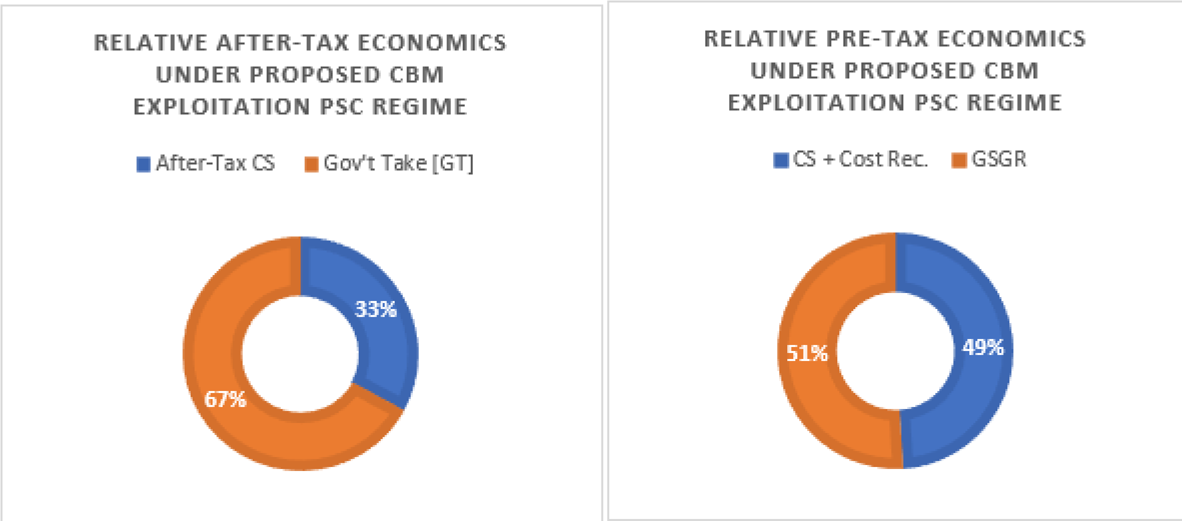


Figure 6: Proposed PSC for CBM Exploitation

Figure 6 demonstrates progressive government take [GT] and GSGR from the transitional PSC, in light of the relatively lower geological uncertainty faced by CBM contractors at the production stage compared to the higher risks at the infantile/ exploration phase of industry.

By applying the above terms and, as Figure 6 illustrates, GT and GSGR could reach up to 67% and 51% respectively, to fully meet the requirements of law 22/2001. This approach should better satisfy Indonesia's revenue expectations from oil and gas development, whilst securing optimal investment to unlock the full potential of its CBM resource at the exploratory stage of the industry.

4.3 The Impact of Gas Price, Capital Cost, Operating Cost, and Production Rate

The ability to overcome the effects of fluctuations in costs, gas price, and rate of production will be necessary to ensure CBM is viable in Indonesia. Figure 7 compares the IRR from the sensitivity analysis performed on the existing PSC and the proposed CBM exploitation PSC scenarios.

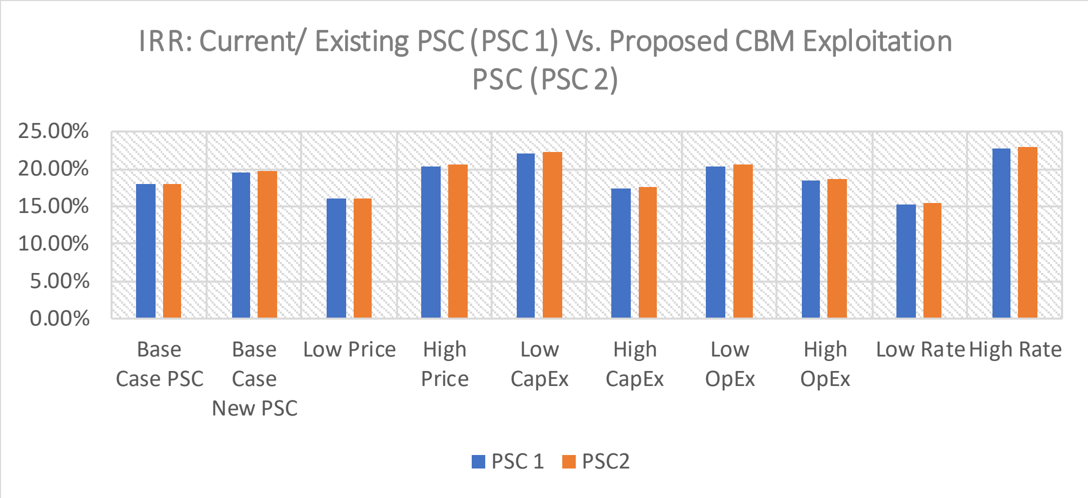


Figure 7: The Relative Returns of the existing PSC and the proposed CBM Exploitation PSC

Figure 7 shows a comparison of returns for CBM contractors relative to fluctuating operational and market conditions under the existing PSC (PSC 1) and the Proposed PSC (PSC 2). PSC 2 shows superior resistance and viable economics to changes in production flow rates, natural gas price, operating expenses [Opex] and capital expenses [Capex].

As Figure 7 shows, the high rate scenarios give the best IRR, while the low rate scenarios turn out to be least attractive. However, a conclusion about the most significant parameters cannot be made based solely on the charts. To give a clearer illustration of the most critical parameters, the spider diagram of the NPV for the proposed CBM exploitation PSC (PSC 2) is required, and it is presented in Figure 8.

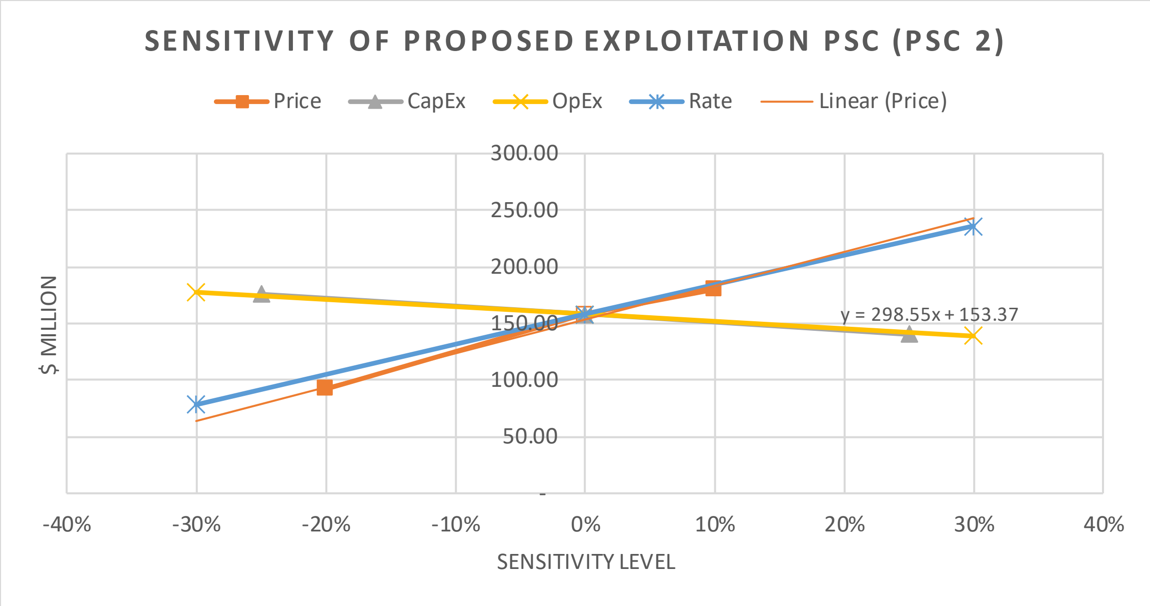


Figure 8: Sensitivity of Proposed CBM Exploitation PSC Regime

Figure 8 illustrates the responsiveness of the proposed CBM exploitation PSC cashflows to the most critical factors of investing in CBM. It is revealed that natural gas price is the most critical factor in CBM exploitation. As price cannot be controlled by a CBM contractor, it is even more imperative that government tax regime be designed to safeguard investor capital by sharing in the risks to CBM development via reasonably reduced state tax income at the exploration phase of industry.

From Figure 8, the gas price gradient is steepest and most sensitive. It is therefore clear at this point that gas price poses the most risk to the cash flows, but gas price is one parameter that CBM contractors cannot control. Government tax policy on CBM would thus need to be crafted to provide reasonable protection for investor capital whilst at the same time assuring them a reasonable return on their investment. It seems that our proposed PSC framework offers a more rational approach to attract investments to develop CBM in Indonesia.

5. Conclusion and Policy Implications

The potential of CBM development in Indonesia is huge, which is at an estimated 453 TCF. Despite this, not much investment has been attracted to the development of the resource, with an estimated US$48.2 billion required investment to develop natural gas infrastructure. In this study, we investigated options for attracting investment to the

Indonesia's CBM industry with particular focus on the review of the PSC incentives as government's immediate policy. We find, and consequently argue, that a combination of 5-years SLD and reduced FTP to 5% and income tax to 35% have the potential to increase CS to 78%, without significant reduction in the government's share of revenues. This proposal reflects the degree of government's bargaining power for CBM investments and earning power towards CBM profits, at this early stage of the industry, and it is more likely to attract investment interests into CBM development in Indonesia.

Our cash flow simulations returned a GT of 49% rather than 55%, and increased the Contractor's Take (CT) from 45% to 51%. This proposal offers more certainty of contractor cash flows and promises to be an optimal government policy at an initial stage of CBM development to establish the industry, build a better understanding of the CBM potential of the country and position the country to unlock the full benefits CBM may offer. After exploration and in response to improving operational, market and project conditions, a more tax-focused regime may be designed, such as our 'exploitation phase' PSC, to capture a fairer share of CBM revenues. The post-transition/ 'exploitaion phase' PSC is a combination of increased FTP to 10%, reduced CS to 60%, and increased tax to 45%. This PSC regime can generate GT of up to 67%, and the GSGR of 51%.

To bridge the gap between the recommended initial PSC regime at this infantile stage of CBM development and the exploitation phase PSC regime, a transitional PSC, which is a combination of reduced FTP to 5% and reduced tax to 35% may be adopted. For better economics, the PSC must permit a contractor to depreciate their assets based on a 5 years SDL for tax purposes and to enable an accelerated recovery of their costs and investment. Such policy is required to incentivise investment in CBM in emerging countries where gas price has traditionally been low to support investment and where natural gas infrastructure tends to be weak.

In addition, we argue that for countries that will be commercialising potential unconventional natural gas, the partuclarly high geological and thus investment risks offer host governments relatively weaker bargaining and hence earning power. We thus argue that the proposed petroleum fiscal regime would better attract the required investment to develop Indonesia's CBM resource and should provide direction to emerging countries looking to commercially develop unconventional resources for the first time. Consequently, it would be a good policy direction for the government of Inonesia to initiate a review of the fiscal policy that governs CBM in order to spur momentum into the resource's development.

Overall, the current research offers a proposal of what would be an optimal fiscal policy to attract investment to develop CBM in Indonesia. It also offers some critical fiscal policy recommendations for emerging countries, that would be developing their unconventional natural gas for the first time. However, it may be necessary for future research to focus on estimating the effects of the underlying geological and market uncertainties on the value of CBM contracts. In that way, a definitive cut-off point for the introduction of a transitional PSC could be recommended. To complement the findings of this research, a Monte Carlo approach or real options approach that models uncertainty into, and investigate the impacts of the behaviour of natural gas price on the profitability of CBM contracts would add further clarity to the extent to which price affects CBM contracts. Finally, an application of real options theory to research the moderating impacts and flexibility of government policy on CBM contracts would provide further insight into fiscal policy design for developing CBM resources in Indonesia, and more generally unconventional natural gas development in emerging producing countries.

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Table 1: PSC Generations of Indonesia (Johnston 2003a) [a]

Fiscal Features	1st PSC (1966)	2nd PSC	3rd PSC
FTP	Nil	Nil	20%
DMO	Contractor receives \$0.2/ barrel for 25% share of their profit oil after 60 months of production	After 60 months' production, Contractor receives \$0.2/ barrel for 25% "Share Oil" - which equals 79.5455% of contractor entitlement	After 60 months production, Contractor receives 10% of market price for 25% of their Share Oil; "Share Oil" equals 28.8462% of Contractor entitlement
CRL	40% of gross production	No Limit	80% Limit
Taxation	Nil	56% effective tax	48% effective tax
ETS	65% Government, 35% Contractor	Oil: 65.9 % Government; 34.1% Contractor Gas: 20.5% Government; 79.5% Contractor	Oil: 71.2 % Government; 28.8% Contractor Gas: 42.3% Government; 57.7% Contractor

a Table 1 shows the various PSC generations that Indonesia has had since oil and gas production. The Table shows that Indonesia has gone through three main PSC generations, but that the three fiscal elements of its PSCs are fairly constant since 1966, with First Tranche Petroleum [FTP], Cost Recovery Limit [CRL], Domestic Market Obligation [DMO], Equity Oil/ Gas to be Split [ETS] and Income Tax being the main features of all fiscal regimes.

Table 2: Relevant Tax Features of Government Regulation 27

Area of Regulation	Relevant Subject	Amendment/ Incentive
Article 10	State Revenues, including FTP	Domestic Market Obligation (DMO) holiday, although it is unclear when this terminates. Contractors can now use state-owned infrastructure for upstream activities at a charge potentially free of VAT and withholding tax. A new sliding scale for sharing equity oil/gas, thus recognising the effects of changes in price and production volume.
Article 11	Recoverable LNG Processing Costs	Amended to allow for recovery of Liquified Natural Gas [LNG] processing costs incurred up to the point of delivery, as exploitation costs.
Article 13	Non-recoverable Costs Revised, as Recoverable	Community development and environmental costs during exploitation phase of projects, employee income tax borne by the contractor now paid as tax allowance (using grossed-up method), interest costs, are now cost recoverable. Thus, spending relating to items which were not cost recoverable under GR 79 are now cost recoverable
Article 16	Residual Value of Assets "no longer able to be used"	Amended to allow the residual value of assets "no longer able to be used" to be fully cost recovered outright. Under GR 79, such asset would continue to be depreciated on the basis of the original useful life of the asset.
Article 26		Import duty exemption for goods imported in relation to petroleum operations in the exploration and exploitation phases. Reduced subsurface land and building tax of 100% during exploration phase and up to 100% during exploitation phase. Incentives at the exploration phase are subject to the Minister of Finance approval.
New Article 27	Tax on Uplifts and Transfers	Taxable income arising from uplifts and PSC transfers, after being reduced by final income tax, should not be non-taxable. Thus, these items should not be subject to any further from this point on.
	State Owned Facilities – Processing, Transportation, Storage and Sales	With the permission of the Special Taskforce for Upstream Oil and Gas Business Activities (SKK Migas), a contractor can now use spare capacity on upstream state facilities with a potential zero withholding tax and VAT on the charge for using such facilities.

Source: PWC 2018; Deloitte 2017

Table 3: Characteristics of and CBM Reserves of Field X

Field X	Estimate
Gross km^2	820
Useable Area	63%
Net Coal Thickness (ft)	144
Ash Moisture Content	21%
Gas Content (Scf/ton)	160
Coal Density (Ton acre/foot)	1800
Gas in Place (Bcf)	4214
Recoverable Reserves (Bcf)	421

Ft = feet, Scf = standard cubic feet, Bcf = billion cubic feet

Table 4: Assumed Geological Characteristics and Market Conditions for CBM Development (Reservoir Characteristics were sourced from Steven and Hadiyanto 2004)

	Low Case	Most Likely	High Case
Gross Square Kilimetre	519	580	1362
Useable Area (%)	55	65	70
Net Coal Thickness (ft)	115	158	160
Ash Moisture Content (%)	15	20	28
Gas Content (Scf/ton)	130	150	200
Gas Price ($/Mmcf)			1.75
Exploration Cost ($M/Well)			1.05
Well Cost ($M/well)			1.75
Operating Costs ($/Mmcf)			1.96
Operating Costs during Dewatering Phase ($'000)			100
Total Investment ($M)			1.75
Operating Days in a year (Days)			365

Ft = feet, Scf = standard cubic feet, Mmcf = million cubic feet, $M = million US dollars

Table 5: All Fiscal Factors Combination Analysis [d]

Sensitivity	Indicators	Existing PSC Method: Decling Balance Analysis	Straight-Line Depreciation 5 Years	Straight-Line Depreciation 10 Years
Base Case	IRR (%)	18	18	17
	PBP (Years)	12	11 .75	13
	NPV @ 10% ($M)	121	124	114
	Gov't Take (%)	55	55	55
	Gov't Share of Gross Revenues (%)	43	43	43
	Contractor After tax Share of Revenues ($M)	1,096	1,096	1,096
	Contractor After tax Share of Revenues (%)	45	45	45
	Contractor Share of Revenues plus Cost Recovery ($M)	2,280	2,280	2,280
	Contractor Share of Revenues plus Cost Recovery (%)	57	57	57
Exploration PSC FTP = 5% ; CS = 78%; Tax = 35%	IRR (%)	19	20	19
	PBP (Years)	11 .75	11	12
	NPV @ 10%($M)	156	158	149
	Gov't Take (%)	49	49	49
	Gov't Share of Gross Revenues (%)	37	37	37
	Contractor After tax Share of Revenues ($M)	1,337	1,337	1,337
	Contractor Share of Revenues plus Cost Recovery (%)	51	51	51
	Contractor Share of Revenues plus Cost Recovery ($M)	2,521	2,521	2,521
	Contractor Share plus Cost Recovery (%)	63	63	63
Eliminated PSC FTP = 5% ; CS = 78%; Tax = 30%	IRR (%)	20	20	19
	PBP (Years)	11.5	11	12
	NPV @ 10%($M)	169	171	163
	Gov't Take [GT] (%)	45	45	45
	Gov't Share of Gross Revenues (%)	35	35	35
	Contractor After Tax Share of Revenues ($M)	1,439	1,439	1,439
	Contractor After tax Share of Revenues (%)	55	55	55
	Contractor Share of Revenues plus Cost Recovery ($M)	2,624	2,624	2,624
	Contractor Share of Revenues plus Cost Recovery (%)	65	65	65

[d] Table 5 shows four potential production sharing contracts, with different PSC terms. The table indicates that a fiscal regime with 5% First Trance Petroleum [FTP], 78% Contractor Share of revenues [CS] and 30% tax are most suitable for CBM exploration and development compared to the existing PSC (Base Case) or third PSC regime with 5% FTP, 78% CS and 30% tax. The base case PSC appropriates risks to CBM contractors, the 'Eliminated' PSC is overly generous and fails to reasonably meet government revenue objectives and is thus eliminated from the PSC options. The different colour codes represent the results of different potential PSCs, with 5% FTP, 78% Contractor Share and 35% corporate tax being the superior and optimal tax policy – the 'Exploration PSC'.

Table 6: Transitional PSC Terms: Results of the Two-Factor Analysis [f]

FTP = 5% ; CS = 49% Tax = 35%	IRR (%)	19	19	19
	PBP (Years)	11.5	11	12.5
	IRR (%)	149	152	142
	Gov't Take [GT] (%)	51	51	51
	Gov't Share of Gross Revenues [GSGR] (%)	38.6	38.6	38.6
	Contractor Share of Revenues after Tax ($M)	1,285	1,285	1,285
	Contractor Share of Revenues after tax (%)	49	49	49
	Contractor Share of Revenues plus Cost Recovery ($M)	2,469	2,469	2,469
	Contractor Share of Revenues plus Cost Recovery (%)	61	61	61

[f] Table 6 Shows the proposed PSC regime for CBM development during a transition from the 'exploration' PSC onto a substantive 'exploitation phase' PSC. The Table presents most viable government and contractor share of CBM revenues at 5% First Tranche Petroleum [FTP] and 35% income tax. Such PSC regime better recognises contractor risks and more suitably rewards investments in CBM. The Transitional PSC can enable Government to increase GT progressively from 49% to 51% and eventually back to 55%.