The Thesis Committee for Dong Hyun Kim
Certifies that this is the approved version of the following Thesis:

Economic Analysis and Risk Management for the South Sumatra Natural Gas Pipeline Project in Indonesia

APPROVED BY
SUPERVISING COMMITTEE:

David J. Eaton, Supervisor

Richard J. Chuchla

Patrick L. Brockett

Economic Analysis and Risk Management for the South Sumatra Natural Gas Pipeline Project in Indonesia

by

Dong Hyun Kim

Thesis

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Energy and Earth Resources

The University of Texas at Austin

May 2019

Dedication

To my devoted wife, Ji Young Kim,

and lovely sons, Jeong Yoon Kim and Chae Yoon Kim.

Acknowledgements

I would like to express my gratefulness to the members of my thesis committee: David Eaton, for his excellent observations and encouragement that enabled me to complete my research; Richard Chuchla for his in-depth knowledge and experience in energy industry; and Patrick Brockett for the incredible time in spite of his busy schedule.

My heartfelt thanks go as well to Korea Gas Corporation for giving me a great opportunity to study in the University of Texas at Austin and to the Mount Fuji Cell in Evergreen Church for devoting themselves to my family with love and prayers.

I am deeply indebted to my lovely wife for her entirely devotion that enabled me to concentrate on the master program for two years and to my sons who made me happy and positive in any circumstances. I also thank my parents, parents-in-law, my younger sister, and all my family for their prayers and unconditional love.

Above all, I am thankful to God for His guidance and help for me to finish the master program in the University of Texas at Austin by providing several helpers and wisdom in any circumstances.

Abstract

Economic Analysis and Risk Management for the South Sumatra Natural Gas Pipeline Project in Indonesia

Dong Hyun Kim, M.S.E.E.R.

The University of Texas at Austin, 2019

Supervisor: David J. Eaton

The objective of this thesis is to analyze economic and risk factors for the South Sumatra Natural Gas Pipeline Project in Indonesia. The economic analysis aims to support Korea Gas Corporation (KOGAS)'s decision regarding next steps, such as a feasibility study or front end engineering design for the project. In scenario analysis, WACC ought to be less than 9 percent and the growth rate of gas demand is larger than 3 percent to meet KOGAS's requirements for an investment. Monte Carlo simulation showed that the project has a project NPV of 90 million USD and project IRR of 11 percent on Scenario 1 which is the least profitable scenario. It means that this project could be a viable project for KOGAS, but there is a 36 percent probability that the project IRR would be less than KOGAS' investment threshold. A sensitivity analysis indicates that a toll fee has the greatest impact on the project IRR among six variables. This thesis establishes mitigation strategies against the South Sumatra Natural Gas Pipeline Project's significant risks.

Table of Contents

List of Tables

List of Figures

Chapter 1: Introduction

1.1 Background

The world economy is expected to almost double over the next 20 years, which will increase the need for energy, even if the extent of the added demand will be mitigated by a decrease in energy intensity [1]. One estimate is that world energy consumption could increase from 575 quadrillion British thermal units (BTU) in 2015 to 736 quadrillion BTU by 2040, or a 28 percent increase [2]. Natural gas, the world's fastest growing fossil fuel, has increased by 1.4 percent per annum (p.a.), compared with petroleum's 0.7 percent p.a. growth and virtually no growth in coal use [2]. Increased natural gas demand could create energy business opportunities.

As the world's eighth-largest energy consumer in 2017, South Korea relies on imports to meet about 98 percent of its fossil fuel consumption due to insufficient domestic resources [3]. To secure Korean energy resources, the Korea Gas Corporation (KOGAS), a state-owned company, participates in upstream to downstream natural gas and oil business through potential projects in promising countries. KOGAS' participation in diverse projects not only enables Korean private companies to join such projects for shared growth, but also strengthens capabilities to implement many types of energy projects.

Indonesia represents a promising nation for KOGAS, as it already is one of the world's large LNG exporters. Indonesia has been experiencing dramatic changes due to an abrupt increase in natural gas consumption with its rapid economic growth [4]. The consumption of natural gas in Indonesia may reach 54.37 billion cubic meters (BCM) in 2035, a 66 percent increase compared with the 2018 consumption of 32.69 BCM [5].

This large additional gas demand will require additional gas infrastructures such as LNG plants and gas transportation facilities. Indonesia welcomes international company investments in those facilities [4]. To attract foreign investment, the Indonesian government is reforming its energy sector to address regulatory burdens and lack of legal transparency [6].

KOGAS has participated in the Senoro-Tolli production and the Donggi Senoro LNG (DSLNG) liquefaction projects in Indonesia since 2011. KOGAS has been discussing the development of a South Sumatra Natural Gas Pipeline Project with a local Indonesian company. According to the State of South Sumatra, the rapid urbanization and industrial growth in South Sumatra could create significant energy demand, especially in Tanjung Api-Api (TAA), which has been designated as a Special Economic Zone (SEZ) by the Government Regulation number 51 of 2014 (No. 51/2014) [7]. Prior to further steps, which would include a feasibility study (FS) or front end engineering design (FEED), KOGAS intends to research a proposed South Sumatra Natural Gas Pipeline Project.

1.2 Objectives of Thesis

During the visit of Indonesian President Joko Widodo to Korea in 2016, KOGAS signed a memorandum of understanding (MOU) with an Indonesian company for the South Sumatra Natural Gas Pipeline Project. In this MOU, KOGAS agreed to conduct a feasibility study to decide whether or not to proceed further.

According to KOGAS's administrative guidelines, a feasibility study prior to FEED needs the approval of an internal committee. Before a feasibility study, KOGAS prefers undertake a prefeasibility study to analyze the economic viability of the project, assess risks which might occur during the project period, and establish a strategy to execute the pipeline project successfully. This thesis performs such an economic analysis, based on an anticipated natural gas demand and estimated project cost including capital expenditures (CAPEX) and operating expenses (OPEX). This thesis also calculates a net present value (NPV) and internal rate of return (IRR) to evaluate whether the project can meet a minimum 10 percent IRR required by KOGAS for an investment. As indicated in Table 1, it identifies significant risks and establishes mitigation strategies (see Table 1).

Table 1: Stages of Analysis

No	Stages
1	Estimation of natural gas demands from electricity and industry needs in gas supply points
2	Analysis of the gas pipeline capacity for the gas flow
3	Analysis of the availability of natural gas sourcing from gas fields based on estimated gas demands
4	Calculation of the expected revenues with an assumed toll fee and estimated gas demands
5	Calculation of the CAPEX and OPEX by using historical data and literature review
6	Economic analysis to calculate NPV and IRR from a future cash flow using @Risk software
7	Sensitivity analysis to find the most risky variables
8	Identification of significant risks and establish mitigation strategies

(Source: developed by Kim, D.H.)

Chapter 2 accounts for natural gas industry of Indonesia and regulations for a transportation business of South Sumatra Natural Gas Pipeline Project. Chapter 3 is an overview of the project, including an introduction of a Special Economic Zone in Tanjung Api-Api and an explanation about how to create revenues in a transportation business. Chapter 4 develops a method to forecast gas demands and assess the availability of gas supply from gas fields. Chapter 5 estimates project's economic viability by calculating the net present value and internal rate of return based on its discounted future cash flow. Chapter 6 discusses a risk management to minimize risks and maintain a stable operation of the project. The risk management identifies project's significant risks and establishes mitigation strategies. Chapter 7 summarizes the result of the economic analysis and risk assessment, and it also suggests recommendations for KOGAS' further steps.

Chapter 2: Natural Gas Industry and Regulations for Transportation Business

After its economic recession in 1998, Indonesia has increased the consumption of natural gas at an annual growth rate of 7 percent [8]. Among available energy resources (oil, natural gas, coal, biomass, or other renewable sources), oil consumption has accounted for the highest portion of Indonesia's recent energy mix at 38 percent in 2013 [6]. The reliance on oil creates a challenge to the Indonesian economy because it has become an importer rather than exporter of energy.

The Indonesian government planned to reduce by 2025 its oil consumption portfolio to a 25 percent maximum share, while raising the coal and natural gas portions to at least 30 percent and 22 percent, respectively, under its 2014 Energy Law [6] (see Table 2). The goal for natural gas use is for it to increase by at least 24 percent by 2050. Table 2 lists the target based on the National Energy Policy goals for a more sustainable energy resources mix by 2025 and 2050 target dates [9].

Table 2: Target of Energy Resource Mix

Energy Source	2025	2050
New and renewable energy	minimum 23%	minimum 31%
Crude oil	less than 25%	less than 20%
Coal	minimum 30%	minimum 25%
Natural gas	minimum 22%	minimum 24%

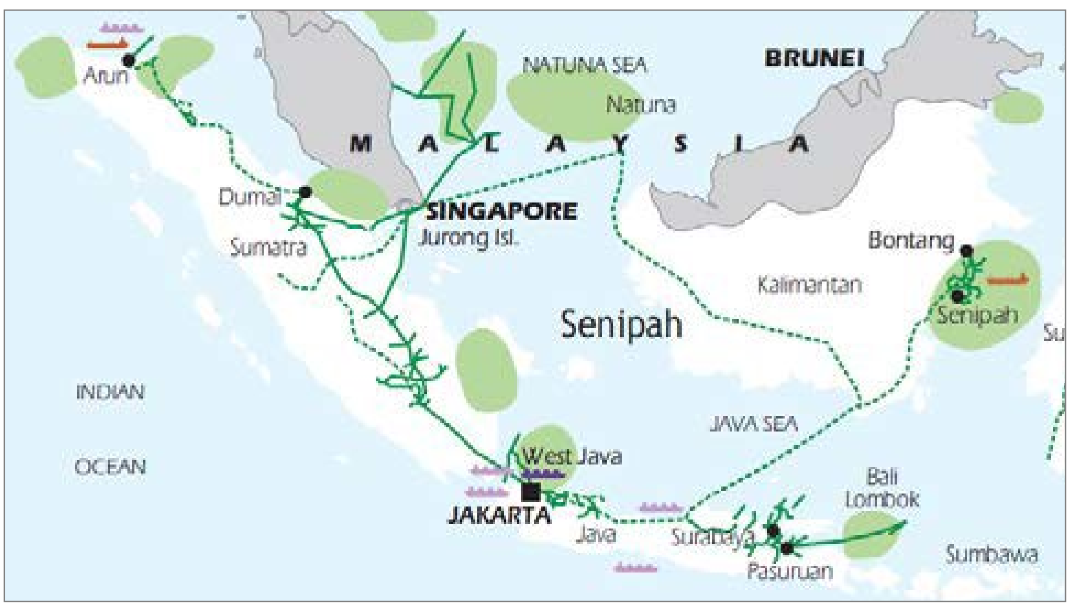
(Source: Table in page 28 from [9])

As demand for domestic gas has grown since 2013, the amount of natural gas available for export has fallen [4]. In 2005, Indonesia was the world's largest exporter of LNG. By 2016, Indonesia fell to the world's fifth largest exporter [9]. Although

Indonesia is ranked tenth in terms of global gas production with proven reserves (estimated in 2016) of 102 trillion cubic feet (TCF), insufficient investment and the lack of gas infrastructure inhibit the natural gas sector from reaching its full potential [9].

One of the barriers to increasing domestic gas use and exports is Indonesia's limited gas pipeline network. Indonesia has a combined pipeline transmission and distribution network of a total length of approximately 8,363 kilometers (km), including 4,336 km of transmission networks [4]. Indonesia's natural gas pipeline network consists of a number of fragmented point-to-point grid systems [10] (see Fig. 1). Domestic distribution infrastructure is almost non-existent outside of west Java and south Sumatra. Gas reserves are far from populations that need gas. Moving gas is complex because Indonesia consists of more than 17,000 islands. For natural gas to be useful as a fuel for a sustainable national economy, a pipeline network ought to be developed widely [4].

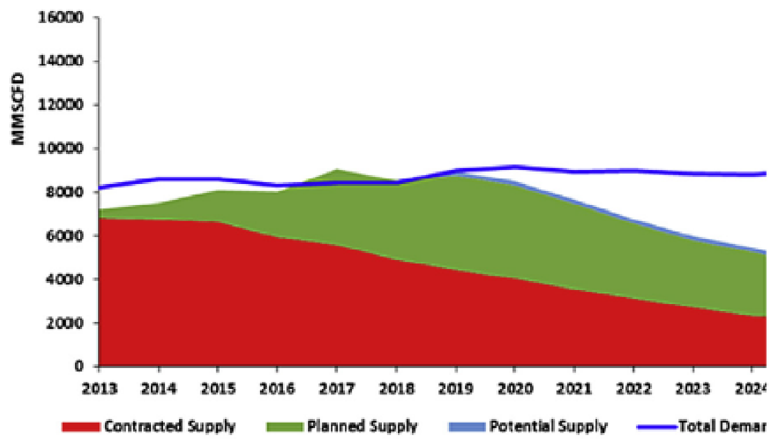
Figure 1: Natural Gas Infrastructure Map of Indonesia



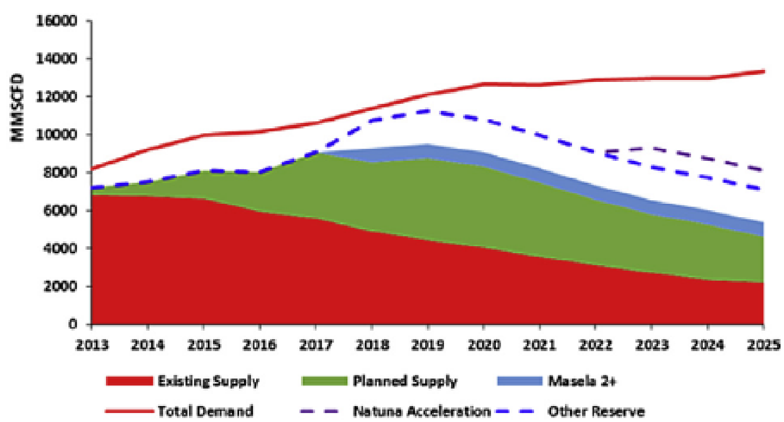
(Source: based on the figure in page 22 from [10])

PT Peruahaan Gas Negara (PGN), an Indonesian national gas company, estimated Indonesia's gas demand and supply to 2025 in accordance with GDP growth using two alternative scenarios, a 5.6 percent GDP growth and a 7 percent GDP growth rate [4]. PGN concluded that the gas supply will not be able to meet the gas demands in either scenario (see Fig. 2).

Figure 2: Indonesia's Gas Supply-Demand Gap



(a) Scenario of 5.6 % GDP growth



(a) Scenario of 7 % GDP growth

(Source: Figure 10 from [4])

Even in the scenario of 5.6 percent GDP growth, total gas demand is not satisfied with the sum of contracted, planned, and potential supplies. Indonesia will require gas imports of approximately 4,000 million standard cubic feet per day (MMSCFD) in 2025, which would be equivalent to 48 percent of Indonesia's total gas demand [4]. In the scenario of 7 percent GDP growth, the gap between supply and gas demand is larger than the scenario of 5.6 percent GDP growth.

Indonesia could reduce the gap between gas supply and demand by accelerating local new gas field development and expanding its gas infrastructure including natural gas pipelines and LNG plants. One option for enhancing natural gas supply is the so-called the South Sumatra Nature Gas Pipeline Project. KOGAS and PDPDE (hereafter referred to as a KOGAS-PDPDE), an Indonesian incorporated entity, are seeking to generate revenues through gas transportation, which is classified as a downstream activity under Indonesia's regulation of Energy Law. Indonesia's oil and gas sector is governed by Law No.22 of 2001 that differentiates upstream business activities from downstream activities. Controlled by SKK MIGAS (Special Task Force for Upstream Oil and Gas Business Activities), upstream business activities include exploration and exploitation. Downstream activities, such as processing, transmission, distribution, storage, and trading, fall under Government Regulation No.36/2004 as last amended by No.30/2009 [11].

The Downstream Oil and Gas Regulatory Agency, BPH MIGAS, is responsible for regulating, developing and supervising downstream activities. Downstream businesses are required to operate through an Indonesian incorporated entity, which must acquire a business license issued by the Ministry of Energy and Mineral Resource (MEMR) with an advice from BPH MIGAS [9]. Therefore, to operate KOGAS-PDPDE entity must acquire a transportation license that will be issued via two stages [9]. There is a temporary license for a maximum period of five years during which an Indonesian incorporated entity prepares the facilities and infrastructure of the business. A permanent operating license can be granted, once an Indonesian incorporated entity is ready for operation. KOGAS-PDPDE must also obtain Special Rights from MEMR in order to transport gas by pipeline within the stipulated transmission and distribution routes [12].

The transportation business license must comply with a national gas transmission and distribution network master plan. It also has to provide an opportunity for other parties to share pipelines and other facilities used for gas transportation known as the open access policy [9]. The Indonesian government has adopted an open access policy for storage and distribution facilities of oil based fuels and natural gas to increase domestic demand of natural gas, increase usage of natural gas transportation facilities, and guarantee a fair opportunity to all gas traders [13]. The open access policy, based on the Oil and Gas Law No.22/2001 and Government Regulation No.36/2004, might affect the South Sumatra Natural Gas Pipeline Project, as it can be connected with an existing gas pipeline in south Palembang, and third parties can tie gas pipelines to the KOGAS-PDPDE pipelines. Under Indonesian law, BPH MIGAS is also responsible for determination of natural gas pipeline transmission and prices, so KOGAS-PDPDE is required to negotiate transmission tariffs and prices with BPH MIGAS [9].

Next chapter accounts for the introduction and importance of the South Sumatra Natural Gas Pipeline Project to contribute to enhance Indonesia natural gas supply under the open access policy. It also describes how to create revenues from a transportation business under the supervision of BPH MIGAS.

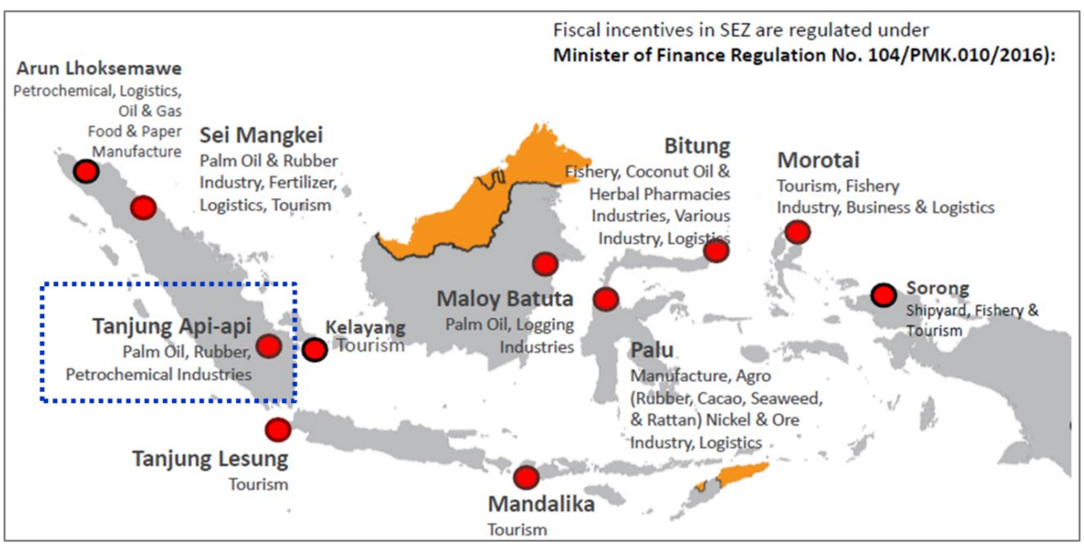
Chapter 3: The Introduction of the South Sumatra Natural Gas Pipeline Project

3.1 Background of the Project

In 2014, the President of the Republic of Indonesia designated Tanjung Api-Api (TAA) as a Special Economic Zone (SEZ) in accordance with the Government Regulation of No. 51/2014 [14]. It is one of eleven SEZs in Indonesia and the only one in South Sumatra. An Indonesia SEZ is a region within a province that has a special authority to access global markets. The SEZs are open to foreign investment and offer investors access to preferential regulatory infrastructure and taxation in an attempt to channel investment into specific locations [15].

The SEZs seek to increase the economic potential of industrial activities as well as material export and import. Tanjung Api-Api SEZ is located in Bayuasin district, which is 80 km from the city of Palembang of South Sumatra (see Fig. 3).

Figure 3: Special Economic Zones in Indonesia



(Source: based on the figure in page 24 from [16])

Sudirman, Indonesia's Minister of Energy and Mineral Resources, has described the TAA as follows: "Tanjung Api-Api will have an integrated energy industry from upstream to downstream sector including coal gasification, coal liquefaction, power plant, fertilizer factory, cement factory, tire factory, CPO processing facility, oil refinery, and petrochemical downstream industry [17]." Table 3 lists some of the TAA SEZ investment opportunities.

Table 3: Investment Opportunity in Tanjung Api-Api

Logistics Zone	**Industrial Zone**	**Energy Zone**
Warehousing	Palm Oil Industry	Petrochemicals
Trade Center	Rubber Industry	Oil Refinery
Open Storage Yard	Pulp and Paper Industry	Coal
Fuel Station	Wood and Cork Industry	Power Plants
Clean Water Treatment Plant	Food Processing Industry	
Waste Water Treatment Plant	Cement Industry	
Public Transport Station	Fertilizer Industry	
	Small and Medium Industry	

(Source: Republic of Indonesia National Council for Special Economic Zone, 2018, Investment Opportunity in Tanjung Api-Api, http://kek.go.id/tanjung-api-api, examined 25 Jul. 2018)

The expected growth in urbanization and industrialization that Sudirman predicts would create significant energy demand within the TAA SEZ. To meet the regional energy demand market, KOGAS and Perusahaan Daerah Pertambangan dan Energi (PDPDE), a South Sumatra-owned company, signed a memorandum of understanding (MOU) in 2016 to conduct a feasibility study and to assign participant's roles for implementing the South Sumatra Natural Gas Pipeline Project [18].

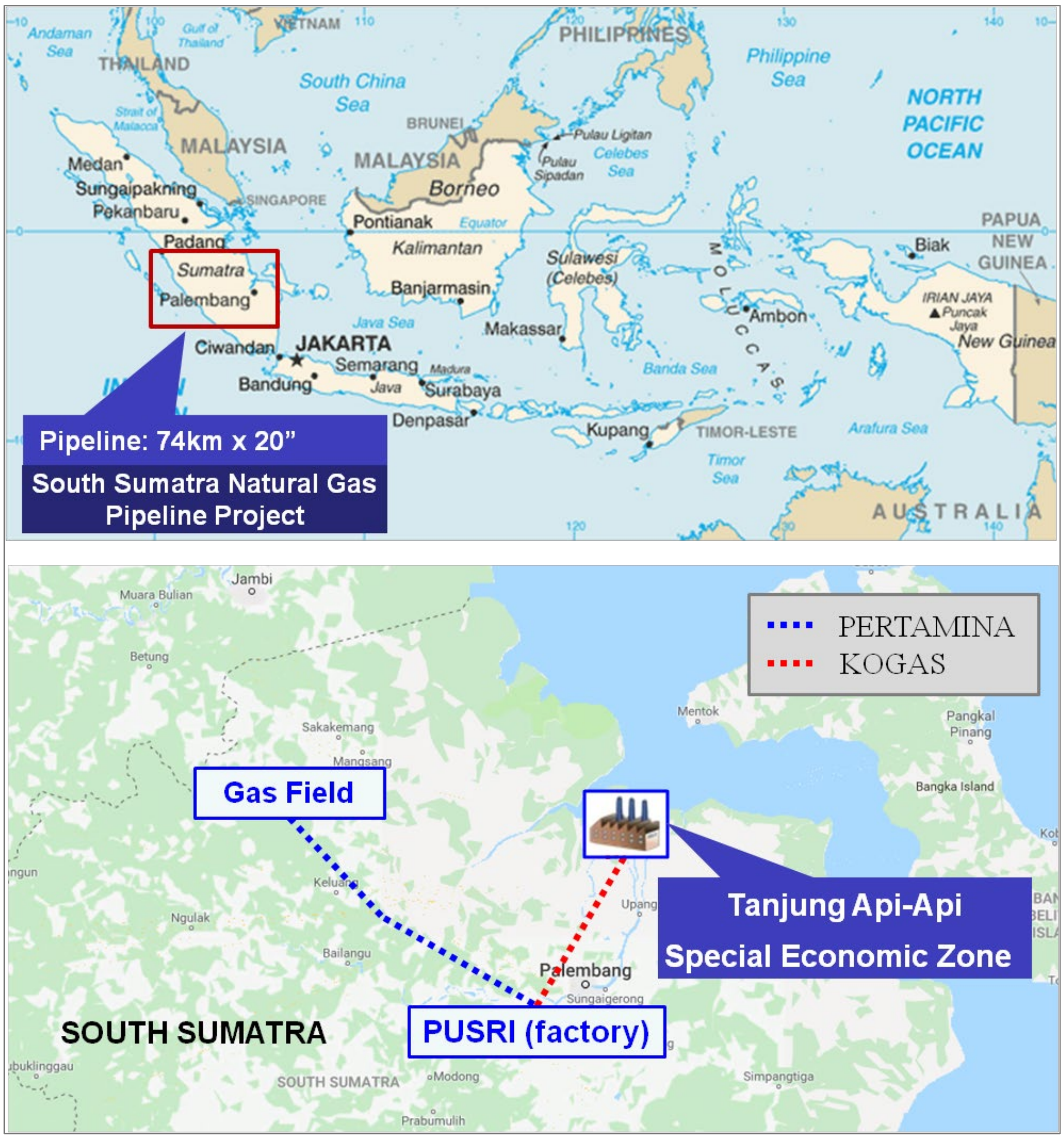
The project plans to build a 74 km long gas pipeline with a diameter of 20 inches from PT Pupuk Sriwidjaja Palembang (Pusri) plant in Palembang city to TAA SEZ (see Fig. 4). The pipeline will tap into an existing natural gas pipeline, which has a diameter of 20 inches and stretches 176 km from the ConocoPhillips' gas plant in Grissik to a Pusri plant in Palembang City to supply gas for energy and raw materials. As a national fertilizer producer, Pusri has engaged its business operation with the main purpose to perform and support the government's policies and programs in the economic and national development sector in fertilizer and agriculture industries.

As of 2018, however, the South Sumatra Natural Gas Pipeline Project is pending due to an uncertain gas demand, the delay of development of TAA SEZ, and the current master plan which includes a coal-fired power plant. If BPH MIGAS does not change its master plan to a natural gas-fired power plant from coal-fired power plant, KOGAS will lose the opportunity to participate in the South Sumatra Natural Gas Pipeline Project. It is a crucial risk and major obstacle to investments for a feasibility study and FEED.

A gas-fired power plant might be more beneficial than coal in the long-term. Natural gas is a cleaner-burning hydrocarbon, producing around half the greenhouse gas emissions and less than one-tenth of the air pollutants that coal does when burned to produce electricity, and it reduces carbon dioxide emissions over the long-term [19]. A natural gas-fired power plant may have reduced capital costs and fuel costs with favorable heat rates [20]. A coal-fired power plant might have a lower levelized cost of electricity (LCOE) in the short-term. But, building a gas-fired power plant would fit into a global effort to reduce long-term carbon dioxide emissions. KOGAS could capitalize on existing infrastructure to mitigate costs, as a gas pipeline will tap into an existing natural gas pipeline. In 2018, PT Pertamina gas (Pertagas), the owner of the existing gas pipeline, has begun to supply natural gas [21]. The prospect of cooperation between KOGAS and

PDPDE might persuade the State of South Sumatra and central government of Indonesia to change their master plan.

Figure 4: Maps of the South Sumatra Natural Gas Pipeline Project



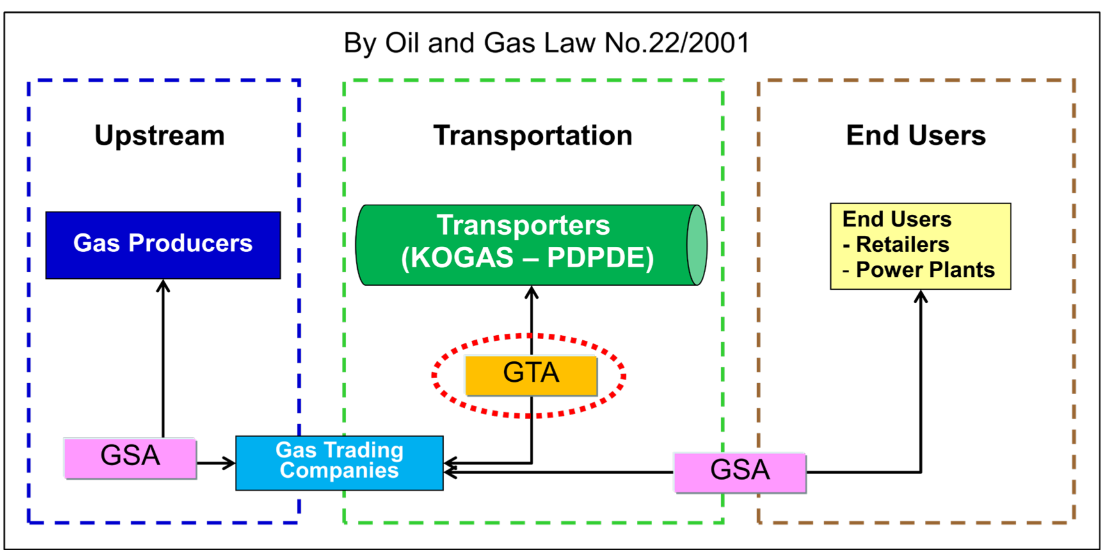
(Source: developed by Kim, D.H.)

3.2 Revenues through Transportation Business

According to unbundling system under the Oil and Gas Law No.22/2001, upstream entities are prohibited from engaging in downstream activities such as transportation and gas trading, and vice versa [9]. The unbundling system prevents a holder of a transportation business license to simultaneously engage in gas trading through pipelines in downstream activities [22]. Affiliated entity may establish a related trading operation based on a separate trading business license [22].

KOGAS has planned to engage only in gas transmission, which will bring revenues from transportation activities by transmitting natural gas via their pipelines (see Fig. 5). Any potential end users, including retailers and power plants, would sign Gas Sales and Supply Agreements (GSA) with gas trading companies that have GSA as well with gas producers to secure gas supplies. The trading companies would sign Gas Transportation Agreements (GTA) with the KOGAS-PDPDE to supply contractual end users.

Figure 5: Gas Business System in Indonesia



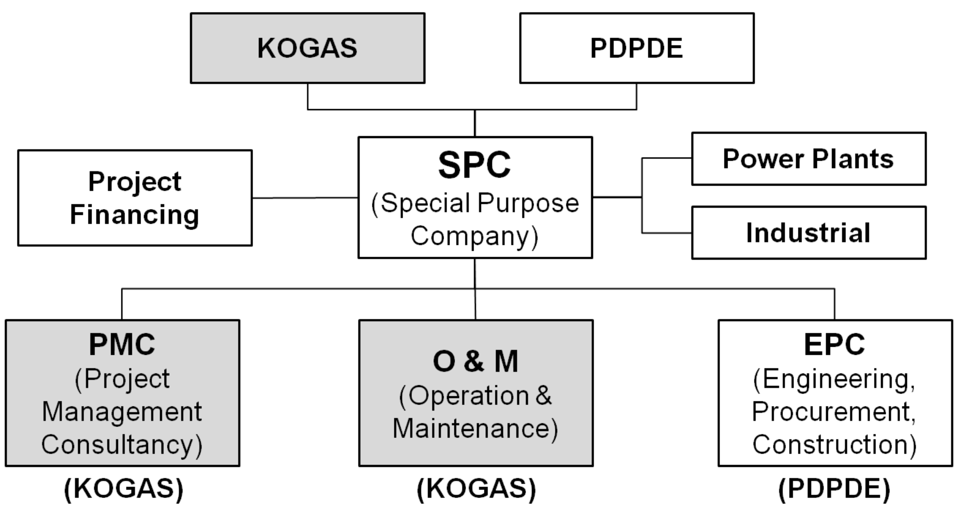
(Source: developed by Kim, D.H.)

As mentioned in Chapter 2, BPH MIGAS has the authority to decide and supervise tariffs for natural gas pipeline transmission. The pipeline operator, KOGAS-PDPDE, has to submit a proposed tariff to BPH MIGAS, which will evaluate the proposed tariffs by discussing with the related parties before determining the tariff [12]. Parties would have to agree on the terms of the GTAs, subject to BPH MIGAS' authority to set tariffs for natural gas pipeline transmission [12].

3.3 Roles of KOGAS for the Project

The South Sumatra Natural Gas Pipeline Project would create a special purpose company (SPC) or a joint venture (JV) composed of KOGAS and PDPDE. During the construction period, KOGAS will be responsible for a project management consultancy (PMC) to secure the project's quality (see Fig. 6). PDPDE will perform engineering, procurement, and construction (EPC) under the signed MOU.

Figure 6: Anticipated Roles of Participants



(Source: developed by Kim, D.H.)

KOGAS has a competitive advantage in operation and maintenance fields of gas pipeline network. For 35 years, KOGAS has constructed and operated a Korean nationwide natural gas pipeline network, with 4,790 km (2,980 mile) transmission pipeline and related facilities. To strengthen the safety, KOGAS implemented in 1997 a proprietary Environment, Health, Safety and Quality (EHSQ) management system for integrated and efficient management. This EHSQ system has contributed to stable and safe operation since 1997 [23]. The stable and safe operations should be reflected in the PMC during construction.

An assignment of participant's roles during construction and operation periods is an important factor for the successful project according to the signed MOU. However, this research might pay attention to an economic viability because the volume of gas demand provides a reason for a feasibility study and FEED. Chapter 4 estimates the potential gas demand and analyzes a sustainability of thirty-year operation from gas fields to secure a viability of the South Sumatra Natural Gas Pipeline Project.

Chapter 4: Gas Demand and Supply Analysis

This chapter develops a method to forecast gas demands and assess the availability of gas supply for electricity generation and industrial feedstock. Maximum gas demand may be limited by the South Sumatra Natural Gas Pipeline transmission capacity relative to the existing Grissik-Pusri pipeline. The supply analysis relates to the sustainability of thirty-year operation from gas fields.

4.1 Gas Demand for Tanjung Api-Api (TAA) Special Economic Zone (SEZ)

4.1.1 Maximum Gas Demand for Electricity

Indonesia has designated Tanjung Api Api (TAA) as a Special Economic Zone (SEZ) to integrate its energy industry, power plants, fertilizer and cement factories, as well as oil and petrochemical industry under the Government Regulation of No. 51/2014 [14]. According to TAA SEZ master plan, maximum TAA SEZ electricity demand will be 753,878 kilo-volt-amperes (KVA), roughly 603 megawatt (MW) as shown in Table 4 [24]. The industry might need approximately 73 percent of total electricity demand. According to the master plan of TAA SEZ, the State of South Sumatra applied a 12 percent loss factor and 0.85 utilization factor to calculate the amount of electricity (State of South Sumatra, 2012). The loss factor is a decrease of electrical potential along the path of a current flowing in an electrical circuit. The utilization factor is the ratio of the time that equipment is in use to the total time.

Table 4: Estimated TAA SEZ Electricity Demand

No	Type	Volume		Standard electricity requirement	Electricity demand (KVA)
		Amount	Unit		
1	Industry	70% of large region	Ha	0.2 MVA/HA	566,243
2	Housing	56,800	Unit	0.45 KVA/Unit	25,560
3	Facilities	1,040.87	Ha	160 KVA/HA	166,538
4	Green Open Space	407.43		40 KVA/HA	16,297
5	Lighting Road (PJU)			10% of household needs	2,556
		Sub total			**777,194**
	Loss factor			12% of the total sub	93,263
	Utilization factor			85% of the total sub	660,615
		Total Electricity Needs			**753,878**

(Source: Table 3.9 from [24])

If the electricity load is fueled by natural gas, the gas volume to meet the electricity demand 603 MW can be computed by Equation 4-1. The equation divides a required energy unit of electricity by heat content. Heat content is an amount of energy released as heat when a volume of natural gas is burned.

$$\text{Natural gas volume} = \frac{\text{electricity demand} \times 24 \text{ hours} \times \text{Heat rate} \times \text{Capacity factor}}{\text{Heat content}} \quad \text{(Eq. 4-1)}$$

One measure of power plant efficiency is the rate that a fuel can be converted into heat and electricity. A heat rate is an amount of energy used by an electrical generator or power plant to generate one kilowatt hour (KWH) of electricity. Two distinct types of technologies, combined cycle and simple cycle, can convert natural gas into electricity. A combined cycle system converting 7,340 BTU per KWH at an average heat rate is more efficient than a simple cycle with a heat rate of 9,788 BTU per KWH [25]. Equation 4-1 assumes a combined cycle system and uses a heat rate of 7,340 BTU per KWH to calculate a volume of the required natural gas.

The heat content is the amount of energy released when a volume of natural gas is burned. The heat content of the natural gas for the South Sumatra Gas Natural Pipeline Project has been estimated as 1,020 BTU per cubic feet (CF) [26].

A capacity factor is how intensively a fleet of generator could run [27]. If a fleet's actual generation compared to its maximum potential generation is near 100 percent, it means that a fleet is operating nearly all of the time [27]. Indonesia's average capacity factor was 66 percent, with an average operational time of 5,800 hours a year in 2010 from all energy resources [28]. According to the report, natural gas had a highest capacity factor with 76 percent, followed by coal, oil, hydro, and geothermal.

Table 5 lists variables to calculate the natural gas volume to meet an electricity demand of 603 MW. From Equation 4-1, the required gas volume to meet the maximum electricity demand is 79.1 million standard cubic feet per day (MMSCFD) (see Equation 4-2).

Table 5: Variables for the Natural Gas Volume

Factors	Values	Factors	Values
Electricity demand	603 (MW)	Heat content	1,020 (BTU/CF)
Heat rate	7,340 (BTU/KWH)	Capacity factor	0.76

(Source: developed by Kim, D.H.)

$$\text{Natural gas volume} = \frac{603(\text{MW}) \times 24(\text{hr}) \times 7{,}340(\text{BTU/KWH}) \times 0.76}{1{,}020\ (\text{BTU/CF})} = 79.1\ \text{MMSCFD} \quad \text{(Eq. 4-2)}$$

4.1.2 Maximum Gas Demand for Industrial as a Feedstock

TAA SEZ fertilizer, cement, paper, and rubber industries can also use natural gas as a feedstock and fuel. Table 6 lists the amount of expected production by industry types. These amounts of production can be converted into natural gas demand using a rate of energy efficiency, which represents the energy requirement to produce one metric ton (1,000 kilograms) of fertilizer, cement, paper, and rubber finished products.

Table 6: The Expected Production

Industry type	Maximum production
Fertilizer Industry	2,260,000 tonne/year
Cement Industry	10,000,000 tonne/year
Pulp/Paper Industry	2,000,000 tonne/year

(Source: Table 4.12 from [29])

Natural gas is a preferred feedstock for fertilizer production due to its high hydrogen to carbon ratio (CH_4). Hydrogen is used for production of ammonia, and thereafter, urea is manufactured with the reaction of ammonia (Parikh *et al.*, 2009). On the assumption that all the urea production units will be operating on natural gas feedstock only, an average energy efficiency of natural gas would be 23.73 gigajoule per tonne (GJ/tonne) of urea [30]. This thesis assumes 23.73 GJ/tonne to estimate the required volume of natural gas as a fertilizer feedstock.

Conventional fossil fuels, such as bituminous coal and lignite, are commonly used in cement production. These fuels produce relatively high volumes of carbon dioxide (CO_2) emissions [31]. One way to somewhat reduce CO_2 emissions is to substitute solid fuels with other fuels with a lower rate of emissions [31]. The best option is natural gas. A cement making process consists of raw material preparation (limestone and fuels), clinker making (fuel use and electricity use), additives preparation, and cement grinding [32]. While the raw material is mostly limestone, natural gas can be utilized for the process of clinker making. Clinker production requires both electricity to run the machinery (as much as 22.5 KWH/tonne) and fuels for drying (as much as 2.85 GJ/tonne) [32]. This thesis assumes 2.85 GJ/tonne to estimate a required natural gas as a feedstock of cement industry for clinker making.

The pulp and paper industry converts fibrous raw materials, mainly woods, into pulp, paper, and paperboard [32]. The papermaking process includes raw material preparation, pulping (chemical, semi-chemical, mechanical, or waste paper), bleaching, chemical recovery, pulp drying, and papermaking. Pulping and drying are the most energy-consuming processes [32]. Most processes use steam and electricity. Kraft recovery, which describes the inorganic pulping chemicals being recovered for reuse, uses fuel [32]. Natural gas could be used to provide the 1.2 giga joule per a dry tonne (GJ/ADT) of heat in the Kraft recovery process [33].

Equation 4-3 calculates maximum gas demand using anticipated maximum productions and energy efficiency of each industry type.

$$\text{Max. gas demand (MMSCFD)} = \frac{\text{Max. production}\left(\frac{\text{tonne}}{\text{year}}\right) \times \text{Energy efficiency}\left(\frac{\text{GJ}}{\text{tonne}}\right) \times 913\left(\frac{\text{CF}}{\text{GJ}}\right)}{365\left(\frac{\text{day}}{\text{year}}\right) \times 10^6} \qquad \text{(Eq. 4-3)}$$

From Equation 4-3, the maximum natural gas demand for industries in the TAA SEZ would be 211.7 MMSCFD, based on annual maximum production and energy efficiency for each industry (see Table 7).

Table 7: The Maximum Gas Demands for Industries in the TAA SEZ

Industry type	Energy efficiency	Maximum gas demand (per day)
Fertilizer Industry	23.73 GJ/tonne	134.3 MMSCFD
Cement Industry	2.85 GJ/tonne	71.4 MMSCFD
Pulp/Paper Industry	1.20 GJ/tonne	6.0 MMSCFD
SUM		211.7 MMSCFD

(Source: developed by Kim, D.H.)

4.1.3 Gas Pipeline Capacity Analysis

As estimated above, the maximum gas demand for electricity and industrial use are 79.1 MMSCFD (Eq. 4-2) and 211.7 MMSCFD (Table 7), respectively, with a total maximum gas of 290.8 MMSCFD. One initial question is whether the KOGAS-PDPDE pipeline could deliver 290.8 MMSCFD. The KOGAS-PDPDE pipeline will connect with Grissik-Pusri pipeline with a diameter of 20 inches and 176 km. Pressure to deliver natural gas from gas fields and the end point of Grissik-Pusri could affect KOGAS-PDPDE's pipeline flow rate capacity.

Under Indonesian law, a pipeline operator is not required to expand its capacity to accommodate new customers, even though facility sharing is obligated by Government Regulation No.36/2004 [12]. Sharing can occur if a facility has sufficient capacity to avoid damages to the facility's owner [12], so an assessment of the capacity of the flow rate for KOGAS-PDPDE's pipeline ought to analyze the outlet pressure of the Grissik-Pusri pipeline. The outlet pressure or gas flow rate can be calculated by Equation 4-4, the Panhandle B equation, a widely used equation for long-line transmission pipeline [34]. The Panhandle B equation is as follows [35].

$$Q_b = 737 \times \left(\frac{T_b}{P_b}\right)^{1.020} \times D^{2.53} \times E \times \left[\frac{P_1{}^2 - P_2{}^2 - \frac{(0.0375 \times G \times (h_2 - h_1) \times P_{avg}^2}{T_{avg} \times Z_{avg}}}{G^{0.961} \times L \times T_{avg} \times Z_{avg}}\right]^{0.51} \quad \text{(Eq. 4-4)}$$

where Q_b is flow rate measured in standard cubic feet per day (SCFD); P_b is base pressure measured in pounds per square inch (PSI); T_b is base temperature measured in °R; T_{avg} is average gas temperature measured in °R; P_1 is inlet pressure measured in PSI; P_2 is outlet pressure measured in PSI; G is gas specific gravity (air = 1.0); L is line length measured in miles; Z is average gas compressibility; D is pipe inside diameter measured in inch; h_2 is elevation at terminus of line measured in ft; h_1 is elevation at origin of line measured in ft; P_{avg} is average line pressure measured in PSI; and E is efficiency factor.

A Grissik-Pusri pipeline outlet pressure using known flow rate and assumed inlet pressure from gas fields via Equation 4-4 yields approximately 830 PSI, using variables listed in Table 8. The flow rate used 70 MMSCFD according to Pertagas' announcement. Grissik-Pusri's volume of gas supply is 30 MMSCFD in the first stage, which can be gradually increased to 70 MMSCFD in the pipeline between Grissik to Pusri [21]. This thesis assumes that h_2, the elevation at terminus of line, is the same as h_1, the elevation at origin of line.

Table 8: Variables for the Outlet Pressure (P_2) of the Grissik-Pusri Pipeline

Variable	Value	Variable	Value
Q	70 MMSCFD	G	0.6
P_1	868 psi	L	109 miles
P_b	14.69 psi	Z	0.971
T_b	518.67 °R	D	20 inch
T_{avg}	518.67 °R	E	0.92

(Source: developed by Kim, D.H.)

A second step is to calculate the flow rate of the KOGAS-PDPED pipeline using the estimated outlet pressure of Grissik-Pusri pipeline in the first step. Using Equation 4-4, the estimated flow rate of the KOGAS-PDPDE pipeline would be 257 MMSCFD. Table 9 lists variables used in Equation 4-4. An inlet pressure of KOGAS-PDPDE Pipeline, P_1, is 830 psi calculated in the first step. The thesis assumed that an outlet pressure might be 583 pounds per square inch absolute (PSI), which is the average value between 20 Bar and 60 Bar because gas-fired gas turbines need a fuel gas pressure of 20 bar (= 290 PSI) to 60 bar (= 870 PSI) in Indonesia [36]. This thesis assumes that h_2, the elevation at terminus of line, is the same as h_1, the elevation at origin of line.

Table 9: Variables for the Flow Rate (Q_b) of the KOGAS-PDPDE Pipeline

Variable	Value	Variable	Value
P_1	830 psi	G	0.6
P_2	583 psi	L	46 miles
P_b	14.69 psi	Z	0.971
T_b	518.67 °R	D	20 inch
T_{avg}	518.67 °R	E	0.92

(Source: developed by Kim, D.H.)

KOGAS-PDPDE's pipeline is capable of transmitting natural gas at a maximum rate of 257 MMSCFD, which does not meet the maximum gas demands of electricity and industrial usages (290.8 MMSCFD). To meet maximum gas demand, the installation of a compressor might be an option. A compressor functions to increase the gas flow pressure. However, this thesis does not consider the installation of a compressor due to questions of the economic return on investment and the challenge of land acquisition for compressor facilities. According to a growth rate of gas demand in the future, KOGAS-PDPDE could consider installing a compressor. Without a compressor, the maximum gas demand 290.8 MMSCFD would need to be adjusted to less than 257 MMSCFD, due to the limited flow capacity of the pipeline.

4.1.4 Adjustment of Gas Demands

One way to adjust gas demand due to lack of gas pipeline capacity would be to modify industrial use rather than electricity gas demand. The reason is that the electricity gas demand already considered a capacity factor to estimate the maximum electricity gas demand in Equation 4-1. If this thesis assumes an 80 percent industrial operation rate, the maximum gas demand for industrials can be adjusted to be 169.4 MMSCFD from 211.7 MMSCFD (see Table 10). Electricity usage still stands at 79.1 MMSCFD. The adjusted maximum gas demand represents 248.5 MMSCFD.

Table 10: The Adjusted Maximum Gas Demand to Meet Flow Rate

(Original) maximum gas demand		**(Adjusted) maximum gas demand**	
Electricity	79.1 MMSCFD	Electricity	79.1 MMSCFD
Industrials	211.7 MMSCFD	Industrials	169.4 MMSCFD
Sum	290.8 MMSCFD	Sum	248.5 MMSCFD

(Source: developed by Kim, D.H.)

One way to estimate the volume of gas to meet a total gas demand for thirty years is to assume three options for gas supply from 2022 to 2051 based on different demand growth rates (see Table 11). Scenario 1 applies 5.1 percent growth rate, which is the same rate as Indonesia's GDP growth in 2017 [37]. All three scenarios have the same initial gas demand which is 10 percent of maximum gas demands. The initial gas demand of electricity and industrials stands at 8.0 MMSCFD and 21.1 MMSCFD, respectively.

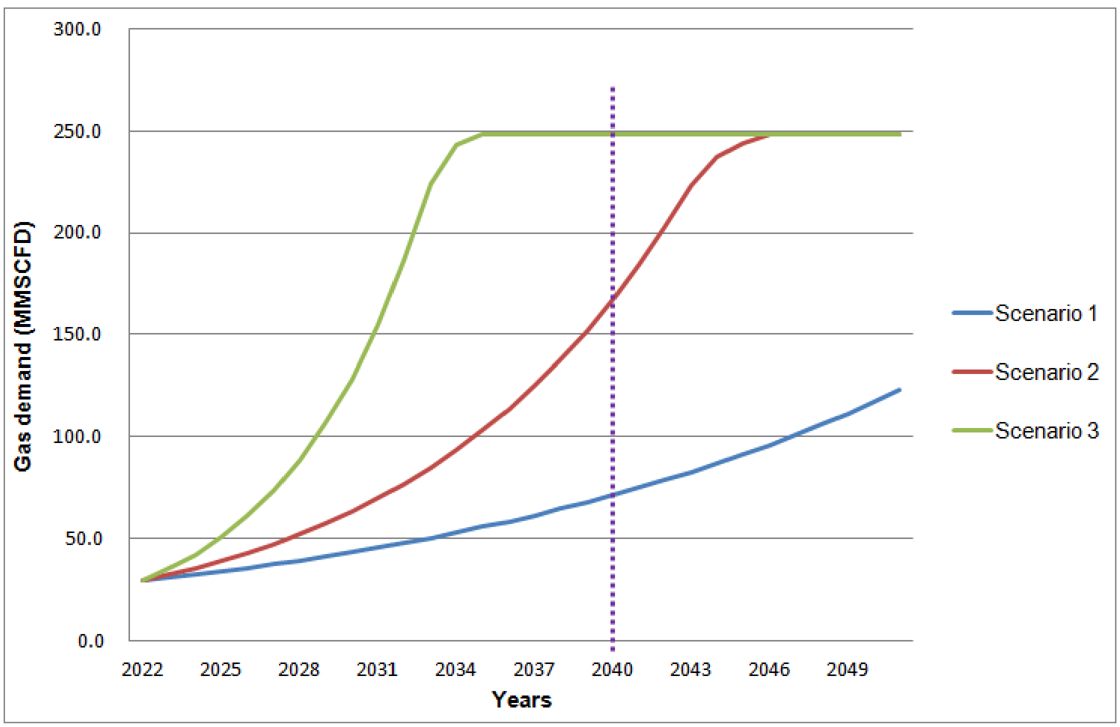
Table 11: Scenarios for Total Gas Demands for 30 Years

No.	**Electricity (MMSCFD)**			**Industrials (MMSCFD)**			**Accumulated total demand (30 years)**
	Initial demand (2022)	Peak demand (year)	Growth rate	Initial demand (2022)	Peak demand (year)	Growth rate	
Scenario 1	8.0	33.9 (2051)	5.1%	21.1	89.3 (2051)	5.1%	718 BCF
Scenario 2	8.0	79.1 (2046)	10.2%	21.1	169.4 (2044)	10.2%	1,498 BCF
Scenario 3	8.0	79.1 (2035)	20.4%	21.1	169.4 (2034)	20.4%	2,062 BCF

(Source: developed by Kim, D.H.)

With respect to the growth rate and initial gas demand, Figure 7 illustrates the annual gas demand of each scenario. While the peak demand in Scenario 2 and Scenario 3 occurs around 2044 and 2034 respectively, a peak demand in scenario 1 reaches only approximately 50 percent of the maximum gas demand even in 2051. For example, in 2040, scenario 3 reaches a peak with 248.5 MMSCFD while Scenario 1 and Scenario 2 account for 71.2 MMSCFD and 167.2 MMSCFD, respectively. The total gas demands for 30 years of Scenario 1, 2, and 3 represent 718 billion cubic feet (BCF), 1498 BCF, and 2062 BCF, respectively.

Figure 7: The Annual Gas Demand by Scenarios



(Source: developed by Kim, D.H.)

4.2 Supply Analysis

Supply analysis can evaluate the availability of gas from gas fields to assure sufficient reserve for gas transmission if KOGAS-PDPDE would sign long-term supply contracts. Even though KOGAS-PDPDE will not be responsible for gas sales agreements (GSA) between gas producer and end users, ensuring sufficient gas volume is an important factor in the transportation business, which creates revenues per unit of gas transported as US dollars per million British thermal unit (USD/MMBTU) from transportation activities by transmitting natural gas via pipelines.

The natural gas for the South Sumatra Pipeline Project can be provided by two gas fields including those in the Corridor Block PSC operated by ConocoPhillips and Jambi Merang operated by Pertamina hulu energi. The KOGAS-PDPDE gas pipeline can connect with Grissik-Pusri gas pipeline with an entry point of the Corridor PSC in Grissik. The Jambi Merang gas field could connect a pipeline to the Grissik entry point.

4.2.1 Corridor Block PSC

Located in South Sumatra, the Corridor PSC has been supplying gas from the Grissik and Suban processing plants to the Duri Steamflood project in Central Sumatra and markets in Java and Batam islands as well as Singapore [26]. The Corridor PSC started gas sales in 1998 and will expire in 2023. Its terms for license extension remain uncertain [26]. ConocoPhillips has shown interest in renewing their production sharing contract (PSC) in the Corridor Block, but has not yet submitted a formal proposal [38].

Sales gas production from the Corridor PSC peaked at 945 MMSCFD in 2014 and has been gradually decreasing since 2014 [26]. Table 12 lists an amount of natural gas production from the Corridor PSC according to long-term supply contracts from 2018 to

2023. The production is decreasing from 854 MMSCFD in 2018 to 699 MMSCFD in 2023. As of 2018, the total production for gas sales until 2023 will represent 4,721 MMSCFD, which is equivalent to 1,723 BCF.

Table 12: Production of the Corridor PSC from 2018 to 2023

Year	2018	2019	2020	2021	2022	2023	Sum
CPI	149	131	113	119	103	93	708
Java	405	367	347	345	342	342	2,148
Singapore	203	213	201	164	149	114	1,044
Batam	65	9	-	-	-	-	74
Other Sumatra	29	52	52	52	52	50	287
Pusri	-	18	45	45	45	45	198
Dumai	4	40	55	55	55	55	264
Sum	854	830	813	780	745	699	4,721

* Unit: MMSCFD
(Source: based on the table in page 14 from [26])

In addition to 4,721 MMSCFD, an available gas reserve from the Corridor PSC might consider potential gas supply contracts since 2023. Either ConocoPhillips or a new owner might sign gas supply contracts for post-2023. Wood Mackenzie anticipates a potential production profile since 2023 [26] (see Table 13). The total production for potential gas sales from 2024 to 2033 represents 2,185 MMSCFD, which is 798 BCF. Therefore, the total gas sales represent 2,521 BCF from the sum of 1,723 BCF and 798 BCF.

Table 13: Production of the Corridor PSC since 2023

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Sum
Sales gas	483	398	319	249	199	163	127	99	81	67	2,185

* Unit: MMSCFD
(Source: based on the table in page 15 from [26])

4.2.2 Jambi Merang Block

Jambi Merang Block is an onshore block located in South Sumatra that has produced gas since 1998. The current Jambi Merang joint operating agreement (JOA) will expire in 2019 [39]. Additional gas resources exist in the block and the operator is evaluating further expansion plans. Due to the potential expiration of a JOA, further gas development or sales would require a license extension [39].

The annual sales gas production from the Jambi Merang Block peaked at 118 MMSCFD in 2013 and has been decreasing gradually since 2014 [39]. As of 2018, the total production for gas sales until the expiry represents 103 MMSCFD, which equivalent to 37 BCF [39].

4.2.3 Available Gas Resource for the South Sumatra Natural Gas Pipeline Project

The available gas resource for the South Sumatra Natural Gas Pipeline Project can be estimated by deducting signed or anticipated sales gas from current gas reserves. Table 14 represents remaining gas reserves and gas production for sales from Corridor PSC and Jambi Merang Block. According to the Ministry of Energy and Mineral Resources of Indonesia, in 2014, the remaining 1P gas reserves for Jambi Merang Block represent 590 BCF and the Corridor PSC amounts to 4,785 BCF, which totals 5,375 BCF [40]. This gas supply analysis considers only proved gas reserves, otherwise known as 1P gas reserves, which means that the reserve can be extracted with 90 percent certainty.

The available gas for the South Sumatra Natural Gas Pipeline Project is 1,396 BCF from the sum of 979 BCF and 417 BCF as shown in Table 14. Considering the past production (2014-2017) and planned production (2018-2023) (see Tables 12 and 13), the potential remained reserve of natural gas would be 979 BCF and 417 BCF from Corridor PSC and Jambi Merang, respectively.

Table 14: The Result of the Supply Analysis

Category		**Corridor PSC**	**Jambi Merang**	**Remark**
Remaining gas reserve (as of Jan, 2014)		4,785 BCF	590 BCF	(1)
Production (2014-2017)		1,285 BCF	136 BCF	(2)
Production (2018-2023)		1,723 BCF	37 BCF	(3)
Production (post-2023)		798 BCF	-	(4)
Available gas for the project		979 BCF	417 BCF	(1) – (2+3+4)
Sum of available gas		1,396 BCF		Corridor PSC + Jambi Merang
Gas demand	Scenario 1	718 BCF		Satisfied
	Scenario 2	1,498 BCF		Not satisfied
	Scenario 3	2,062 BCF		Not satisfied

(Source: developed by Kim, D.H.)

Table 14 also shows whether available gas could meet thirty-year gas demand of scenarios for long-term supply contracts. If the available gas is compared to the accumulated gas demands for 30 years per the Table 11 scenarios, the available gas reserve cannot meet the gas demands of both Scenario 2 and Scenario 3, as listed in Table

14. Scenario 2 might require additional 102 BCF gas. Scenario 3 might need extra 666 BCF gas. Insufficient supply of gas and decreasing long-term gas reserves represents a significant risk. If KOGAS cannot secure guaranteed gas reserves for thirty-year supply from other gas fields, the projects might not meet their financial expectations. Prior to taking further steps, KOGAS needs to discuss additional gas-field development plans with PDPDE and the State of South Sumatra. This supply risk will be discussed in Chapter 6, along with other project risks.

The thirty-year potential gas demands including electricity and feedstock estimate revenues based on an assumed toll-fee from a discounted future cash flow. In the next chapter, this thesis performs an economic analysis, which computes the net present value and internal rate of return to evaluate an economic viability of the South Sumatra Natural Gas Pipeline Project.

Chapter 5: Economic Analysis

This chapter estimates the net present value (NPV) and internal rate of return (IRR) for the South Sumatra Natural Gas Pipeline Project to assess its economic viability based on its discounted future cash flow. KOGAS would use these NPV and IRR results to evaluate whether to pursue the South Sumatra Natural Gas Pipeline Project.

A first step is to derive a discount rate to estimate how much the project's future cash flows would be worth in the present. The NPV analysis will discount the future cash flows at the project's weighted average cost of capital (WACC). A second step is to estimate revenues from the potential gas demands, as calculated in chapter 4.1.4 using an assumed toll-fee. A third step is to estimate project costs, including capital expenditures (CAPEX) and operating expenses (OPEX). A fourth step is to perform an economic analysis to calculate the NPV and IRR. A final step is to perform a sensitivity analysis to evaluate risk factors.

5.1 Discount Rate

An appropriate discount rate is a first step for estimating the NPV and IRR from cash flow. KOGAS uses the weighted average cost of capital (WACC) as their discount rate to determine the present value. The WACC is the weighted average of the costs of a firm's choice of financing sources, with each cost weighted according to its source's proportion of total financing as indicated in Equation 5-1. The WACC that will discount the future cash flow of the South Sumatra Natural Gas Pipeline Project is

$$\mathrm{WACC} = k_e w_e + k_d (1 - T) w_d \tag{5-1}$$

The cost of equity (k_e) is the rate of return that shareholder requires for investing equity into a business. The cost of debt (k_d) is the interest rate that a company pays on its borrowing. The value of w_d is the weight attached to debt, and w_e is the weight attached to common equity. The cost of debt financing is the rate of return required by the firm's creditor's, k_d, adjusted downward by a factor equal to 1 minus the corporate tax rate (1-T) to reflect the fact that the firm's interest expense is tax-deductible. Thus, the creditors receive a return equal to k_d, but the firm experiences a net cost of only $k_d(1-T)$.

The cost of equity (k_e) indicated in Equation 5-1 can be estimated by Equation 5-2. The cost of equity generally consists of a risk free rate of return and a market premium assumed for operating a business, but KOGAS also adds a country risk premium. KOGAS' cost of equity is

$$k_e = R_f + \beta_e \cdot RP_m + RP_c \qquad (5\text{-}2)$$

The risk free rate (R_f) should not take into account any risk factors and should only include time value of money and inflation [41]. Beta (β_e) measures how the returns of a certain company behave in relation to the returns of the relevant market benchmark. For example, if a beta is smaller than 1.0, it means the share price of a company is less volatile than general market [41]. The market risk premium (RP_m) is the average return that investors require over the risk-free rate for accepting the higher variability in returns that are common for equity investments [41]. The country risk premium (RP_c) is an additional risk associated with investing in an international company, rather than the domestic market.

Financing a gas pipeline project typically would involve a high ratio of debt. An owner might prefer to limit its equity investment in a project to avoid commercial risks. For the South Sumatra Natural Gas Pipeline Project, KOGAS considers a 60 percent of debt ratio for the project, meaning that the value of w_e and w_d account for 0.4 and 0.6, respectively. As of 2018, Indonesia's corporate tax rate is 25 percent [42], meaning that the T value is 0.25. The United States government bonds are generally used as reference for a risk-free rate. According to U.S. Department of the Treasury, a current 30 year treasury yield as of January 14, 2019 is 3.06 percent, which is the risk-free rate, R_f [43]. β_e represents the sensitivity of the equity returns to variations in the rates of return on the overall market portfolio [44]. KOGAS have used the beta coefficient at 0.5772 referred to a midstream gas business, including a gas pipeline transportation business. The market risk premium applies a value, which is 5.5 percent as of June 30 in 2018, as recommended by KPMG [41]. NYU Stern estimated Indonesia's country risk premium at 2.64 percent as of January 2019 [45]. Therefore, using Equation 5-2, the cost of equity (k_e) is estimated to be 8.87 percent.

The cost of debt is the return that a company provides to its debt holders and creditors. These capital providers expect to be compensated for any risk exposure that comes with lending to a company. The approach to estimate the cost of debt (k_d) is using KOGAS' financial statement through dividing the annual interest by total debt that KOGAS is carrying as indicated in Equation 5-3.

$$k_d = \frac{\text{Total interest of KOGAS}}{\text{Total debt of KOGAS}} = \frac{736{,}980 \text{ million KRW}}{28{,}519{,}097 \text{ million KRW}} = 2.58\ \% \qquad (5\text{-}3)$$

On the KOGAS' balance sheet of 2018, total amount of debt was 28,519,097 million Korean won (KRW) [46]. The total interest KOGAS paid in 2018 was 736,980 million KRW on the income statement of 2018 [47]. The cost of debt (k_d) is 2.58 percent.

A WACC value is equal to 4.71 percent in Equation 5-1. This WACC value will be used as the discount rate to calculate the NPV in the cash flow analysis.

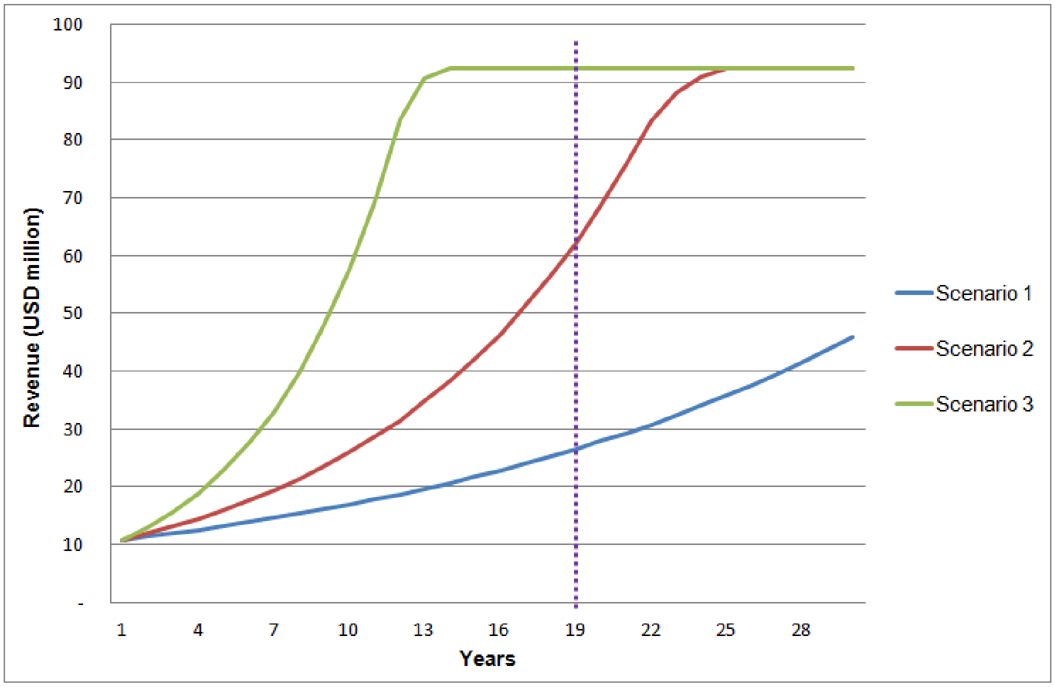
5.2 REVENUES

The South Sumatra Natural Gas Pipeline Project transmits natural gas via their pipelines to create revenues measured in USD/MMBTU. BPH MIGAS has controlled gas transportation businesses under Government Regulation No.36/2004 and MEMR Regulation No.19/2009 [11]. BPH MIGAS have determined a gas pipeline toll-fee (tariff) under Regulation No.16/2008 as last amended by No.8/2013 [9].

According to the BPH MIGAS' regulation (2013), there are three kinds of toll-fee systems: (a) one toll rate at any delivery point of the pipeline, regardless of a distance; (b) different toll-fees, depending on the transmitting distance; and (c) entry-exit system which charges a toll-fee at entry point or exit point as shippers are different at the both points [48]. The South Sumatra Natural Gas Pipeline Project assumes to set the toll-fee at 1.00 (USD/MMBTU) throughout the entire thirty years of project duration for the economic analysis [18].

Based on the potential demand of Table 11, Fig.8 illustrates expected future revenues. The revenue trend for scenarios is the same as the potential gas volume trend of Fig. 7 because the applied toll-fee is 1.00 USD/MMBTU. For example, in 2040, which is 19th-operation year, Scenario 3 reaches a peak with 92 million USD while Scenario 1 and Scenario 2 represent 26 million USD and 62 million USD, respectively. Accumulated total revenues of each scenario for thirty-year operation account for 732 million USD at Scenario 1; 1,528 million USD at Scenario 2; and 2,103 million USD at Scenario 3.

Figure 8: The Annual Revenue by Scenarios



(Source: developed by Kim, D.H.)

5.3 Project Costs

Costs for the South Sumatra Natural Gas Pipeline Project include both capital expenditures (CAPEX) and operating expenses (OPEX). CAPEX accounts for all initial costs required to construct all facilities such as planning, feasibility studies, engineering design, land acquisition, construction, and inspection and testing before an operation. OPEX refers to operation and maintenance costs over the project life cycle.

Pipeline project costs are influenced by a location, terrain, labor cost, or market price of components such as steel. Safety issues, environmental issues, legal and political arguments, and the installation process for a pipeline installation also affect total project cost [49]. Due to many factors, it is difficult to anticipate all project costs or be able to create a global average unit cost for a pipeline project. Front end engineering design (FEED) after a conceptual design or feasibility study can estimate approximate investment costs, even with substantial risks and uncertainties. One way to estimate the South Sumatra Pipeline Project cost is to consider historical gas pipeline projects in Indonesia or obtain cost estimates or bids from several Indonesian EPC companies. However, there are limited historical data references. Any cost estimates might be unreliable without FEED. Another way to anticipate the project cost is to analyze recent tenders from BPH MIGAS to compare unit costs. It is complicated to derive unit cost for an on-shore pipeline because most recent tenders are associated with off-shore pipeline projects.

To estimate CAPEX for the South Sumatra Natural Gas Pipeline Project, this thesis analyzes historical pipeline projects in the United States (U.S.) to estimate a unit cost per inch-meter. A first step is to categorize unit cost into four components: materials cost; labor cost; miscellaneous cost; and right of way (ROW) cost. A second step is to estimate multipliers for converting an U.S. unit cost to an Indonesian unit cost for all components to derive a unit cost per inch-meter for the South Sumatra Natural Gas Pipeline Project.

From 1993 to 2007 in the U.S., costs for building natural gas pipeline infrastructure varied between 30,000 USD and 100,000 USD per inch-mile [50]. The large variation between the two values may be due in part to steel prices and regional variations [51]. INGAA have recently applied pipeline cost multipliers to estimate the average pipeline cost of the U.S. in six regions: Southwest, 0.68; Central, 0.69; Midwest, 0.85, Southeast, 1.09; Western, 1.14; and Northeast, 1.46 [51]. In 2012, the average pipeline cost increased drastically to 155,000 USD per inch-mile. This value indicates that historical data before 2007 may not be accurate as a basis of estimating average pipeline CAPEX costs in the U.S. This thesis utilized the recent ten-year historical data provided by Federal Energy Regulatory Commission (FERC). Table 15 lists 10 years of unit onshore CAPEX for natural gas pipeline with diameters ranging from 8 to 36 inches [52]. It lists average cost per mile for any given diameter. Costs fluctuate year to year as project costs are affected by geographic location, terrain, population density, or other factors [52]. For example, an average construction cost of a 12 inch pipeline increased from 1,548,033 USD per mile in 2013 to 10,535,221 USD per mile in 2014. This value, in turn, decreased to 3,951,424 USD per mile in 2015.

Table 15: U.S. Natural Gas Pipeline Onshore Construction Costs for 10 years

10 YEARS OF LAND CONSTRUCTION COSTS[1]

Table 6

Size	Year	ROW	Material	Labor	Misc.	Total	Low	High
		Average cost, $/mile					Range, $/mile	
8 in.	2016	—	—	—	—	—	—	—
	2015	55,289	153,115	603,317	179,045	990,765	766,056	1,273,258
	2014	17,717	608,268	119,685	988,189	[2]1,733,858	—	—
	2013	71,443	188,261	69,541	1,533,654	1,862,899	1,762,637	4,246,500
	2012	—	—	—	—	—	—	—
	2011	—	132,884	917,910	582,952	[2]1,633,746	—	—
	2010	—	—	—	—	—	—	—
	2009	—	—	—	—	—	—	—
	2008	17,438	378,698	199,342	114,617	[2]710,095	—	—
	2007	—	—	—	—	—	—	—
12 in.	2016	68,779	188,942	737,056	438,626	[illegible]	1,278,571	1,579,170
	2015	469,849	278,164	1,837,630	1,365,782	3,951,424	2,900,135	4,928,073
	2014	772,578	721,073	4,777,695	4,263,874	[2]10,535,221	—	—
	2013	64,313	319,004	784,464	380,252	[2]1,548,033	—	—
	2012	75,246	213,859	612,119	419,950	[2]1,321,173	—	—
	2011	—	—	—	—	—	—	—
	2010	—	—	—	—	—	—	—
	2009	—	—	—	—	—	—	—
	2008	178,757	195,406	566,193	466,159	1,406,515	541,392	4,186,636
	2007	—	—	—	—	—	—	—
16 in.	2016	267,288	415,979	1,937,269	1,473,663	[2]4,094,199	—	—
	2015	357,891	380,604	1,395,814	2,180,469	4,314,779	3,175,990	14,996,594
	2014	574,745	483,528	2,911,085	2,807,562	6,776,920	6,471,863	7,325,147
	2013	81,810	286,739	533,749	636,324	1,538,623	1,005,653	5,882,153
	2012	126,033	302,558	748,967	302,760	[2]1,480,318	—	—
	2011	278,231	305,235	1,004,152	1,328,691	2,916,309	2,007,514	3,885,413
	2010	263,135	222,719	885,769	966,447	[2]2,338,069	—	—
	2009	226,517	417,899	1,480,926	586,626	[2]2,711,968	—	—
	2008	421,484	1,182,666	1,689,992	1,552,542	[2]4,646,684	—	—
	2007	—	—	—	—	—	—	—
20 in.	2016	199,333	329,680	2,728,127	1,740,590	4,997,730	4,457,245	5,142,998
	2015	324,055	425,218	985,093	1,689,816	3,424,182	2,476,789	6,049,136
	2014	473,329	632,417	2,264,767	2,142,928	5,513,441	2,723,642	11,975,448
	2013	103,333	338,025	998,560	701,317	[2]2,141,235		
	2012	8,941	275,292	69,647	1,349,884	[2]1,703,765	—	—
	2011	97,553	402,232	1,208,048	816,998	2,524,831	1,773,309	7,970,976
	2010	64,198	1,194,239	1,663,457	1,504,568	[2]4,426,461	—	—
	2009	164,377	820,867	1,993,079	1,061,331	4,039,654	3,866,474	7,528,043
	2008	23,219	869,178	941,096	491932	[2]2,325,425	—	—
	2007	—	—	—	—	—	—	—
24 in.	2016	134,000	337,650	2,021,810	836,247	[2]3,329,707	—	—
	2015	157,746	633,298	1,930,386	1,006,423	3,727,853	1,877,375	9,056,833
	2014	231,155	523,863	1,516,691	1,075,740	3,347,449	1,469,338	6,181,322
	2013	73,560	623,116	805,886	912,622	2,415,184	1,922,659	4,681,258
	2012	181,741	701,303	1,910,324	1,143,928	3,937,296	2,254,386	4,481,436
	2011	283,312	409,840	1,603,609	1,482,417	3,779,177	1,873,984	11,877,953
	2010	—	—	—	—	—	—	—
	2009	65,567	530,093	1,085,736	663,240	2,344,636	1,975,000	3,399,653
	2008	—	—	—	—	—	—	—
	2007	25,467	351,083	324,023	453,737	1,155,030	830,872	4,301,932
30 in.	2016	736,129	920,316	4,919,086	3,406,645	9,982,176	6,779,317	11,935,160
	2015	658,419	977,539	3,792,172	2,457,962	7,886,092	6,684,118	13,416,935
	2014	268,605	690,850	2,155,315	2,036,710	5,151,482	4,600,017	8,873,792
	2013	—	—	—	—	—	—	—
	2012	290,807	1,020,108	3,218,952	3,242,493	7,772,360	6,356,657	35,732,500
	2011	390,263	745,675	3,648,578	2,276,889	7,061,405	6,384,345	7,177,507
	2010	160,922	769,453	1,601,563	966,007	[2]3,497,944	—	—
	2009	384,467	624,980	912,342	113,283	2,035,073	1,955,746	3,917,264
	2008	83,016	1,091,147	356,539	472,278	2,002,981	1,684,461	2,264,167
	2007	156,303	1,371,819	1,328,831	922,647	3,779,600	1,546,833	4,715,909
36 in.	2016	504,104	895,253	3,301,095	2,763,844	7,464,296	4,408,216	12,488,572
	2015	1,083,005	1,130,531	2,010,998	2,181,621	6,406,155	5,411,030	16,151,288
	2014	—[3]	1,106,103	3,061,029	1,683,401	5,760,613	346,243	5,876,636
	2013	93,529	1,400,946	2,182,912	1,938,652	5,616,040	3,461,864	79,188,232
	2012	—	—	—	—	—	—	—
	2011	519,369	937,500	2,864,358	3,059,234	7,380,462	7,072,552	7,848,259
	2010	107,000	1,641,171	1,544,020	1,051,506	[2]4,343,697	—	—
	2009	499,329	1,083,073	1,084,429	892,446	3,559,276	3,284,505	3,600,324
	2008	170,489	994,375	1,098,096	511,589	2,774,549	2,427,457	9,013,608
	2007	97,746	869,995	628,204	893,293	2,489,238	1,857,468	4,056,369

[1]Estimates; based on FERC construction-permit applications for a 12-month period ending June 30 of each year. [2]Only one project proposed during this period for this diameter. [3]One of the projects of this diameter did not list ROW as a discrete category.

(Source: Table 3 from [52])

For the past ten years, the unit pipeline costs have ranged between 80 USD and 237 USD per inch-meter (3.0 million USD and 9.6 million USD per mile), with a mean value of 159 USD per inch-meter, based on Table 15 (see Table 16). The mean value of 159 USD per inch-meter will be used to estimate average pipeline CAPEX costs.

Table 16: U.S. per Inch-Meter Unit Pipeline Cost for 10 Years

Cost	**Range (per mile)**		**Range (per inch-meter)**	
	Low	High	Low	High
Unit cost	3,018,695 USD	9,654,228 USD	80 USD	237 USD
Mean unit cost	6,336,462 USD		159 USD	

(Source: based on Table 3 from [52])

Information on total unit cost components would be available to derive a reasonable unit cost for construction of the South Sumatra Natural Gas Pipeline Project. The unit cost for natural gas pipelines generally consists of four categories: materials, labor, miscellaneous, and right of way (ROW) [52]. Materials costs include pipe, pipe coating, and cathodic protection. Miscellaneous costs are associated with surveying, engineering, supervision, interest, administration, overhead, contingencies, regulatory fees and allowances for funds used during construction [49].

From historical cost data of 412 pipelines recorded from 1992 to 2008 in the United States, labor cost has the highest share of 40 percent of total cost [53] (see Table 17). Table 17 lists the shares of each components and corresponding total costs. Materials have contributed 30 percent of total cost. Miscellaneous and ROW costs have contributed 23 percent and 7 percent, respectively. The sum of labor and materials cost accounts for up to 70 percent of total cost. These costs can be modified by estimating multipliers from comparisons between the United States and Indonesia.

Table 17: Mean Unit Cost of Each Component by Shares

Mean unit cost (from Table 17)	**Components of total cost**	**Share**	**Cost by share**
159 USD (per inch-meter)	Labor	40%	63.44 USD
	Materials	30%	47.58 USD
	Miscellaneous	23%	36.48 USD
	ROW	7%	11.10 USD

(Source: developed by Kim, D.H.)

Building a pipeline in developing countries can be less expensive than in developed countries due to wage differences [49]. To estimate a labor cost multiplier for the South Sumatra Natural Gas Pipeline Project, this thesis compared a nominal wage of the United States and Indonesia. Table 18 shows an average annual salary of construction labor workers of the United States and Indonesia: 41,361 USD in the U.S. versus 70 million Indonesia Rupiah (IDR) in Indonesia [54]. The estimated multiplier for the labor cost of the South Sumatra Natural Gas Pipeline Project accounts for 0.12 of the US labor cost.

Table 18: Estimation of a Multiplier for the Labor Cost

Country	**Average salary (2019)**	**Currency exchange**	**Ratio**	**Multiplier**
United States	41,361 USD	41,361 USD	100%	1
Indonesia	70,000,000 IDR	4,945 USD	12%	0.12

* 1 USD = 14,285 IDR (as of Jan 24, 2019)

(Source: developed by Kim, D.H.)

The material cost index has a similar trend with the producer price index (PPI) for iron and steel [49]. The material cost index is dependent on steel price because steel represents a majority of the materials cost for a natural gas pipeline project. This thesis estimates the material cost multiplier by analyzing a potential market price of steel in the United States and Indonesia. The analysis builds from the current market price of steel, with a ratio between production and import of steel.

As the world's largest steel importer, the U.S. imported 34.6 million metric tons (MMT) of steel in 2017 [55], and produced 81.6 MMT of steel [56]. Indonesia, the world's tenth-largest steel importer, imported 11.4 MMT of steel in 2017 [57], and produced 7.8 MMT of steel [58]. Table 19 accounts for the ratio of the import to total consumption of steel in the United States and Indonesia. The ratio of steel import is 30 percent and 59 percent, respectively.

Table 19: Ratio of the Import to Total Consumption of Steel in 2017

Country	**Production**	**Import**	**Sum**	**Ratio of import**
United States	81.6 MMT	34.6 MMT	116.2 MMT	30%
Indonesia	7.8 MMT	11.4 MMT	19.2 MMT	59%

(Source: developed by Kim, D.H.)

By applying the import ratio to a current market price of steel, this thesis estimates a multiplier for the material cost for the South Sumatra Natural Gas Pipeline Project (see Table 20). As of January 16, 2019, the steel price is 806 USD per metric ton (MT) in the US market; 503 USD in world export markets; and 461 USD in the China market [59]. As there is no information on Indonesia steel market, this thesis applies the China market price. The estimated multiplier for the material cost of the South Sumatra Natural Gas Pipeline Project is 0.68.

Table 20: Estimation of a Multiplier for the Material Cost

Country	Source	Share	Steel Price (per metric ton)	Weighted Sum	Multiplier
United States	United States	70%	806 USD	716 USD	1
	Import	30%	503 USD		
Indonesia	Indonesia	41%	461 USD	486 USD	0.68
	Import	59%	503 USD		

* Multiplier (0.68) = 486 USD / 716 USD
(Source: developed by Kim, D.H.)

This thesis assumes that the miscellaneous cost can be related to the consumer price index in the United States [49]. The consumer price index (CPI) is a measure of an average change over time in the prices paid by urban consumers for a market basket of consumer goods and services. Because the direct comparison of CPI between the United States and Indonesia might have nothing to do with estimating the miscellaneous index, this thesis instead uses a cost of living index. A cost of living index is not a straightforward alternative to CPI, but CPI is sometimes termed a conditional cost of living index [60]. In 2019, the cost of living indices for the U.S. and Indonesia are 69.91 and 36.24, respectively [61]. Table 21 illustrates that the estimated multiplier for the miscellaneous cost of the South Sumatra Natural Gas Pipeline Project is 0.52.

Table 21: Estimation of a Multiplier for the Miscellaneous Cost

Country	Cost of living index	Multiplier
United States	69.91	1
Indonesia	36.24	0.52

* Multiplier (0.52) = 36.24 / 69.91
(Source: developed by Kim, D.H.)

Right of way (ROW) costs depends on land prices, which include fees set by local government, legal costs, and permit prices [49]. According to research about 412 pipelines in the U.S., the share of ROW cost remains at 7 percent of total cost, regardless of the length or diameter of pipeline [53]. This thesis assumes for a share of ROW cost for the South Sumatra Natural Gas Pipeline Project to be 7 percent of the total cost, which is the same rate as the United States. It means that the higher total CAPEX, the higher ROW cost with a fixed rate of 7 percent.

The unit cost per inch-meter for the South Sumatra Natural Gas Pipeline Project can be estimated to be 63.22 USD per inch-meter by applying estimated multipliers for each component (see Table 22). Labor cost, material cost, miscellaneous, and ROW of unit pipeline CAPEX cost in Indonesia account for 7.58 USD, 32.30 USD, 18.91 USD, and 4.43 USD, respectively. Using the estimated unit cost, 63.22 USD, the total CAPEX for the South Sumatra Natural Gas Pipeline Project with 20 inches and 74 km can be estimated to be 93,560,000 USD.

Table 22: Mean Unit Cost of the South Sumatra Pipeline Project

<table>
<tr><th rowspan="2">Components</th><th colspan="3">United States</th><th rowspan="2">Multiplier</th><th colspan="2">Indonesia</th></tr>
<tr><th>Unit cost (USD)</th><th>Share</th><th>Component cost (USD)</th><th>Component cost (USD)</th><th>Unit cost (USD)</th></tr>
<tr><td>Labor</td><td rowspan="4">159</td><td>40%</td><td>63.44</td><td>0.12</td><td>7.58</td><td rowspan="4">63.22</td></tr>
<tr><td>Materials</td><td>30%</td><td>47.58</td><td>0.68</td><td>32.30</td></tr>
<tr><td>Miscellaneous</td><td>23%</td><td>36.48</td><td>0.52</td><td>18.91</td></tr>
<tr><td>ROW</td><td>7%</td><td>11.10</td><td>0.40</td><td>4.43</td></tr>
</table>

* CAPEX : 63.22 (USD/inch-meter) * 20 (inch) * 74,000 (m) = 93,560,000 USD
(Source: developed by Kim, D.H.)

Operating expenses (OPEX) will vary in part with the number of compressor stations requiring fuels [62]. Compressor fuels represent a majority of operating costs. The analysis assumes that the South Sumatra Natural Gas Pipeline Project will not use a compressor, as mentioned earlier. Thus, the OPEX for the operation and maintenance might depend on the amount of gas supply. This thesis assumes that the unit cost might be 0.2 USD/MMBTU for the OPEX [18]. The annual OPEX might gradually increase as the growth rate of gas demand increases by scenarios.

5.4 Discounted Cash Flow Valuation

The use of discounted cash flow analysis is common to evaluate long-term investments [44]. This discounted cash flow analysis can include the calculation of the net present value (NPV) and internal rate of return (IRR) as well as Monte Carlo simulation and sensitivity analysis.

Using values estimated above such as the discount rate, revenues, CAPEX, and OPEX, it is possible to calculate the net present value (NPV) and internal rate of return (IRR) for the South Sumatra Natural Gas Pipeline Project from cash flows. Table 23 lists factors to calculate NPV and IRR by scenarios. Except the growth rate of gas demand by scenarios of Table 11, other factors are common regardless of scenarios. It assumed that depreciation period is 10 years computed with straight line depreciation, and other factors are from previous chapters as mentioned in remarks.

Table 23: Factors for the Calculation of NPV and IRR

Factors	Values	Remarks
Toll fee	1.00 (USD/MMBTU)	Chapter 5.2
Initial gas demand (Power Plant & Industrial)	29.1 (MMSCFD)	Chapter 4.1.4
Growth rate of gas demand	5.1 (%)	Chapter 4.1.4
CAPEX	93,560,000 (USD)	Chapter 5.3
OPEX	0.20 USD/MMBTU	Chapter 5.3
Depreciable life	10 (years)	Assumption
Depreciation method	Straight line	Assumption
WACC	4.71 (%)	Chapter 5.1
Cost of equity	8.87 (%)	Chapter 5.1
Cost of debt	2.58 (%)	Chapter 5.1
Duration of gas supply	30 (years)	Chapter 5.2
Tax rate	25 (%)	Chapter 5.1

(Source: developed by Kim, D.H.)

Table 24 shows the result of estimated NPV and IRR from cash flows by scenarios. All scenarios have a positive NPV and a project IRR that exceeds 10 percent which is a KOGAS' minimum IRR for an investment. The project IRR means that no debt is necessary for the project. The equity IRR accounts for using debt for the project. The result indicates that the higher the growth rates, the higher IRR and NPV. According to KOGAS's administrative guidelines for an investment, the project IRR must exceed 10 percent to advance to a feasibility study or front end engineering design (FEED). Based on the result in Table 24, KOGAS may advance to a next step for the South Sumatra Natural Gas Pipeline Project.

Table 24: Result of NPV and IRR from Cash Flows

Scenarios	**IRR**		**NPV** (Unit: USD)	
	Project IRR	Equity IRR	Project NPV	Equity NPV
Scenario 1	11%	15%	114,299,000	43,887,000
Scenario 2	16%	21%	286,290,000	121,274,000
Scenario 3	21%	28%	462,692,000	224,140,000

(Source: developed by Kim, D.H.)

For a further analysis of scenarios, this thesis builds a two-dimensional data table between a growth rate of gas demand and WACC. The growth rate varies from 2 percent to 11 percent, and WACC varies from 4 percent to 15 percent (see Table 25). Table 25 shows that the project NPV increases as growth rate of gas demand increases and WACC decreases. While the project NPV is affected by both variables, the project IRR is influenced only by the growth rate of gas demand. Regardless of variations of WACC, the project IRR increases as the growth rate increases. To meet a KOGAS' minimum rate for an investment and have a positive NPV, WACC ought to be less than 9 percent and the growth rate of gas demand is larger than 3 percent as indicated in Table 25.

Table 25: Estimation of Project NPV and Project IRR

Project NPV		Growth rate of gas demand									
		2%	3%	4%	5%	6%	7%	8%	9%	10%	11%
WACC	4%	$64,824	$84,117	$107,139	$134,686	$167,737	$207,481	$255,375	$313,196	$383,113	$467,774
	5%	$46,187	$62,012	$80,806	$103,194	$129,939	$161,968	$200,417	$246,664	$302,393	$369,655
	6%	$30,818	$43,884	$59,327	$77,639	$99,417	$125,389	$156,440	$193,647	$238,322	$292,059
	7%	$18,056	$28,915	$41,687	$56,760	$74,606	$95,795	$121,024	$151,136	$187,156	$230,328
	8%	$7,387	$16,470	$27,101	$39,588	$54,303	$71,698	$92,320	$116,834	$146,044	$180,926
	9%	($1,589)	$6,056	$14,961	$25,371	$37,580	$51,948	$68,907	$88,983	$112,809	$141,152
	10%	($9,191)	($2,714)	$4,792	$13,523	$23,716	$35,657	$49,688	$66,227	$85,774	$108,937
	11%	($15,667)	($10,146)	($3,780)	$3,588	$12,151	$22,134	$33,813	$47,518	$63,649	$82,687
	12%	($21,215)	($16,482)	($11,050)	($4,793)	$2,441	$10,839	$20,617	$32,042	$45,432	$61,169
	13%	($25,995)	($21,914)	($17,252)	($11,908)	($5,757)	$1,347	$9,583	$19,163	$30,341	$43,425
	14%	($30,135)	($26,596)	($22,573)	($17,981)	($12,722)	($6,676)	$301	$8,380	$17,766	$28,705
	15%	($33,739)	($30,652)	($27,161)	($23,194)	($18,672)	($13,497)	($7,552)	($699)	$7,226	$16,424
											(Unit : Thousand dollars)

Project IRR		Growth rate of gas demand									
		2%	3%	4%	5%	6%	7%	8%	9%	10%	11%
WACC	4%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	5%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	6%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	7%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	8%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	9%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	10%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	11%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	12%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	13%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	14%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%
	15%	9%	10%	11%	11%	12%	13%	14%	15%	16%	17%

(Source: developed by Kim, D.H.)

5.5 Monte Carlo Simulation

Table 24 and Table 25 results have limitations because this analysis considers only one or two value drivers, such as the growth rate or WACC, at a time, with other factors held constant. The analysis does not provide information about probabilities associated with exceeding or dropping below the breakeven value drivers. To address these shortcomings, this thesis performs a Monte Carlo simulation by using @RISK software. Monte Carlo simulation provides a tool that can help an analyst evaluate what can happen to an investment's future cash flows and summarize the possibilities in a probability distribution [44].

This thesis performs a Monte Carlo simulation of Scenario 1 because Scenario 1 stays around the KOGAS' hurdle rate of 10 percent. The first step for the Monte Carlo simulation in Scenario 1 is to define a set of hypothetical assumptions for the probability distributions used to describe key value drivers. The analysis defines seven value drivers that underlie the uncertainty in the investment outcome: (1) toll fee; (2) initial gas demand; (3) growth rate of gas demand; (4) CAPEX; (5) OPEX; (6) cost of debt; and (7) tax rate (see Table 26). This thesis uses two alternate distributions, a uniform or a triangular distribution, to value drivers, except for tax rate which applies a discrete distribution. The uniform and triangular distributions are common distributions used to model the uncertainty inherent in an investment [44]. Toll fee and initial gas demand have a uniform distribution with 20 percent ranges from a mean value. Growth rate of gas demand has a triangular distribution which ranges from 2.5 percent to 7.7 percent. Cost of debt ranges between 2.58 percent and 6 percent, which has been suggested from a bank in Korea. Tax rate has a discrete distribution with 25 percent and 30 percent. Indonesia's corporate tax rate has remained at 25 percent since 2010; it had been 30 percent before 2010 [63].

Table 26: Value Drivers Using a Probability Distribution for a Monte Carlo Simulation

Value drivers	Unit	Expected value	Distribution	Range (min/max)
Toll fee	USD/ MMBTU	1.0	Uniform	0.8 1.0 1.2
Initial gas demand (Power Plant & Industrial)	MMSCFD	29.10	Uniform	23.28 29.10 34.92
Growth rate of gas demand	%	5.1	Triangular	2.5 5.1 7.7
CAPEX	USD	93,560,000	Triangular	78,848,000 112,272,000
OPEX	USD/ MMBTU	0.20	Triangular	0.15 0.20 0.40
Cost of debt	%	2.58	Triangular	2.58 6.00
Tax rate	%	25	Discrete	25 (80%) 30 (20%)

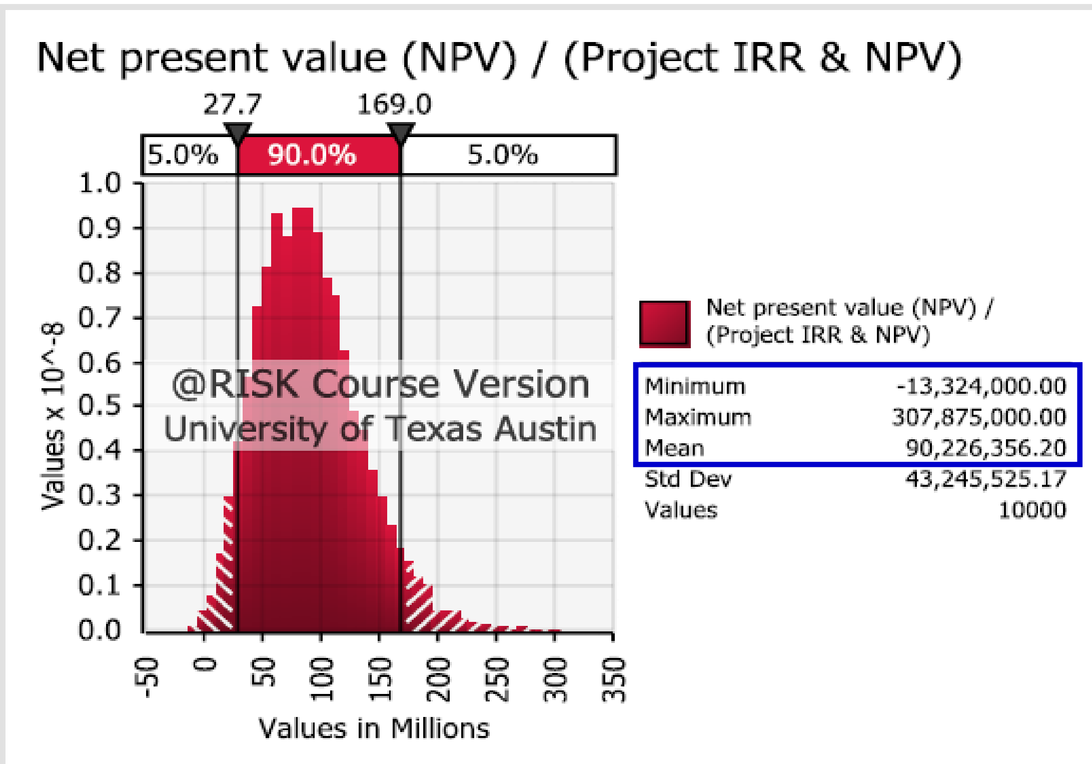
(Source: developed by Kim, D.H.)

Monte Carlo simulations by using @Risk software have been solved for 10,000 iterations, based on defined value drivers and constructed cash flow. Output variables include project NPV, project IRR, equity NPV, and equity IRR. This thesis discusses below only the result of project NPV and project IRR in which KOGAS might interest.

Fig. 9 shows the result of Monte Carlo simulation of the project IRR. The mean value of project NPV is approximately 90 million USD and standard deviation is about 43 million dollars. The maximum value is 307 million USD while the minimum value is about -13 million USD. The probability that the project NPV has a negative value only accounts for 0.3 percent of the simulated distribution (Fig. 10). It means that there is a

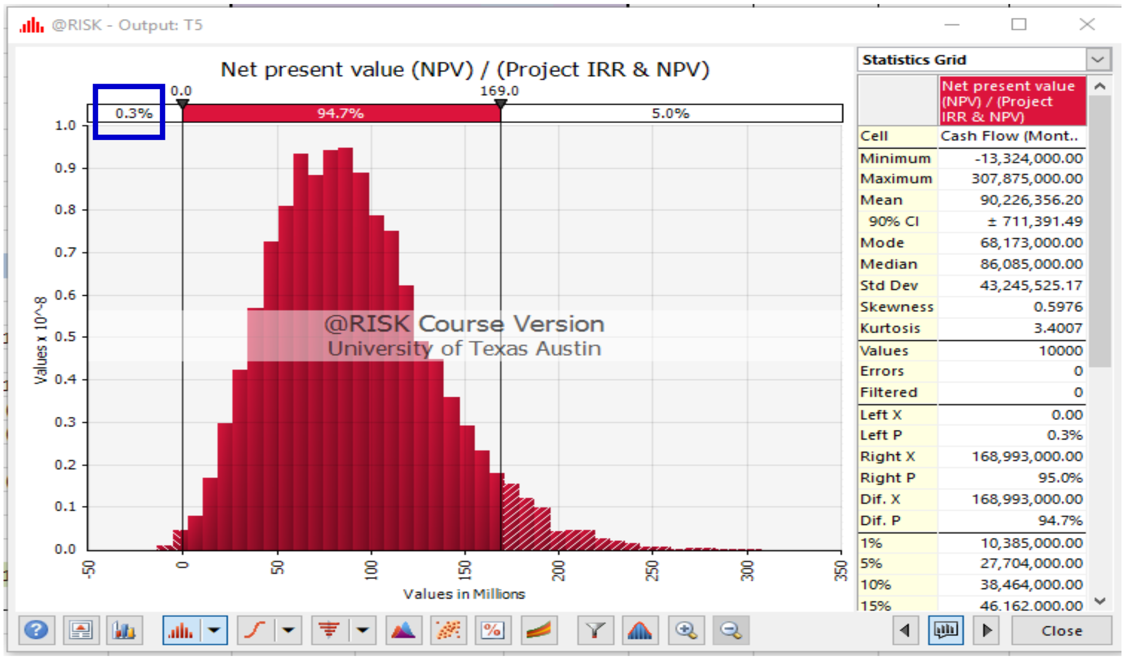
99.7 percent chance that the investment would generate cash flows making a positive NPV. Based on the result of project NPV by Monte Carlo simulation, the South Sumatra Natural Gas Pipeline Project might be good option for KOGAS. Therefore, KOGAS might advance to a feasibility study or FEED.

Figure 9: Simulation Output for the Mean Value of Project NPV



(Source: developed by Kim, D.H.)

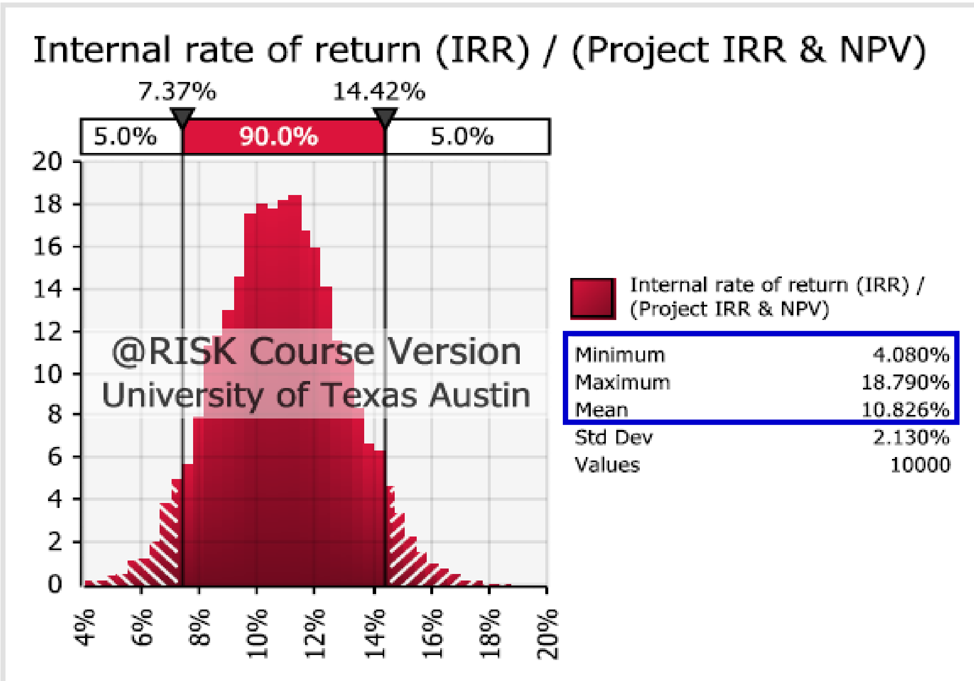
Figure 10: Simulation Output for the Probability of Project NPV



(Source: developed by Kim, D.H.)

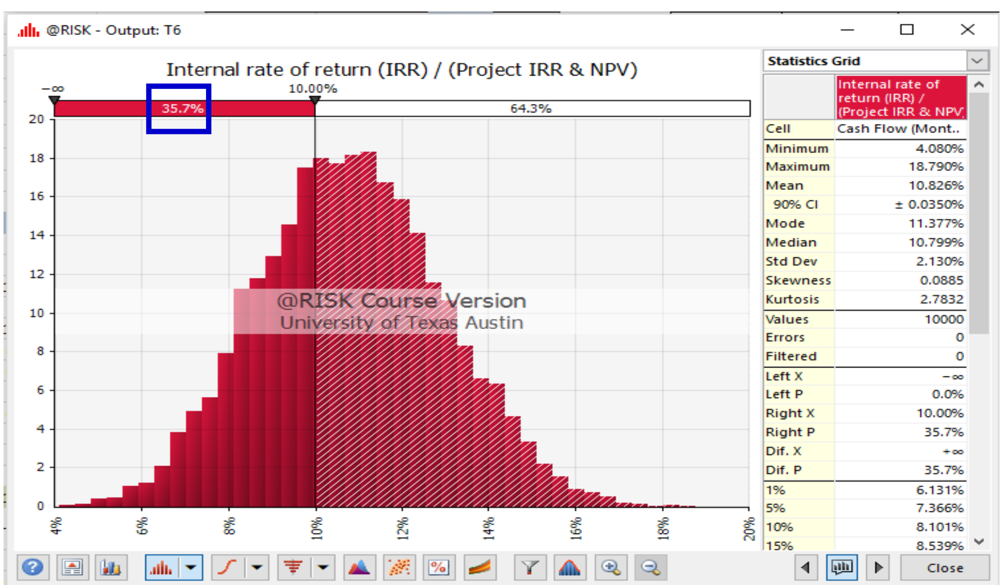
Even if project NPV yields a positive NPV, KOGAS' regulation requires a higher project IRR than 10 percent. Fig. 11 shows the simulation result of the project IRR. The mean value of project IRR accounts for 10.8 percent, and the standard deviation is 2.1 percent. It can be interpreted that a mean of the project IRR falls between 7.37 percent and 14.42 percent with a 90 percent confidence. However, as shown in Fig. 12, there is a 35.7 percent chance that the project IRR will be less than 10 percent, which is a lower limit of return that KOGAS can accept for an investment. It demonstrates that the South Sumatra Natural Gas Pipeline Project might have some risks in spite of 99.7 percent possibility of positive NPV. If KOGAS decides to further advance, KOGAS might need an additional study about which value drivers could affect the project. A more detailed sensitivity analysis could develop useful information.

Figure 11: Simulation Output for the Mean Value of Project IRR



(Source: developed by Kim, D.H.)

Figure 12: Simulation Output for the Probability of Project IRR



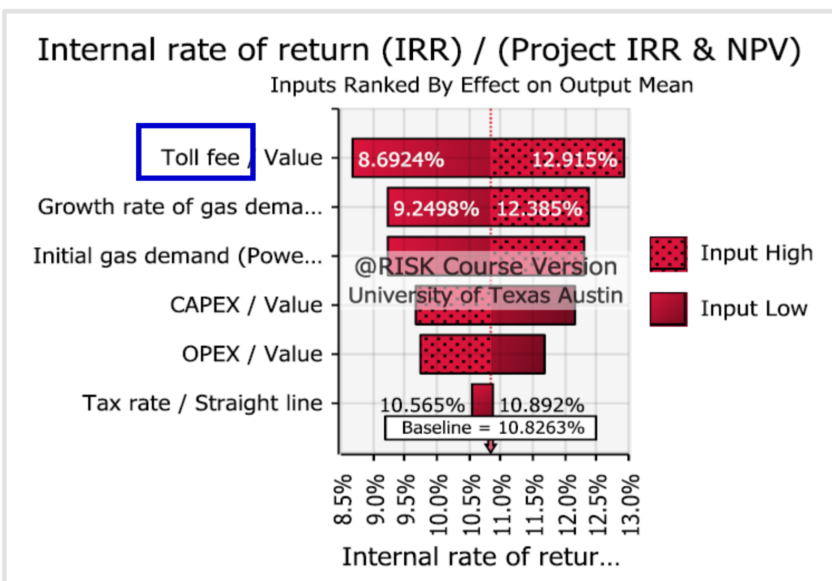
(Source: developed by Kim, D.H.)

5.6 Sensitivity Analysis

Sensitivity analysis provides a systematic way to analyze how changes in an investment's value driver can affect the project IRR or project NPV. This thesis performs a sensitivity analysis by using @Risk software. The results can be illustrated as a tornado diagram with a result of output variables.

Figure 13 illustrates the result of the sensitivity analysis with regard to the project IRR. The cost of debt is removed from seven value drivers because the cost of debt has nothing to do with project IRR. Figure 13 indicates that toll fee has the greatest impact on project IRR as indicated at the top of the diagram. Each of the other factors has a successively smaller effect on the project IRR down the figure, creating a funnel-shaped diagram. By a variation of toll fee, the project IRR ranges from 8.7 percent to 12.9 percent. In the same way, the variation of the growth rate of gas demands makes the project IRR range from 9.2 percent to 12.4 percent.

Figure 13: Result of the Sensitivity Analysis of the Project IRR



(Source: developed by Kim, D.H.)

Figure 13 illustrates that value drivers involving revenues, which includes toll fee, growth rate, and initial gas demand, have a larger impact on project IRR than expense's side such as CAPEX, OPEX, and tax rate. It means that KOGAS may have to better understand initial gas demand and a growth rate. The result also could motivate KOGAS and PDPDE to obtain a higher toll fee from the negotiation with BPH MIGAS under the existing regulations.

From Chapter 4 and Chapter 5, this thesis identified the supply risk from insufficient gas reserves and sensitive value drivers to affect an economic viability of the project. To minimize these risks and maintain an economic viability of the South Sumatra Natural Gas Pipeline Project, KOGAS ought to manage identified risks through risk management as discussed in Chapter 6.

Chapter 6: Risk Management

This chapter discusses risk management to identify significant risks and establish mitigation strategies of the South Sumatra Natural Gas Pipeline Project. Among Asian privatized infrastructure projects, only approximately 30 percent of projects have resulted in satisfactory outcomes [64]. It means the importance of a risk management which could play an important role to minimize risks and maintain a required project IRR of KOGAS.

6.1 Risk in Infrastructure Projects

To meet growing public service demands, some governments might solicit private investments for public infrastructure through privatization or joint public/private investments (JPPI). JPPI can help a developing country expand infrastructure by diversifying sources for capital investment [65]. A typical approach would be of a government to grant the private sector the right to finance, design, and construct a specific infrastructure and operate it for a concession period [66]. Private participation in infrastructure projects can transfer project risks, financial risks, or administrative burden form the public to the private sector [66]. One key element is for the private sector to identify the risks associated with projects and to formulate appropriate risks management strategies to deal with them [66].

6.1.1 Risk Management

Risk management is the process of identifying and assessing different risks, planning risk mitigation, implementing a risk mitigation plan, and controlling risks [67].

The objective of project risk management is to decrease the probabilities and impacts of events adverse to project purposes [67].

The first step of risk management is risk identification or determining the source of risks that may affect a project, through methods such as benchmarking, brainstorming, Delphi techniques, interviews, historical data from similar projects, questionnaires, risk breakdown structure, or workshops [67]. Among those tools, data and knowledge from prior similar projects might be useful in identifying risks relative to infrastructure projects. For example, the section below discusses risks of the South Sumatra Natural Gas Pipeline Project as a build-own-operate (BOO) project, one of various public-private partnership (PPP) models.

6.1.2 Public-Private Partnership

A public-private partnership (PPP) is an agreement between a host government and a private entity. The private sector supplies infrastructure assets and services traditionally provided by a government [68]. If the private partner pays for the infrastructure constructions, the PPP approach can relieve a government of budgetary pressure for infrastructure construction. There are different forms of PPP, according to the extent of private involvement in public projects [68]. The South Sumatra Natural Gas Pipeline Project might be classified as a case of build-own-operate.

Under Indonesia's Government Regulation No.36/2004, downstream businesses that operate through an Indonesian incorporated entity must acquire a business license issued by the MEMR (Ministry of Energy and Mineral Resource) with advice from BPH MIGAS [9]. KOGAS-PDPDE must also obtain Special Rights from MEMR in order to transmit gas via pipeline within the stipulated transmission and distribution routes [12].

In the BOO model, the government grants the right to design, build, finance, operate, and maintain a project to a private entity in a manner similar to a build-operate-transfer (BOT) model [69]. BOO or BOT project can be a complex and risky undertaking due to many uncertainties: delays in completion, cost overruns, technical and financial failure, expropriation, poor management, and legislative or regulatory changes [66]. Risks vary according to the country and project. PPP project risks can be divided into two categories: general risks and project risks [70], as discussed below.

6.1.3 General Risks in Infrastructure Projects

General risks reflect macro-environmental factors of the host country, such as the political environment, economic conditions, the legal system, taxation, or fluctuations in the currency exchange rate [66]. These can be subdivided into political risks, financial risks, and legal risks.

Political risks involve issues or concerns associated with the local, regional, national political situation, and the regulatory situation of the host country [71]. Not only do governments play an important role in infrastructure project, but they also represent a constant risk source by interfering with projects. Among the political risks, sovereign risks include an expropriation of assets by the government, restriction of operating freedom, financial penalties, and constraints of repatriation. Instability risks are associated with a cancellation or revision of contracts and damage to property from terrorism or riot [66]. The public can be a political risk if a project owner is a foreign entity or if the project is located in an urban setting with no perceived value-added benefit [68]. To hire local contractors might be a possible solution to mitigate risks from the public due to their direct participation in the project.

Financial risks are associated with the host country's economic environment, which includes currency devaluation, foreign exchange fluctuations, fluctuations in interest rate, and inflation [66]. The fluctuations of interest rate occur due to the investment through long-term loans, which might affect the cost of debt and projected revenue. Foreign exchange rate changes can affect revenue. Because net revenue of the project is often denominated in a foreign currency, a project company is exposed to exchange rate risk, as the foreign currency may depreciate against the domestic currency of the project company [68].

Legal risks result from changes in laws or regulations and legal systems which may adversely affect a project [66]. Some changes in tax rate, local content rate, corporate and environmental regulations, the terms of a project, and rejection of permit extension might disrupt a project's cash flow.

6.1.4 Project Risks in Infrastructure Projects

Project risks directly relate to project phases: development, construction, and operation.

In the development phase, all pipeline projects begin with an idea or a concept that might fill a specific need, within a specific time, and at a specific location [71]. Primary participants would discuss their roles and expectations. They may specify a project concept through feasibility to financing. For some infrastructure projects, participants are responsible for the arrangement of project finance. In developing countries, some projects may be financed by a government borrowing from the international banking market, development-finance institutions such as the World Bank, or through export credits [72]. Introduction of private finance through public-private partnerships can transfer a share of the financing burden to the private sector. A delay or failure of a financial closing can affect the development phase. Development-phase risks include defects in the request for proposal, planning and approval delays, errors in economic and technological assessment, or rejection of the proposal by the granting authority [66].

Construction-phase risks reflect whether a project can be completed on time, on budget, and to the required specification [72]. Some construction-phase risks include site acquisition and access, site condition, permits, risks relating to the construction contractor, cost overruns, delay in project completion, third-party risks, inadequate performance on project completion [72]. Among these construction phase risks, cost overruns and delay in project completion may be most important factors. Cost overruns can affect the profitability of the project by increasing construction and financing costs [66]. It is difficult to foresee the overall cost due to inherent construction uncertainty. In spite of a feasibility study or front end engineering design (FEED) in a development phase, the project cannot eliminate cost-overrun risk. In some projects, the application of advanced technology can complicate the construction phase. For example, unexpected underground conditions can be a source of risks. Right of way (ROW) issues also cause both cost overruns and delay as pipelines pass through local population centers. ROW acquisition is both an economic issue and a socially sensitive issue involving matters of public need and property owner rights [73]. Completion delays may have several consequences [72]: financing costs will be higher because the construction debt is outstanding for a longer period; revenues from operating the project will be deferred; and penalties may be imposed by the off-takers or suppliers.

Operation-phase risks mainly relate to insufficient revenue and an increased cost of operation and maintenance (O&M) [66]. Insufficient revenue is associated with an off-take risk, which involves any reduction in or failure of the use of the services provided by the facility [74]. The main cause of the off-take risk might be a reduced demand for the off-take, inability of the off-taker to pay for the off-take, technical or practical difficulties with delivering the off-take, and public reaction which result in a boycott against the off-take [74]. Insufficient revenue also relates to the level of penalty or abatement for under performance or the index linked payment period [70]. The project must meet given performance levels to earn revenues to pay operating costs, repay debt, and achieve the levers of profit. Efficiency reductions during operating phase, caused by equipment malfunction or damage to facilities, can increase O&M cost and disrupt a project's revenue streams.

6.2 Risk Management of the South Sumatra Natural Gas Pipeline Project

The South Sumatra Natural Gas Pipeline Project, categorized as a BOO, may face many of the risks discussed above. Because KOGAS has not completed a feasibility study or FEED yet, it will incur costs further studies. Development phase risks could affect KOGAS' capacity to execute the project, which should be thoroughly reviewed prior to an investment through the feasibility study, commercial and technical evaluations, and legal reviews. Sub-sections below identify general and project risks and also suggest mitigation strategies.

6.2.1 General Risks and Mitigation Strategies

Indonesia has climbed in the World Bank's Doing Business ranking from 114th in 2014 to 72nd in 2017 under the leadership of Indonesian President Joko Widodo [75].

This positive development is related to the Indonesian government's effort to implement reforms to improve its business and investment climate [75]. The Indonesian government continues to announce policy reforms intended to reduce red-tape, strengthen the country's investment climate, and enable economic growth. President Widodo has undertaken several important efforts such as moving many government services online. Investors have welcomed policy reforms, which include opening sectors for investors and reducing high logistics costs [37].

AMBest reports that Indonesia has political risks due to the president's preference for domestic firms and resource nationalization [76]. Indonesian contract enforcement can be inefficient. Corruption in the legal system is reported to be relatively widespread [76]. The Corruption Perception Index ranks Indonesia 96 out of 180 countries in 2017 [77]. KOGAS or other participants may consider using the UN Global Compact Management Model in fighting corruption and implementing the 10th Principle (see Fig. 14). Business should work against corruption in all its forms, including extortion and bribery [78]. The UN recommends companies follow six steps: committing, assessing, defining, implementing, measuring, and communicating a corporate sustainability strategy based on the global compact against corruption [78]. However, it is not easy for companies such as KOGAS and PDPDE to break customs. KOGAS has a challenge to obtain a host government's guarantee of transparency in legal procedures as well as purchase appropriate insurance as preventative measures against political risks.

Figure 14: UN Global Compact Management Model

(Source: Figure in page 9 from [78])

AMBest reports that Indonesia has moderate levels of economic and financial system risk [76]. The Indonesia's economy has grown steadily and robustly over the past few years; for example, it expanded 5.1 percent in 2017. Inflation in Indonesia, which has been relatively stable in recent years, is projected to return to 3.5 percent in 2018 [76]. Moody's upgraded Indonesia's credit rating to BAA2 with stable outlook on April 2018 [79]. Standard & Poor's and Fitch ratings in 2017 stand at BBB- and BBB with stable outlook, respectively [80]. These grades correspond to a "low" investment grade rating. It may be "satisfactory", but an investor ought to monitor its risks [81]. In order to protect their investments, most investors restrict their investments to the minimum rated investment grade, which corresponds to BBB (Standard & Poor's) and BAA2 (Moody's) [81]. Credit ratings affect the cost of borrowing, meaning that the higher credit ratings, the lower interest rates, which will bring a positive effect on the cash flow.

Fluctuation in foreign exchange rates remains a key financial risk. If KOGAS cannot make a profit in U.S dollars, the company may hedge foreign exchange risks. Indonesia's central bank recently urged businesses to hedge their foreign exchange needs beyond minimum requirements, as policymakers seek to mitigate risks of further capital outflows following the rupiah's slump [82].

One way to mitigate risks is to use Indonesia's infrastructure guarantee program, as launched in 2006 as Ministry of Finance Regulation No. 38/PMK/2006 [83]. This regulation prescribes procedures for submitting proposals to seek government guarantees against political, project performance, and demand risks. Political risks include expropriation, change in legislation, and inconvertibility/transferability of foreign exchange. Project performance risks encompass land acquisition risk, tariff risk, and changes in output specification. Demand risks are to protect the project sponsor from up and downside demand [83]. Although this program has been applied only to BOT projects, KOGAS might attempt to adopt it for the South Sumatra Natural Gas Pipeline Project by negotiating with the Indonesian government.

6.2.2 Project Risks and Mitigation Strategies

The South Sumatra Natural Gas Pipeline Project may include several project risks according to its project phases; development, construction, and operation.

In the development phase, the most significant risks are the revision of the master plan, the actual volume of gas reserves, and uncertain gas demands (see Table 27). The current master plan for the development of TAA SEZ considers a coal-fired power plant. If BPH MIGAS does not change its master plan (from a coal-fired power plant to a natural gas-fired power plant), KOGAS could have to delay or cancel its participation in the project. Insufficient supply of gas and decreasing long-term gas reserves could create gas shortage for off-takers and subsequently interrupt project cash flow, as mentioned in Chapter 4.2.3. The anticipated available gas volume for the South Sumatra Natural Gas Pipeline Project might be only 1,396 billion cubic feet (BCF) at a maximum rate. This reserve is not sufficient for potential gas demands for power generation and industrials in Scenario 2 or Scenario 3. If KOGAS cannot secure guaranteed gas reserves for a thirty-year supply from other gas fields, it could delay or cancel the project. Uncertain gas demand could be a key risk for the project. The stagnant growth in the TAA SEZ and growth rate of gas demands could affect project sustainability. Securing a long-term gas transportation agreement (GTA), including the provision of take-or-pay (TOP) with gas trading companies, might mitigate the risk related to uncertain gas demand. TOP provision requires purchasers to pay for a pre-specified minimum quantity of natural gas whether or not they take the gas, and producers require delivering this quantity of gas [84]. As GTAs might discourage off-takers to switch to alternative fuels, KOGAS might assure the stable cash flow during contracted period. Any delay or difficulty in project finance could delay project initiation. KOGAS has planned to use project finance to minimize the equity under an investment regulation of the Korean government and for the risk mitigation. However, the process of project finance is not simple due to the due diligence and the lender's requirements. Therefore, the support of the State of South Sumatra and active collaboration of KOGAS and PDPDE might be helpful for the efficient and fast due diligence by mitigating remained risks. Table 27 lists some of the key risks and risk mitigation strategies.

Table 27: Project Risks and Mitigation Strategies in Development Phase

Identified risks	Mitigation strategies
Revision of the master plan from coal-fired power plant to gas-fired power plant	Persuade the government to change their plan, or delay/cancel the project
Insufficient gas reserve	Conduct a supply study to accurately figure out the amount of available gas for the project
	If the gas reserve is not enough to secure an appropriate NPV/IRR, delay/cancel the project
Uncertain gas demand	Examine demand projections and information on the willingness of trading companies to pay tariff
	Secure long-term gas transportation agreement (GTA) including the provision of take-or-pay (TOP) before an investment to discourage them to switch to alternative fuels
	If the gas demand is not enough to secure an appropriate NPV/IRR, delay/cancel the project
Delays in necessary approvals (license and permits for the transportation business)	Obtain consistency in the policy through all levels of government agencies
	Assistance of the South Sumatra government and local company (PDPDE)
Errors in feasibility studies	Employ independent consultants for careful feasibility studies
Difficulty in project finance	Support of the State of South Sumatra
	Support of KOGAS-PDPDE for smooth due-diligence
Partners	Verify the participants' financial conditions

(Source: developed by Kim, D.H.)

In the construction phase, the identified risks are cost overruns, completion delays, the issue of right of way (ROW), and technical issues to connect KOGAS-PDPDE pipelines with existing PUSRI pipelines (see Table 28). An estimated cost prior to FEED includes high risks related to cost overruns. To mitigate KOGAS risks, lump-sum construction contracts might be one way to transfer the risk to contractors. Under the lump-sum method, a pre-agreed sum, regardless of actual cost incurred, is paid by the employer. Works actually done are not measured but paid against the payment schedule [85]. Through the lump-sum contracts, KOGAS might transfer the financial risk to contractors. KOGAS still has a challenge to assure contractor quality, so as to maximize the profit within fixed cost. In this case, binding contractors to project equity sharing might be a mitigation strategy to avoid cost overruns and poor quality. By participating in equity sharing, the contractor will be concerned with the return on equity during operation period. Completion delay might result in higher financing cost, deferred revenue, and penalties by gas suppliers or off-takers, as discussed above. KOGAS can diminish the risk related to the delay in completion through a contractor performance bond. A performance bond can secure the risk that the contractor may breach its duty to complete the works [85]. Acquiring ROW for gas pipeline projects can be costly and time consuming. Because delay in the ROW acquisition process can lead to major delays in construction, dealing with ROW in a timely manner would help begin project construction on an approved schedule [73]. The assistance of PDPDE or the State of South Sumatra might be helpful in resolving ROW issue with local populations. KOGAS may have to install gas pipeline under public land alongside existing traffic roads. KOGAS may also seek to transfer the responsibility of the ROW to EPC contractors. According to the open access policy under Law No.36/2004 of Indonesia, KOGAS-PDPDE pipeline might connect with the existing Grissik-Pusri pipeline. KOGAS-PDPDE needs to resolve technical issues related to the connection of pipelines and discuss about the appropriate schedule to connect pipelines to avoid any disruption to supply gas to the Pusri plant. Table 28 lists project risks and risk mitigation strategies for the construction phase.

Table 28: Project Risks and Mitigation Strategies in Construction Phase

Identified risks	Mitigation strategies
Cost overruns	Lump-sum construction contracts
	Bind contractors to participate in project equity sharing
	Obtain standby credit as contingency
	Secure an appropriate contingency in estimating CAPEX
Completion delays	Request performance bond
	Add specific provisions for early completion incentives and liquidated damages to contract
	Efficient construction management by KOGAS
Subsurface condition to install pipelines	Ensure the technical study to survey geotechnical condition and propose appropriate mitigation plans
Right-of-way	Risk transfer to a contractor
	Guarantee of assistance of the State of South Sumatra and PDPDE
	Make all administrative procedures transparent
Connection between KOGAS-PDPDE pipeline and PUSRI pipeline	Check the specification required to connect pipelines and negotiate a tapping schedule with the owner of Pusri pipeline

(Source: developed by Kim, D.H.)

In the operation phase, the risks such as insufficient gas supply, capacity of the flow rate, revenue, rejection of permit extension, and force majeure exist in the South Sumatra Natural Gas Pipeline Project (see Table 29). The most significant risk may be a revenue risk as discussed previously. KOGAS-PDPDE generates revenues through transportation activities by transmitting natural gas via their pipeline, so KOGAS-PDPDE ought to monitor the growth rate of TAA SEZ. They may also monitor an appropriateness of current tariffs and projections of off-takers' attitudes toward paying increased tariffs. Another risk is the extension of the transportation license and Special right, so that KOGAS-PDPDE can operate for thirty years. KOGAS may seek a guarantee of the State of South Sumatra or central government for the permit extension. To mitigate force majeure for the operation phase, KOGAS could obtain standby credit as a contingency and purchase proper insurance policies. Table 29 lists project risks and risk mitigation strategies for the operation phase.

Table 29: Project Risks and Mitigation Strategies in Operation Phase

Identified risks	**Mitigation strategies**
Capacity of the flow rate via KOGAS-PDPDE pipeline	Work closely to the owner of PUSRI pipeline to correspond to the variation of their gas flow and pressure
Revenue risk	Monitor prospects for the growth rate of gas demand, appropriateness of current tariffs, and projections of consumer attitudes toward paying increased tariffs
	Secure a long-term gas transportation agreement (GTA) including the provision of take-or-pay (TOP) with new off-takers to discourage them to switch to alternative fuels
Rejection of permit extension	Obtain the host government's guarantee of the permit extension, or prepare the alternative way to deal with KOGAS-PDPDE pipeline
	Proactively engage the government agencies
Force majeure	Obtain standby credit as contingency
	Purchase proper insurance

(Source: developed by Kim, D.H.)

Chapter 7: Conclusion

This thesis performed an economic analysis of the South Sumatra Natural Gas Pipeline Project to assess its economic viability based on its discounted future cash flow. For producing revenues, this study assessed the potential gas demand for electricity generation of 79.1 MMSCFD and industrial feedstock of 211.7 MMSCFD. The estimated maximum gas demand was adjusted by calculating the capacity of the flow rate to be 248.5 MMSCFD. This research also analyzed the availability of gas source from gas fields to ensure KOGAS-PDPDE's transmission, which demonstrated a substantial risk in sustainability of thirty-year operation depending on the growth rate. The result of supply analysis showed that KOGAS may need additional gas reserves to secure thirty-year supply contracts. To estimate project costs, this study analyzed historical pipeline projects in the U.S. and estimated unit project CAPEX (USD/inch-mile) including labor, materials, ROW, and miscellaneous costs. This study developed multipliers for each costs component from comparisons between the United States and Indonesia. Compared to a unit cost of 159 USD per inch-meter in the U.S., the unit cost for the South Sumatra Natural Gas Pipeline Project was estimated to be 63.22 USD per inch-meter.

From the discounted future cash flow, this thesis calculated NPV and IRR with regard to three scenarios, based on different growth rates. All scenarios have a positive NPV and a project IRR that exceeds 10 percent, which is a KOGAS' investment threshold. Two dimensional data analysis between WACC and the growth rate of gas demand showed that WACC ought to be less than 9 percent and the growth rate of gas demand is larger than 3 percent, with other factors held constant. This study performed a Monte Carlo simulation by using @Risk software to evaluate a probability for the project IRR to be less than the KOGAS' investment threshold. The simulation showed that there is a 35.7 percent probability that the project IRR will be less than 10 percents in Scenario 1. This probability would encourage KOGAS to perform a risk management to maintain an economic viability of the South Sumatra Natural Gas Pipeline Project. Sensitivity analysis identified substantial risk factors, such as toll fee, growth rate, and initial gas demand.

In addition, this paper analyzed primary risks and mitigation strategies to successfully implement the South Sumatra Gas Pipeline Project in Indonesia. Both general risks and project risks were analyzed. The general risks discussed include political risks, financial risks, and legal risks. The project risks were analyzed according to project phase such as development phase, construction phase, and operation phase. Natural catastrophes, such as earthquakes or tsunamis, or human-made catastrophes, including terrorism or gas piping damage, are beyond the scope of this thesis, although KOGAS might wish to evaluate their challenge.

Based on the economic analysis in this research, this project could be a viable project for KOGAS. However, this result of economic analysis and identified risks ought to be thoroughly reviewed through a feasibility study, commercial and technical review, and legal reviews prior to an investment. In addition, collaborative working relationships between KOGAS, Indonesian government, and numerous contractors might play an important role to achieve the economic viability of the South Sumatra Gas Pipeline Project. The effective management of the South Sumatra Natural Gas Pipeline Project should strengthen KOGAS' capability for overseas business and also enhance Indonesia's economic development.

Bibliography

[1] British Petroleum, 2017, Energy Outlook 2017, https://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2017/bp-energy-outlook-2017.pdf (examined 30 Jul. 2018).

[2] EIA, 2017, International Energy Outlook 2017, https://www.eia.gov/outlooks/ieo/pdf/0484(2017).pdf (examined 28 Jul. 2018).

[3] EIA, 2018, Country Analysis Brief: South Korea, https://www.eia.gov/beta/international/analysis_includes/countries_long/Korea_South/south_korea.pdf (examined 21 Sep. 2018).

[4] Puwanto, W.W., Muharam, Y., Pratama, Y.W., Hartono, D., Soedirman, H., and Anindhito, R., 2016, Status and Outlook of Natural Gas Industry Development in Indonesia, *Journal of Natural Gas Science and Engineering*, v. 29, p. 55-65.

[5] Wood Mackenzie, 2018, Global Gas Markets Long-term Outlook, https://my.woodmac.com/reports/gas-markets-global-gas-markets-long-term-outlook-asia-gas-and-lng-h1-2018-56489969?contentId=56489969#56489990 (examined 5 Sep. 2018).

[6] EIA, 2015, Indonesia Country Analysis Brief, https://www.eia.gov/beta/international/analysis_includes/.../Indonesia/indonesia.pdf (examined 25 Jul. 2018).

[7] KOGAS, and PDPDE, 2016, Memorandum of Understanding-Infrastructure Projects in South Sumatra, Indonesia.

[8] Hasan, M.H, Mahlia, T.M.I., and Nur, H., 2012, A review on energy scenario and sustainable energy in Indonesia, *Journal of Renewable and Sustainable Energy Reviews*, v. 16, p. 2316-2328.

[9] PWC, 2018, Oil and gas in Indonesia – Investment and Taxation Guide, https://www.pwc.com/id/en/energy-utilities-mining/assets/oil-and-gas/oil-and-gas-guide-2018.pdf (examined 5 Sep. 2018).

[10] IEA, 2014, Energy Supply Security of Indonesia 2014, https://www.iea.org/publications/freepublications/publication/ESS_Indonesia_2014.pdf (examined 19 Sep. 2018).

[11] ICLG, 2018, Oil & Gas Regulation 2018. International Comperative Legal Guides, https://iclg.com/practice-areas/oil-and-gas-laws-and-regulations/Indonesia (examined 20 Sep. 2018).

[12] GBG Indonesia, 2017, Oil and Gas Transportation and Infrastructure in Indonesia, Global Business Guide Indonesia, http://www.gbgindonesia.com/en/main/legal_updates/oil_and_gas_transportation_and_infrastructure_in_indonesia.php (examined 10 Sep. 2018).

[13] BPH MIGAS, 2014, Open Access Policy by BPH MIGAS, http://indonesiangassociety.com/wp-content/uploads/2016/06/Keynote-2-Andy-N.-Sommeng.pdf (examined 21 Sep. 2018).

[14] Republic of Indonesia National Council for Special Economic Zone, 2018, Tanjung Api-Api, http://kek.go.id/kawasan/Tanjung-Api-Api (examined 25 Jul. 2018).

[15] ASEAN briefing, 2018, Indonesia's Growing Special Economic Zones-Opportunities and Challenges, https://www.aseanbriefing.com/news/2018/08/24/indonesias-growing-special-economic-zones-opportunities-and-challenges.html (examined 11 Nov. 2018).

[16] BKPM, 2017, Opportunities for Foreign Direct Investment in Indonesia, http://www.boi.go.th/upload/BKPM_Updated_84830.pdf (examined 20 Sep. 2018).

[17] Nusantara Maritime News, 2016, Tanjung Api-Api to be Energy Industrial Area, https://maritimenews.id/03/jxjkljLLx/ (examined 5 Sep. 2018).

[18] KOGAS, and PDPDE, 2016, Minute of Meeting.

[19] Shell, 2017, Shell LNG Outlook 2017, http://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-lng/lng-outlook/_jcr_content/par/textimage_1374226056.stream/1488553856456/88c077c844a609e05eae56198aa1f92d35b6a33cc624cf8e4650a0a6b93c9dfb/shell lng-outlook-2017-overview.pdf (examined 28 Oct. 2017).

[20] EIA, 2017, International Energy Outlook 2017, https://www.eia.gov/outlooks/ieo/pdf/0484(2017).pdf (examined 28 Jul. 2018).

[21] Pertamina Gas, 2017, Petagas to Team up with Rekind for the Construction of Grissik-Pusri Gas Pipeline, http://www.pertagas.pertamina.com/pertagas-to-team-up-with-rekind-for-the-construction-of-grissik-pusri-gas-pipeline (examined 5 Sep. 2018).

[22] Hogan Lovells, 2013, Doing Business in Indonesia, http://www.hoganlovells.com/files/upload/doing%20business%20in%20indonesia_reduced.pdf (examined 11 Sep. 2018).

[23] KOGAS, 2018, KOGAS Brochure 2018.

[24] State of South Sumatra, 2012, Master Plan of Tanjung Api-Api Special Economic Zone (SEZ).

[25] EIA, 2017, Power Plant Operations Report, https://www.eia.gov/todayinenergy/detail.php?id=32572 (examined 3 Oct. 2018).

[26] Wood Mackenzie, 2018, Corridor-Asset Report, https://www.woodmac.com/reports/upstream-oil-and-gas-corridor-556541 (examined 28 Oct. 2018).

[27] EIA, 2014, Electric Power Monthly, https://www.eia.gov/todayinenergy/detail.php?id=14611 (examined 3 Oct. 2018).

[28] Differ, 2012, The Indonesian Electricity System-a Brief Overview, http://www.differgroup.com/Portals/53/images/Indonesia_overall_FINAL.pdf (examined 3 Oct. 2018).

[29] State of South Sumatra, 2013, Site Plan of Tanjung Api-Api Special Economic Zone (SEZ).

[30] Parikh, J., Biswas, D., Singh, C., and Singh, V., 2009, Natural Gas Requirement by Fertilizer Sector in India, *Energy*, v. 34, p. 954-961.

[31] IETD, 2018, Industrial Efficiency Technology Database, http://ietd.iipnetwork.org/content/use-alternative-fuels (examined 9 Oct. 2018).

[32] Worrell, E., Price, L., Neelis, M., Galitsky, C., and Nan, Z., 2008, World Best Practice Energy Intensity Values for Selected Industrial Sectors, https://eaei.lbl.gov/sites/default/files/industrial_best_practice_en.pdf (examined 9 Oct. 2018).

[33] Francis, D.W., Towers, M.T., and Browne, T.C., 2002, Energy cost reduction in the pulp and paper industry, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/oee/pdf/publications/infosource/pub/cipec/pulp-paper-industry/pdf/pulp-paper-industry.pdf (examined 7 Oct. 2018).

[34] Wilfred, O.C., and Bourdelon, M.U., 2017, Comparative Analysis of Multiphase Pressure Drop equations, *International Journal of Engineering and Modern Technology*, Vol 3(4), p. 1-17.

[35] McAllister, E.W., 2009, Pipeline Rules of Thumb Handbook: A Manual of Quick, Accurate Solutions to Everyday Pipeline Engineering Problems, Elsvier Inc., p. 368.

[36] National Energy Council, 2017, Technology Data for the Indonesian Power Sector, http://www.ea-nergianalyse.dk/reports/1724_technology_data_indonesian_power_sector_dec2017.pdf (examined 7 Oct. 2018).

[37] World Bank, 2018, Indonesia's Overview, https://www.worldbank.org/en/country/indonesia/overview (examined 30 Oct. 2018).

[38] Kallanish Energy, 2018, ConocoPhillips Mulls Extension to Indonesia's Corridor Pact, http://www.kallanishenergy.com/2018/09/04/conocophillips-mulls-extension-to-indonesias-corridor-pact/ (examined 15 Oct. 2018).
[39] Wood Mackenzie, 2017, Jambi Merang-Asset Report, https://www.woodmac.com/reports/upstream-oil-and-gas-jambi-merang-556576 (examined 28 Oct. 2017).
[40] MEMR, Ministry of Energy and Mineral Resources, 2016, Provision of Raw Materials for Construction of Gas-based Industries, http://rocana.kemenperin.go.id/phocadownload/Raker_2016/11.%20bahan%20dj migas%20-%20rapat%20kerja%20kementerian%20perindustrian%202016.pdf (examined 19 Oct. 2018).
[41] KPMG, 2018, Equity Market Risk Premium – Research summary, https://assets.kpmg/content/dam/kpmg/nl/pdf/2018/advisory/equity-market-risk-premium-july-2018.pdf (examined 14 Jan. 2019).
[42] Deloitte, 2018, International Tax – Indonesia Highlights 2018, https://www2.deloitte.com/content/dam/Deloitte/global/Documents/Tax/dttl-tax-indonesiahighlights-2018.pdf (examined 14 Jan. 2019).
[43] U.S. Department of the Treasury, 2019, Daily Treasury Yield Curve Rates, https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/textview.aspx?data=yield (examined 14 Jan. 2019).
[44] Titman, S., and Martin, J.D., 2015, *Valuation: The Art and Science of Corporate Investment Decisions*, Pearson.
[45] NYU Stern, 2019, Country Risk Premium, http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html (examined 14 Jan. 2019).
[46] KOGAS, 2018, Balance Sheet http://www.alio.go.kr/popReportTerm.do?apbaId=C0147&reportFormRootNo=3 120 (examined 16 Jan. 2019).

[47] KOGAS, 2018, Income Statement
http://www.alio.go.kr/popReportTerm.do?apbaId=C0147&reportFormRootNo=3130 (examined 16 Jan. 2019).

[48] BPH MIGAS, 2013, Regulatory Agency of Oil and Gas Downstream Number 8 Year 2013 about Determination of Transport Rates through Gas Pipes Head of the Governing Downstream of Oil and Gas.

[49] Schoots, K., Rivera-Tinoco, R., Verbong, G., an Zwaan, B., 2011, Historical Variation in the Capital Costs of Natural Gas, Carbon Dioxide and Hydrogen Pipelines and Implications for Future Infrastructure, *International Journal of Greenhouse Gas Control*, 5(6): 1614-1623.

[50] INGAA, the Interstate Natural Gas Association of America, 2009, Natural Gas Pipeline and Storage Infrastructure Projections through 2030, https://www.ingaa.org/file.aspx?id=10509 (examined 21 Jan. 2019).

[51] INGAA, Interstate Natural Gas Association of America, 2014, North America Midstream Infrastructure through 2035: Capitalizing on our Energy Abundance, https://www.ingaa.org/File.aspx?id=21527&v=6be6e34a (examined 21 Jan. 2019).

[52] Oil & Gas Journal, 2016, Natural Gas Pipeline Profits, Construction Both Up, https://www.ogj.com/articles/print/volume-114/issue-9/special-report-pipeline-economics/natural-gas-pipeline-profits-construction-both-up.html (examined 21 Jan. 2019).

[53] Rui, Z., Metz, P.A., Reynolds, D.B., Chen, G., and Zhou, X., 2011, Historical Pipeline Construction Cost Analysis, *International Journal of Oil Gas and Coal Technology*, 4(3): 244-263.

[54] Average Salary Survey, Construction & Labor workers (Indonesia), https://www.averagesalarysurvey.com/construction-labor-workers/indonesia (examined 23Jan. 2019).

[55] U.S.DOC, the United States Department of Commerce, 2018, Steel Imports Report: United States, https://www.trade.gov/steel/countries/pdfs/2017/annual/imports-us.pdf (examined 23Jan. 2019).

[56] World Steel Association, 2018, World Crude Steel Output Increase by 5.3% in 2017, https://www.worldsteel.org/internet-2017/media-centre/press-releases/2018/World-crude-steel-output-increases-by-5.3--in-2017.html (examined 23Jan. 2019).

[57] U.S.DOC, the United States Department of Commerce, 2018, Steel Imports Report: Indonesia, https://www.trade.gov/steel/countries/pdfs/imports-indonesia.pdf (examined 23Jan. 2019).

[58] SEAISI, South East Asia Iron and Steel Institute, 2017, Performance of the ASEAN Iron and Steel Industry in 2017 and Outlook, http://seaisi.org/file/Performance%20of%20the%20ASEAN%20Iron%20and%20Steel%20Industry%20in%202017%20and%20Outlook_2018.pdf (examined 23Jan. 2019).

[59] Steel Benchmarker, 2019, Steel Benchmarker Prices, http://steelbenchmarker.com/files/history.pdf (examined 23Jan. 2019).

[60] U.S.DOL, the United States Department of Labor, 2019, https://www.bls.gov/cpi/questions-and-answers.htm (examined 23Jan. 2019).

[61] NUMBEO, 2019, Cost of Living Index for Country 2019, https://www.numbeo.com/cost-of-living/rankings_by_country.jsp (examined 23Jan. 2019).

[62] WGC, World Gas Conference, 2003, The Challenges of Further Cost Reductions for New Supply Options (Pipeline, LNG, GTL), http://pages.hmc.edu/evans/PipelinesTokyo.pdf (examined 23Jan. 2019).

[63] Trading Economics, 2019, Indonesia Corporate Tax Rate, https://tradingeconomics.com/indonesia/corporate-tax-rate (examined 5 Jan. 2019).

[64] Kwak, Y.H., 2002, Analyzing Asian Infrastructure Development Privatization Market, *Journal of Construction Engineering and Management*, 128(2): 110-116.

[65] Boudet, H.S., Jayasundera, D.C., and Davis, J., 2011, Drivers of Conflict in Developing Country Infrastructure Projects: Experience from the Water and Pipeline Sectors, *Journal of Construction Engineering and Management*, 137(7): 498-511.

[66] Lee, N. and Schaufelberger, J.E., 2014, Risk Management Strategies for Privatized Infrastructure Projects: Study of the Build-Operate-Transfer Approach in East Asia and the Pacific, *Journal of Management in Engineering*, 30(3): 05014001.

[67] Rumane, A.R., 2016, *Handbook of Construction Management: Scope, Schedule, and Cost Control*. CRC Press.

[68] Rebeiz, K.S., 2012, Public-Private Partnership Risk Factors in Emerging Countries: BOOT Illustrative Case Study, *Journal of Management in Engineering*, 28(4): 421-428.

[69] Pratap, K. V., and Charkrabarti, R., 2017, *Public-Private Partnerships in Infrastructure: Managing the Challenges*. Springer.

[70] Ng, A., and Loosemore, M., 2007, Risk Allocation in the Private Provision of Public Infrastructure, *International Journal of Project Management*, 25(1): 66-76.

[71] Nielsen, K.R., 2006, Risk Management: Lessons from Six Continents, *Journal of Management in Engineering*, 22(2): 61-67.

[72] Yescomb, E.R., 2014, *Principles of Project Finance*. Elsevier.

[73] Aleithawe, I., 2017, Right-of-way Acuquisition Workflow Model to Reduce Acquisition Duration, *Journal of Legal Affairs and Dispute Resolution in Engineering and Constructon*, vol. 9(3): 05017001.

[74] Delmon, J., 2017, *Public-Private Partnership Projects in Infrastructure*. Cambridge University Press.

[75] Indonesia Investements, 2017, World Bank's Doing Business 2018: Indonesia Climbs in Ranking, https://www.indonesia-investments.com/business/business-columns/world-bank-s-doing-business-2018-indonesia-climbs-in-ranking/item8360? (examined 30 Oct. 2018).

[76] AMBest, 2018, Best's Country Risk Report: Indonesia, http://www3.ambest.com/ratings/cr/reports/indonesia.pdf (examined 31 Oct. 2018).

[77] Transparency International, 2017, https://www.transparency.org/news/feature/corruption_perceptions_index_2017 (examined 30 Oct. 2018).

[78] UN, United Nation, 2011, Business against Corruption: A Framework for Action, https://www.unglobalcompact.org/docs/news_events/8.1/bac_fin.pdf (examined 29 Oct. 2018).

[79] Moody's, 2018, Rating Symbols and Definitions, https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004 (examined 16 Jan. 2019).

[80] Trading Economics, 2018, Indonesia: Credit Rating, https://tradingeconomics.com/indonesia/rating (examined 30 Oct. 2018).

[81] AAII, American Association of Individual Investors, 2018, How Credit Ratings Affect Bond Valuations, https://www.aaii.com/journal/article/how-credit-ratings-affect-bond-valuations.touch (examined 30 Oct. 2018).

[82] Reuters, 2018, Indonesia Urges Firms to Bolster Hedging as Rupiah Risks Grow, https://www.reuters.com/article/indonesia-rupiah/update-3-indonesia-urges-firms-to-bolster-hedging-as-rupiah-risks-grow-idUSL3N1S215P (examined 25 Oct. 2018).

[83] Wibowo, A. and Kochendoerfer, B., 2011, Selecting BOT/PPP Infrastructure Projects for Government Guarantee Portfolio under Conditions of Budget and Risk in the Indonesian Context, *Journal of Construction Engineering and Management*, 137(7): 512-522.

[84] Crocker, K.J, and Masten, S.E., 1991, Prices and Process in Long Term Contracts, *Journal of Law and Economics*, vol. 34(1), p. 69-99.
[85] Klee, L., 2018, *International Construction Contract Law*. John Wiley & Sons Ltd.