ERIA Research Project Report 2020 No. 18

Feasible Solutions to Deliver LNG to Midsized and Large Islands in Indonesia

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ERIA Research Project Report FY2020 No. 18

Published in January 2021

Preface

Indonesia's electricity demand will increase significantly, by about 4.5 times, from 2017 to 2040 under the business-as-usual scenario, according to the East Asia Summit Energy Outlook 2017 edition of the Economic Research Institute for ASEAN and East Asia. This increase will be realised not only in the big cities, such as Jakarta and Surabaya, but also on Indonesia's small and midsized islands. As Indonesia is also rich in coal and natural gas, given the global challenges posed by climate change, natural gas will become an increasingly interesting source of power generation for Indonesia.

Eastern Indonesia is made up of two big islands: Sulawesi and West Papua (former Irian Jaya), and several groups of very diverse smaller islands, such as the Maluku and Nusa Tenggara islands. Around 41 million people inhabited these parts in 2017, accounting for around 16% of Indonesia's total population. Eastern Indonesia has three natural gas production sites: Bontang, Donggi Senoro, and Tangguh, and one planned production site – Masela LNG Block. The potential of shifting power generation sources from diesel to natural gas using small-scale liquefied natural gas (LNG) carrier vessels in this area is promising.

This report proposes a strategy for delivering small-scale LNG carrier vessels from LNG production sites to LNG power generation plants in Eastern Indonesia based on a personal computer-based dynamic simulation model. According to projected LNG demand at LNG power plants, forecast based on electricity demand at each demand site in Eastern Indonesia, the model seeks feasible solutions for delivering LNG from the origin to a destination using a computer simulation approach. The major outcomes of the dynamic simulation model are necessary number of LNG ships, maximum capacity of LNG receiving tanks, and their costs, consisting of capital and operating costs.

This study had to use tentative assumptions due to lack of data and information, but provided many meaningful results. I hope this study report will help Indonesia adopt appropriate policies to reallocate LNG production sites for export use and domestic use.

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President, Economic Research Institute for ASEAN and East Asia

Acknowledgements

This report was developed by a team from the Economic Research Institute for ASEAN and East Asia (ERIA) and a working group comprising Indonesian experts: Fathor Rahman (Masyarakat Ketenagakerjaan Indonesia/Indonesian Electricity Society); Tri Tjahjono (Civil Engineering Department, University of Indonesia); Hadi S. Ari (Port Operation Staff at the Directorate of Seaport Affairs, Ministry of Transport, Indonesia); and Yunika F. (Port Planning Subdivision Staff at the Directorate of Seaport Affairs, Ministry of Transport). I would like to thank the members of the working group for their excellent comments, suggestions, advice, and contribution to the ERIA team.

I also appreciate the excellent contribution of the ERIA team in conducting the study and preparing this report. A special thanks also goes to Setsuo Miyakoshi, linear programming and dynamic simulation expert, for his excellent contribution to this project.

Shigeru Kimura

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August 2020

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Abbreviations and Acronyms

CAPEX	capital expenditure
CBM	cubic metre
CCGT	combined cycle gas turbine
DS	dynamic simulation
DSLNG	Donggi Senoro LNG
FSRU	floating storage regasification unit
GPP	gas-fired power plant
GWh	gigawatt-hour
LNG	liquid natural gas
LP	linear programming
MEMR	Ministry/Minister of Energy and Mineral Resources
MMSCFD	million standard cubic feet per day
Mtoe	million tonnes of oil equivalent
MTPA	million tonnes per year
OPEX	operating expenses
PGN	Perusahaan Gas Negara (State Gas Company)
PLN	Perusahaan Listrik Negara (State Electricity Company)
PLTG	Pembangkit Listrik Tenaga Gas (gas-fired power plant)
PLTMG	Pembangkit Listrik Tenaga Mesin Gas (gas engine power plant)
RUKN	National Electricity Plan
TCF	trillion cubic feet
TWh	terawatt-hour
US$	United States dollar

Executive Summary

Electricity demand in Indonesia has been growing rapidly at a rate of 8.1% per year from 1990–2015 and will continue at a slightly lower rate of 6.2% per year in 2015–2040, according to the East Asia Summit (EAS) energy outlook prepared by the Economic Research Institute for ASEAN and East Asia (ERIA) (2019). As a result, the share of electricity per total final energy consumption is forecast to increase from 10.6% in 2015 to 16.3% in 2040. The increase in electricity will occur not only on large islands such as Java (Jakarta) and Sumatra (Medan) but also on the small and midsized Islands of Indonesia. The eastern part of Indonesia, which is surrounded by Kalimantan, Sulawesi, Papua, and Nusa Tenggara islands, comprises many small and midsized islands whose population share was 16% of the total Indonesian population in 2017. Due to the continuous growth of the population in this area, electricity demand is expected to increase up until 2040. The current operation of three production sites of liquefied natural gas (LNG) – Bontang, Donggi, and Tangguh – and one planned LNG site, Masela, would be an opportunity to shift from diesel oil, the main fuel source of the small and midsized islands, to natural gas for power generation. Such a shift would reduce the high fuel costs of diesel oil and carbon dioxide emissions in this area. However, the economical delivery of LNG from its production sites to demand sites needs to be studied.

To analyse the issue, this study applied two approaches: (i) linear programming (LP) – to find an optimal LNG flow between origins and destinations, and (ii) dynamic simulation (DS) – to simulate LNG delivery operation on a personal computer based on LNG demand and supply information. The DS extracts the appropriate size of LNG storages and appropriate size and number of LNG tankers. For the DS, the simulation conducted through manipulation of several parameters encompasses the size of LNG storage, its initial volume, storage level for LNG tankers, the size of LNG tankers, and distance information between origins and destinations, including the average speeds of LNG tankers.

Based on the LP approach, demand sites totalling 18 in this area are divided into four groups: Bontang, Donggi, Masela, and Tangguh. After that, three case studies of the DS were undertaken in each group. The key findings from the DS are as follows:

1) There are two LNG delivery methods: hub & spoke and milk run. Hub & spoke delivers LNG to a specific island per navigation whilst milk run delivers LNG to several islands per navigation.
2) The milk-run method entails a high operation rate of LNG tankers because of the smaller number of LNG tankers required. In other words, the idling time of LNG tankers is reduced. Hence, the milk-run method is economically recommended as an LNG delivery method in this area.
3) However, the milk-run method does not contribute to the reduction of LNG storage costs; occasionally, the method needs a bigger size of LNG storage to avoid lack of LNG shortage delivered.

4) Thus, more precise DS will be needed to seek more realistic solutions to both LNG storages and tankers using more reasonable parameters of the DS.

This study respects Indonesia' current LNG policy, which is LNG export at Bontang LNG – the limited amount of LNG is delivered to LNG domestic demand sites near Bontang. Several big LNG demand sites near Bontang are Bali, Lombok, Palu, and Makassar. One policy recommendation is a swap of the export role between Bontang and Tangguh because Tangguh is quite far from the main LNG demand islands in this area.

Case 3 applying the milk-run method shows the lowest cost amongst the cases. Its LNG delivery cost is around US$55–US$77 per tonne, a cost level that is higher still than the international LNG trade price of US$50–US$70 per tonne of Japan's LNG CIF (cost, insurance, and freight) in 2018 until the first quarter of 2020 because the LNG delivery cost does not include its production cost. The capital expenditure (CAPEX) of LNG storages accounts for half of the total costs – thus, the following policy is recommended. There are 18 sites that have diverse electricity demand in this area, and this study assumes all the sites will shift to natural gas generation. However, there are only eight of the big electricity demand sites with more than 500 million tonnes of LNG per year. Hence, shifting to gas power plants can be done only in the case of eight sites, such as Bali, Lombok, and Halmahera. The remaining sites apply other power systems such as a combination of diesel power plants and solar PV (photovoltaic) system, together with microgrid technology.

Gas has a big advantage over coal in generating power as it is easy to control the output level. Thus, a combination of gas power generation and renewable energy electricity, such as a solar and wind power system, will be a more suitable option for Indonesia, especially on small and midsized islands. Thus, seeking an optimal LNG delivery system under an affordable power generation mix with gas power generation will be crucial in for the future.

Chapter 1

Introduction

The electricity demand of Indonesia will increase significantly about 4.5 times from 2017 to 2040 under a business-as-usual scenario (Malik, 2019). The report mentioned that coal share in power generation will remain dominant in the total power generation of the country. In 2015, coal share in power generation reached almost 56%, higher than that of oil. This share is expected to continue to increase in the future, reaching around 70% in 2040.

At 47%, oil had the largest share in power generation in 1990. By 2015, the share of oil declined to around 8.4% as production from coal and natural gas plants increased rapidly. In the business-as-usual scenario, the share of oil in 2040 will be less than 3%. The use of diesel fuel in the small-scale off-grid diesel-fired and dual-engine (diesel fire and natural gas) power plants currently constitutes most of the electricity generation system in the eastern Indonesian islands.

In the business-as-usual scenario, the Secretariat General National Energy Council (DEN, 2019) foresaw that Indonesian gas supply in 2050 would reach 167.4 Mtoe (million tonnes of oil equivalent), i.e. an increase of three times from 2018 whilst gas production would decline from 75.4 Mtoe in 2018 to 66.3 Mtoe in 2050. Looking at this gap between the needed demand and production capacity, the Government of Indonesia shall prioritise meeting the domestic demand by not making a new contract on gas export with foreign stakeholders and by not extending the existing contracts.

The government has set a strategy to increase the use of natural gas in power generation. The decision of the Ministry of Energy and Mineral Resources (MEMR) Decree 13 K/13/MEM/2020 (MEMR, 2020e) issued in January 2020 mandated the state oil and gas company Pertamina to establish liquefied natural gas (LNG) supply within 2 years to support the conversion of 52 power plants from diesel fuel to natural gas. This conversion concerns a total installed capacity of 1,697 MW and shall need 166.98 billion BTU (British thermal unit) of natural gas per day. In April 2020, the MEMR issued Minister Decision No. 91 K/12/MEM/2020 that set the feed-in-tariffs of natural gas to be used in power plants (MEMR, 2020d).

The study aims to analyse the opportunities to develop LNG-based electric power generation systems in midsized and large islands of Indonesia by identifying the possible configuration of small-scale LNG supply chain. This will contribute to stable electric power supply and provide affordable electricity in those islands in a sustainable way in coherence with the national development plan.

The study is also consistent with the strategic theme of the ASEAN Economic Community Blueprint 2025 and its subordinate paper, the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016–2025 phase 1. It shall contribute to the regional energy policy and planning objective, namely, to enhance the integration of energy policy and planning, and that of the ASEAN Council on Petroleum framework.

This report starts with an update of the government's policies on the development of LNG in chapter 2, followed by a forecast of its demand, assuming the current diesel-fired power generation plants in eastern Indonesia's small islands will be replaced by gas-fired plants (chapter 3). Chapter 4 discusses how the location of the potential LNG-receiving ports are being determined in eastern Indonesia's islands, considering the potential LNG demand and port accessibility based on the profile of ports and LNG carrier vessels. This is followed by the estimate of LNG production to meet the demand, especially in Bontang, Donggi, Masela, and Tangguh (chapter 5). Chapters 6 and 7 present the results of static and dynamic simulations of LNG delivery by LNG carrier vessels from the production sites to the receiving ports in eastern Indonesia's small islands.

Chapter 2
Indonesia's LNG Policy

1. Outlook of Natural Gas in Indonesia's Energy Mix

Natural gas plays an important role in meeting Indonesia's energy demand. Under Presidential Regulation No. 22/2017 concerning the National Energy General Plan, energy supply will come from various energy sources mix with the following shares:

1) New low-carbon energy sources and renewables – at least 23% in 2025 and 31% in 2050
2) Oil – less than 25% in 2025 and less than 20% in 2050
3) Coal – at least 30% in 2025 and 25% in 2050
4) Gas – at least 22% in 2025 and 24% in 2050

The report of the Asia Pacific Energy Research Centre (APERC) on APEC Energy Supply–Demand Outlook 2019 (APERC, 2019) projected the growth of Indonesia's gas demand for meeting domestic and export commitment from 58.8 Mtoe in 2020 to 60.9 Mtoe in 2040 (Table 2.1). Gas demand in electricity will continuously dominate, accounting for 30% in 2020 and growing to 40% of total gas demand. Industry accounts for the second-largest gas consumer. Indonesia will maintain export gas. However, the volume will decrease significantly to 44 Mtoe in 2035. In 2040, Indonesia is projected to import natural gas to meet domestic demand.

Table 2.1: Indonesia Gas Demand Outlook (Mtoe)

	2020	2025	2030	2035	2040
Total gas demand (Mtoe)	58.8	54.3	55.8	59.7	60.9
Electricity	18.0	17.1	19.1	24.8	33.1
Energy Industry (Owned Used)	3.4	3.8	4.2	4.6	4.9
Transport	0.1	0.3	0.7	1.1	1.6
Building	1.2	1.6	2.1	2.8	3.4
Non energy use	3.4	3.8	4.2	4.6	4.9
Industry	11.8	13.8	15.8	17.5	19.0
Exports	20.9	13.7	9.6	4.4	-6.0

Mtoe = million tonnes of oil equivalent.
Source: APERC (2019).

Government Regulation No. 79/2014 on the National Energy Policy directed the role of natural gas in Indonesia's energy supply (Government of Indonesia, 2014). Projected demand for natural gas until 2050, per the National Energy Policy, will grow from 1.84 TCF (trillion cubic feet) in 2015 to 3.29 TCF in 2025 and to 9.21 TCF in 2050 (Table 2.2). The average growth of natural gas demand from 2015 to 2020 is 6% per year; 2020–2025, 7% per year; 2025–2030, 5% per year; 2030–2040, 5% per year; and 2040–2050, 3% per year. The demand for natural gas will increase significantly from 2015 to 2025 (6%–7% per year). During that period, the government will optimise the use of gas for domestic use both as fuel and industrial raw material to create higher added value and as a transition to the use of cleaner technologies, such as new energy and renewables.

Table 2.2: Projected Gas Demand of Indonesia

Year	2015	2020	2025	2030	2040	2050
Gas Demand						
Share (%)	22	22	22	23	24	24
Volume (Mtoe)	47	64	84	110	178	235
Volume (TCF)	1.84	2.51	3.29	4.31	6.98	9.21
AAGR (%)		6	7	5	5	3

AAGR = average annual growth rate, TCF = trillion cubic feet.
Source: Government of Indonesia (2014).

2. LNG Role in Indonesia's Energy Supply

Indonesia is a pioneer in the LNG industry. The country started the LNG industry in the early 70s. The construction of LNG Plant Arun train 1/2/3 and LNG Plant Bontang train A/B started in 1974, each with a capacity of 1.7 MTPA (million tonnes per annum). The first LNG was shipped to Japan from LNG Badak in 1977, followed by LNG Arun in 1978. The available market in East Asia encouraged Indonesia to rapidly expand the LNG plant capacity. LNG Arun doubled to six trains with a total capacity of 12.5 MTPA. Bontang was expanded to eight trains, processing 22.5 MTPA at its peak production. Indonesia built two more LNG plants: LNG Donggi Senoro with a capacity of 2 MTPA and Tangguh LNG plant, with 7 MTPA. Donggi Senoro LNG delivered its first LNG in 2015 and Tangguh in 2009. Indonesia is currently developing two more LNG plants, Tangguh Train III and Masela.

Natural gas has supplied domestic energy demand, fuelled power plants, and used in the industry and commercial sectors as well. However, due to geographical conditions, Indonesia, being an archipelagic country, faces several challenges in transporting gas to consumers. Most gas fields in Indonesia are located in less-developed areas, far from consumers. To transport natural gas from the gas field to consumers, Indonesia has developed natural gas infrastructure consisting of transmission and distribution lines. The current natural gas infrastructure comprises 5,254 km transmission lines; 6,183 km distribution lines; and 3,438 km city gas pipelines. In 2020, 13 companies were active in transmitting natural gas and 30 companies are involved in distribution. However, only PT Pertamina Gas and Perusahaan Gas Negara (PGN) (State Gas Company) then merged as Pertamina's Sub-holding that plays a major role in both transmission and distribution.

Domestic use of LNG in Indonesia started when the government decided to allocate LNG to overcome the gas supply shortage in West Java in 2010. PT Nusantara Regas, a joint

Pertamina and PGN subsidiary, constructed the Floating Storage Regasification Unit (FSRU) with a storage capacity of 3 MTPA and regasification capacity of 500 million standard cubic feet per day (MMSCFD), and stationed in Jakarta Bay. The LNG ship Aquarius, with a capacity of 125 CBM, has been delivering LNG from the Badak and Tangguh LNG plants since 2012, and from Donggi LNG plant since 2016. The main LNG consumers are power plants owned by the Perusahaan Listrik Negara (PLN) (State Electricity Company): Muara Karang, Tanjung Priok, and Muara Tawar.

The government issued a licence for the construction of the second FSRU in Medan in 2012. However, since the government converted the Arun LNG plant to an LNG receiving, storage, and regasification terminal, the FSRU operated by PGN relocated to Lampung and started its operation in 2014. FSRU Lampung measures 294 metres in length and 46 metres wide. It stores LNG 170,000 CBM and regasifies 240 MMSCFD of LNG.

Due to declining gas resources, after having exported 4,269 cargoes of LNG since 1978, the government closed the Arun LNG plant in May 2014. The government decided to convert the plant into a storage and regasification terminal to supply industry in Aceh and North Sumatra in 2015. The total regasification facility operated by PT Perta Arun Gas is 450 MMSCFD. The facility supplies LNG to PLN with 105 MMSCFD for the fuelling power plants in Arun and Belawan. Gas to Belawan is transported through 350 km with a 24-inch diameter pipeline which could deliver 250 MMSCFD gas. LNG supply for the Arun Storage and Regasification Facility is generated from Bontang, Donggi, and Tangguh. In 2019, Perta Arun Gas expanded its Arun facility as a hub for international LNG trade by renting its LNG storage capacity to the international LNG trader.

Currently, Indonesia is waiting for the commissioning of the fifth LNG storage and regasification facility in Teluk Lamong, East Java. At the initial stage of operation, the facility will use offshore storage and regasification unit capable to handle regasification at 180 MMSCFD. At the final stage, the facility will use a land-based fixed LNG tank with a capacity of 50,000 CBM, constructed in a 2.5-hectare land; it is expected to be ready by 2023. The regasification facility is expected to be expanded to provide a maximum of 600 MMSCFD regasification capacity in the future. The facility is equipped with a small-scale LNG filling terminal to fill an ISO tank of 20 feet by 40 feet, which will be transported to consumers in East Java Region.

Indonesia has transported LNG using truck-mounted ISO tank 12 feet to supply the power plant at Semberah located 70 km from the Badak LNG plant. LNG is transported from Bontang via ISO tanks and stored at six 105 CBM LNG tanks. LNG is regasified at 7.9 MMSFD to fuel a 2 x 20 MW gas power plant. Twenty ISO tank trucks are dedicated to transport LNG.

To meet domestic energy demand, LNG is also used for transportation and commercial fuel. Pertamina conducted a trial test of LNG used to fuel trucks in Balikpapan in 2014. Some LNG-fuelled trucks were being used by mining companies in East Kalimantan recently. In addition, LNG transported in ISO tanks has supplied industries in North Sumatra, East Kalimantan, South Sulawesi, and South-east Sulawesi. Private companies will supply LNG to hotels in West Java, Bali, and other regions.

In June 2020, the government, through an MEMR decree, established a task force on energy utilisation and energy security whose task is to increase LNG consumption in the industry, household, and transport sectors, especially the shipping industry. The task force was mandated to secure the construction of LNG terminals in West and Central Java. Following the decree, Pertamina started trying out the Anchor Handling and Tug Supply ship to support offshore oil and gas in East Kalimantan. To enable LNG consumption, the ship was converted to diesel dual fuel with fuel combination LNG: high-speed diesel is 60:40. LNG was supplied to the ship via ISO tanks. The commercial use of LNG to fuel ships will start in August 2021. The government is also seriously considering the use of LNG for rail transport.

3. Small-Scale LNG Terminal

The Government of Indonesia issued the National Gas Policy Road Map 2014–2030 in 2014. This policy proposed that small-scale LNG infrastructures supply gas to the small islands in East Indonesia. Indonesia started its first mini LNG terminal at Benoa Bali in April 2016. The LNG terminal operated by Pelindo Energi Logistik intended to supply gas to a 250-MW power plant in Pesanggrahan, Bali at 40 MMSCFD rates. The LNG facility consists of two main infrastructures, namely, the floating regasification unit (FRU) and the floating storage unit (FSU). FSU Hysy and FRU were both rented and moored alongside the Pelindo wharf at Benoa Bay. LNG from Badak was stored at the FSU, sent to the FRU located next to the FSRU for regasification, then piped to the PLN power plant in Pesanggrahan. The total investment reported was US$500 million. In addition to supplying the power plant in Pesanggrahan, the terminal also aimed to supply cooling water to Ngurah Rai Airport, located 6 km from the terminal site.

After almost 3 years of operations, Pelindo Energi Logistik decommissioned the FSU and FRU unit and installed a new FSRU, namely, Karunia Dewata in December 2018. The FSRU is equipped with four independent C-type LNG tanks, each with a capacity of 6,500 CBM or 26,000 CBM in total. The FSRU regasifies LNG at 50 MMSCFD and sends the gas to Pesanggrahan power plants.

4. Regulatory Framework

Gas distribution in Indonesia is regulated by the following: (i) Law No. 22/2001 regarding oil and gas law and its derivatives, (ii) Government Regulation No. 36/2004 concerning the Oil and Gas Downstream Business, and (iii) MEMR Regulation No. 4/2018 regarding the Downstream Gas Business to Accommodate LNG as a Mode of Transport of Gas for the Domestic Market and Prohibit Multilevel Gas Trading, which replaced the previous MEMR Regulation No. 19/2009 concerning the Natural Gas Business through Pipelines. Indonesia's gas regulatory framework promotes unbundling business models, whereby upstream companies are prohibited from taking part in the downstream business, and vice versa.

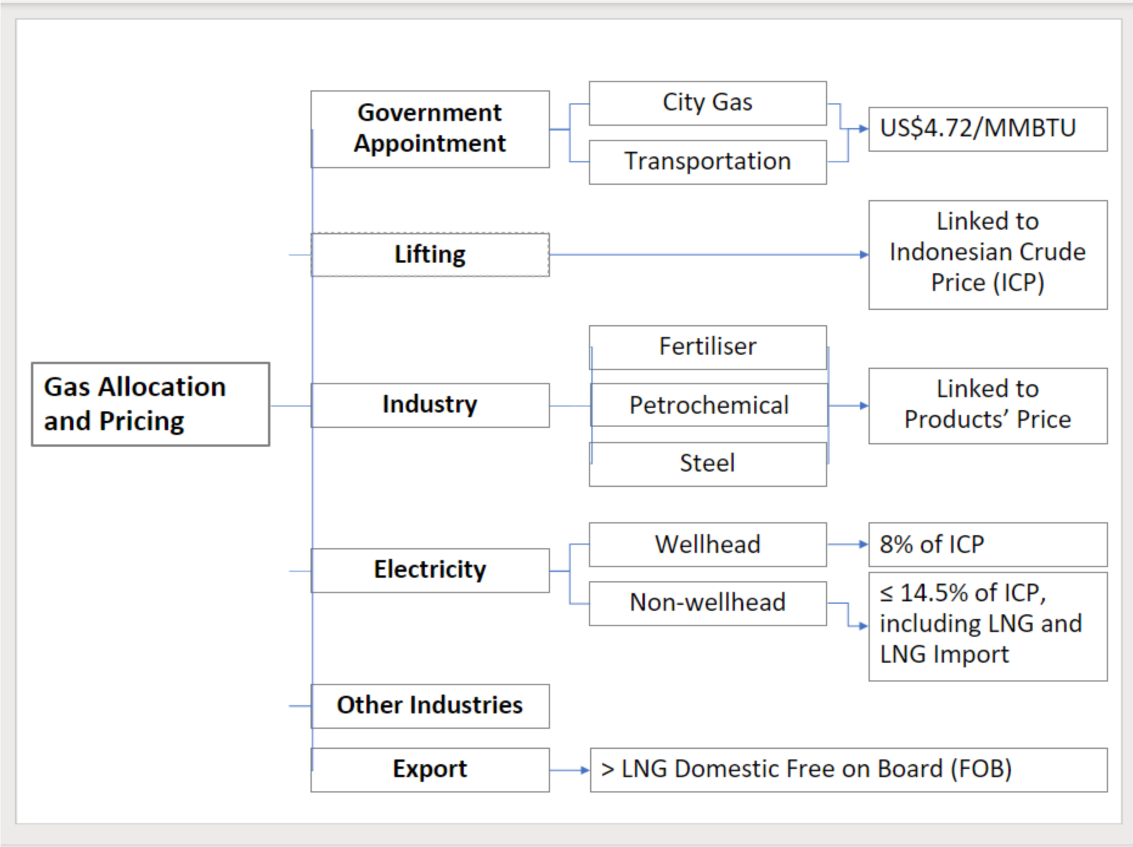
Article 8 no. 3 of Law No. 22/2001 provides that transport business activities of natural gas connected through pipelines shall be regulated so that their utilisation is open for all. The law allowed the private sector to build and operate gas pipelines. The natural gas business framework in Indonesia adopts retail competition. However, the majority of pipelines built before the enactment of Law No. 22 of 2001 were project-specific point-to-point pipeline, their capacity was not prepared to transport a large volume of gas, have various specifications, and were challenging for interconnection. Only part of the transmission lines are open for third-party access, whilst most distribution companies still operate in monopoly. Geographical conditions also mismatch with infrastructure, gas resources, and consumers in some circumstances, encouraging gas sellers or traders or consumers to build their pipelines. As a result, the implementation of the open access policy and competition is yet to be effective.

Currently, 38 companies have entered the market and are involved in the downstream gas business. However, only 10 firms that entered the gas market own the infrastructure – they built pipelines to distribute gas – whereas Pertagas and PGN are the dominant players. The rest of the companies only act as pure traders. These pure trader companies have added more layers in gas transactions, leading to cost inefficiency.

The MEMR issued Minister Regulation No. 6/2016 concerning the provisions and procedures for determining the allocation, utilisation, and price of natural gas. Under this regulation, the government encourages gas trading between producers and direct consumers and abolished pure trader companies to reduce the gas price for consumers. Besides, the regulation also encourages optimisation and utilisation of gas as a driver of economic growth.

In 2016, the government introduced economic stimuli to enhance economic growth. One is a policy to maximise gas for national development and is provided to certain industries. Under this policy, companies in which gas is 40%–50% part of their cost structure are to receive gas supply with a special price of US$6.00/MMBTU (million British thermal unit). The industries listed to receive incentives are oleochemical, fertiliser, petrochemical, steel, ceramic, glass, and gloves. To meet the gas price target, the government subsidised gas from shared revenue generated by the upstream gas fields. In addition, the government also adjusted toll fees, considered an appropriate normal return on investment in midstream business. Gas pricing mechanism for those industries, which were subsidised, is regulated by MEMR Regulation No. 40/2016 on gas pricing for certain industries. Under this regulation, gas prices for fertiliser and petrochemical are linked to the price of urea and ammonia. For the steel industry, gas prices are linked to hot rolled coil. The scheme of regulation is elaborated in Figure 2.1.

Figure 2.1: Gas Allocation and Pricing Policy



Source: MEMR Regulation No. 40/2016 and MEMR Regulation No. 8/2020.

MEMR Regulation No. 40/2016 concerning gas pricing for certain industries was amended by MEMR No. 8/2020 (MEMR, 2020a) which sets the maximum gas price of listed industries at US$6.0/MMBTU at plant gate. The details of pricing for industries were set by the Ministry of Energy and Mineral Resources (MEMR) Decree 89 K/10/MEM/2020 regarding Consumers and Price of Natural Gas for Industry. Prices are adjusted such that these would not economically jeopardise the upstream companies. The government provides subsidy from its share in the related gas fields. Government assigned Pertamina to supply gas to industries through Decree 90 K/10/MEM/2020 regarding Appointment of PT Pertamina (Persero) to Deliver Gas to Industrial Consumers.

For power generation, the gas price is regulated under MEMR No. 11/2017 concerning gas for power plant pricing, which was amended by MEMR Regulation No. 45/2017. The latest amendment was by MEMR Regulation No. 10/2020, which sets the maximum price of gas for power generation at US$6.0/MMBTU. The price of wellhead gas and mine mouth power plant gas is 8% Indonesian crude price.

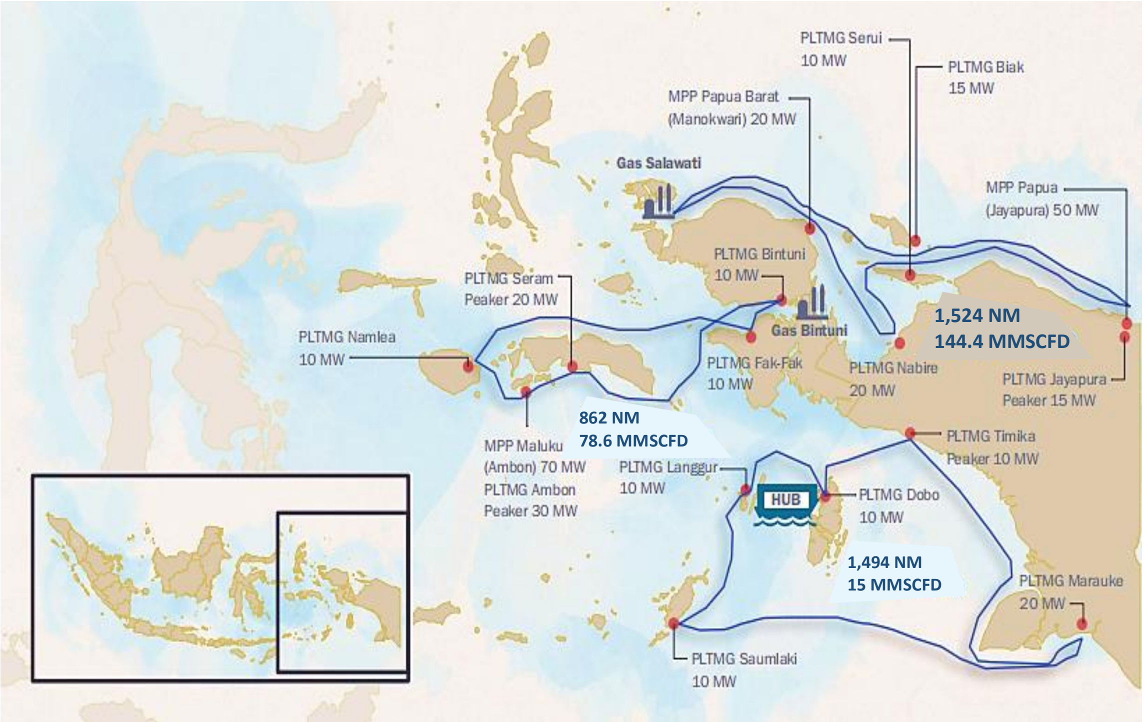
The price of downstream gas (gas transported) through pipeline is determined by MEMR Regulation No. 58/2017 (MEMR, 2017a) regarding the price of natural gas transported through pipelines. The final price of natural gas for consumers is determined by the wellhead gas price, infrastructure cost, and trading fee. Wellhead gas price is determined by gas fields' economic development and is negotiable. The infrastructure costs include transport and distribution, liquefaction, compression, regasification, and storage. The government sets up a formula for calculating the cost of infrastructures. The internal rate of return (IRR) of infrastructure was set at 11% for developed markets and 12% for underdeveloped markets. For IRR calculation, the government used the assumption that 60% of the capacity of infrastructure was used and the lifetime of the infrastructure at 15 years for new infrastructure. For pipeline/infrastructure that exceed 15 years, the lifetime is calculated based on the designated remaining life of the infrastructure in operation. Trader cost is set at 7% of gas price.

5. Future LNG Development Policy

Due to their nature, most power plants in Eastern Indonesia are powered by oil.

However, since LNG technology currently enables the transport of LNG in small volume, the government issued a policy to convert oil into LNG to generate power in the area. The implementing policy crafted in MEMR Decree No. 13 K/13/MEM/2020 (MEMR, 2020e) concerning assignment of the construction of LNG infrastructure in Eastern Indonesia, conversion of fuel oil into LNG to supply electricity, and securing LNG supply. The decree assigned Pertamina to build LNG storage and regasification infrastructures to convert 52 power plants in Eastern Indonesia, with a total LNG demand of 170 billion BTU per day. An early process to implement the policy is taking place.

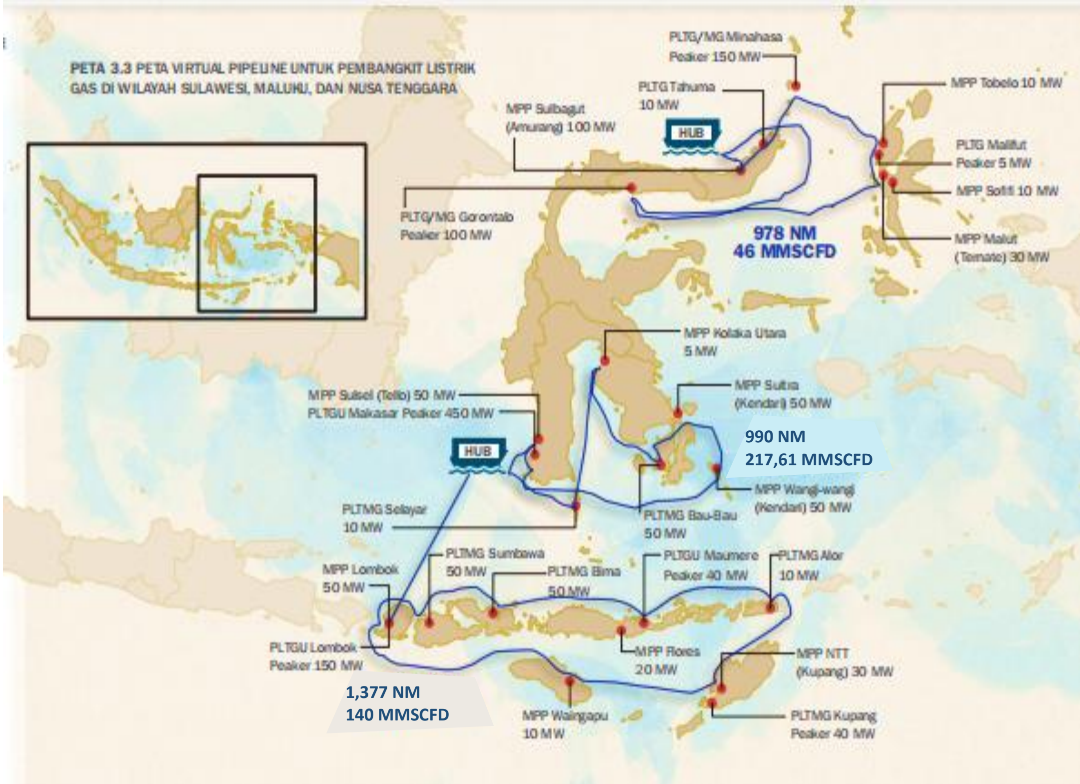
Figure 2.2: Proposed Natural Gas Plant in Papua and Maluku



Source: MEMR (2015).

Indonesia will develop a 9 MTPA capacity LNG plant in Masela. The role of LNG to meet domestic energy demand will continuously increase. Indonesia will also be an LNG hub as indicated by the opening of the Arun terminal to store LNG owned by overseas companies. Declining gas in East Kalimantan will reduce the operation of LNG Badak. LNG Badan plant will most likely be converted into an LNG storage and regasification facility either partially or completely if LNG production ceases. It has a similar path to that of the Arun LNG plant.

Figure 2.3: Proposed Gas Power Plant in Sulawesi, Bali, and Nusa Tenggara



Source: MEMR (2015).

The utilisation of LNG to meet future energy demand will increase. Per experience in operating the FSRU, the regasification unit will provide a good learning curve in maximising LNG infrastructure development and use to meet Indonesia’s energy demand and the national goal of reducing emissions from the energy sector.

6. Conclusion

The Government of Indonesia sees that LNG is an important source of energy for fuelling the economy and securing the energy supply of the country. Several policies encourage optimisation of gas supply in the country, such as pricing policy, incentives for infrastructure development, and facilitation of accurate business policies that bring natural gas to consumers.

Chapter 3

Forecast of LNG Demand in Eastern Indonesia

This study focuses on delivering LNG in Eastern Indonesia to meet the requirement of natural gas–fired power plants (GPPs). It covers the eastern part of Indonesia and the provinces listed in Table 3.1. Kalimantan provinces are excluded because the requirement of GPPs will be met internally through pipelines. This chapter projects electricity demand for the designated area, and based on this, forecast LNG demand.

Table 3.1: Provinces Covered in the Study

No.	Province
1	North Sulawesi
2	Gorontalo
3	Center Sulawesi
4	Southeast Sulawesi
5	West Sulawesi
6	South Sulawesi
7	Maluku
8	North Maluku
9	Papua
10	West Papua
11	Bali
12	East Nusa Tenggara (NTT)
13	West Nusa Tenggara (NTB)

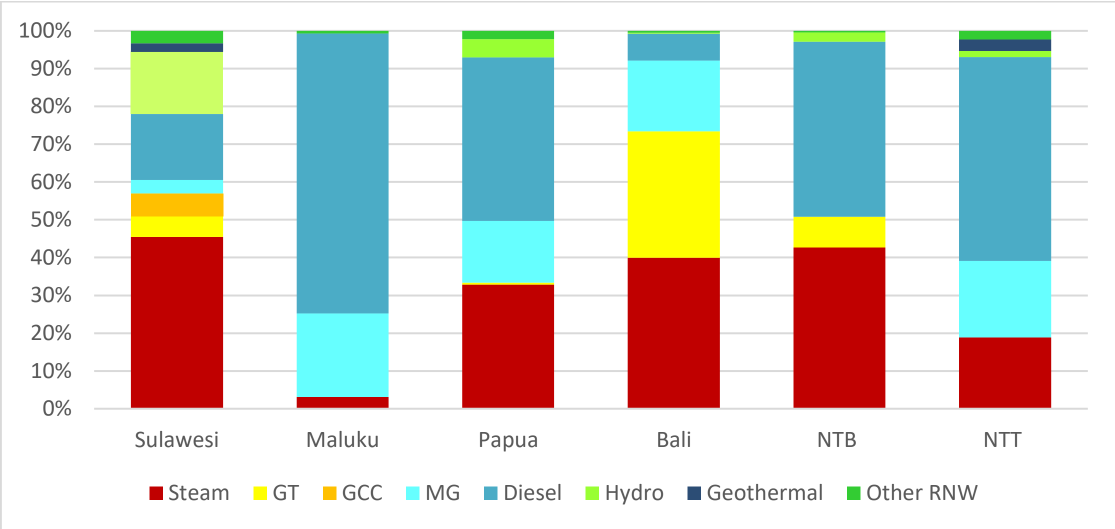
Source: Authors' calculation.

1. Current Situation

Indonesia's electricity consumption was 234.6 gigawatt-hour (GWh) in 2018 according to the Directorate General of Electricity (2019). Most of this consumption was from the residential (42%) and industry (33%) sectors. By region, Java electricity consumption accounted for about 71% of the total consumption, and Eastern Indonesia shares were 9%. These are the consumption of Sulawesi, Maluku, North Maluku, Papua, West Papua, Bali, West and East Nusa Tenggara (NTB and NTT).

Electricity supply of these regions mostly came from diesel power plants, around 71%, whilst steam and hydro power plants accounted for around 15% and 8%, respectively. The remaining supply are from GPPs, solar, wind, and geothermal. Figure 3.1 shows the distribution of power plants in the designated Eastern Indonesia regions.

Figure 3.1. Plant Capacities in Eastern Indonesia, 2018



NTB = West Nusa Tenggara, NTT = East Nusa Tenggara, GT = gas turbine, GCC = gas combined cycle, MC=machine gas, RNW=renewable
Source: Directorate General of Electricity, Indonesia (2019).

Recently, the MEMR issued Ministerial Decree No. 13 K/13/MEM/2020, mandating PT PLN, the State Electricity Company, to convert the 52 diesel power plants to gas. The programme's purpose, as noted in the decree, is to reduce the trade deficit and to support the energy diversification programme. The conversion from diesel to gas would reduce PT PLN's diesel consumption from 2.6 million kilolitres (kL) per year to 1.6 million kL per year, with estimated operational cost savings at Rp4 trillion (US$286 million).[1]

The ministry also assigned the state-owned oil company, Pertamina, to supply the gas. This includes the development of the LNG infrastructure to receive, store, and regasify LNG. PT Pertamina is obligated to set the price of the regasified gas at 'plant gate', which will result in a lower production cost of PT PLN compared to using high-speed diesel.

Of the total 52 diesel plants in the decree, 32 plants are in Eastern Indonesia with a total capacity of 801 MW. Table 3.2 shows the total capacity of the diesel plants in said region to be converted into gas.

[1] Assumption: US$1.00 = Rp14,000.

Table 3.2: Total Diesel Plants Converted to GPPs in Eastern Indonesia

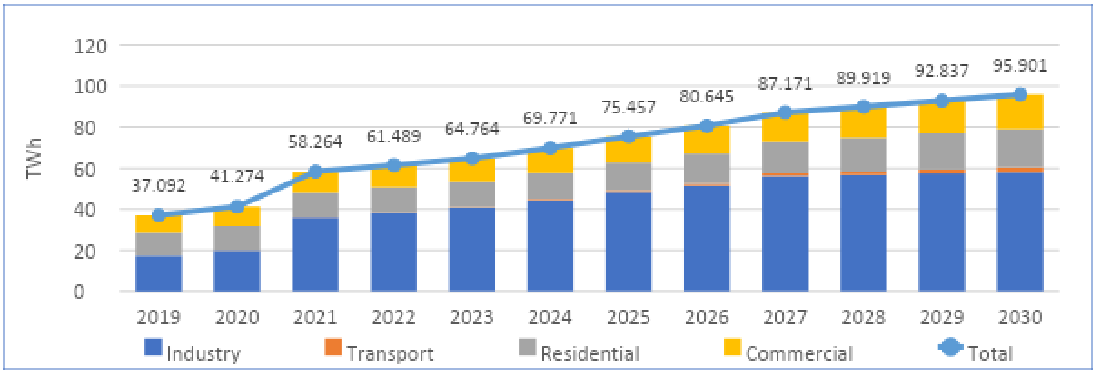
Province	Capacity (MW)
NTB (West Nusa Tenggara)	150
NTT (East Nusa Tenggara)	123
North Maluku	100
Maluku	110
Papua	100
West Papua	20
Gorontalo	100
Southeast Sulawesi	98
Total	**801**

Source: MEMR (2020e).

2. Electricity Demand Forecast

Electricity demand will continue to increase, and total electricity demand of Indonesia is projected to reach 638.8 terawatt-hours (TWh) by 2030, growing at an average rate of 7.5% per year over the 2019–2030 period. This electricity projection is from the National Electricity Plan (RUKN) 2019–2038 (MEMR, 2019). The RUKN projected electricity demand by province based on the population and GDP growth rate of each region and on the existing plan of the processing plants of mineral and mining companies. The electricity demand for these processing plants were included in the projection because the government had issued mineral laws that mandated companies to build processing plants before exporting the minerals. The mineral reserves are mostly in Eastern Indonesia, such as Sulawesi and Maluku Islands. Figure 3.2 shows the projected total electricity demand in the covered provinces of the study by subsector.

Figure 3.2: Electricity Demand Projection in Eastern Indonesia (TWh)



TWh = terawatt-hour
Source: MEMR (2019a).

The total electricity demand of the region will grow at an average of 9% per year, reaching almost 96 TWh by 2030. The region's demand is 15% of the national projection but the growth is faster. The industry sector will dominate the electricity demand of the region (61% in 2030) and the demand is projected to grow at an average rate of 11.6% per year over the 2019–2030 period. The residential sector's share (19%) in the total demand will be slightly higher than the commercial sector (18%) in 2030.

The RUKN limits the electricity demand projection at the province level. Breakdown by the regency will be estimated in the study by assuming the same level of electricity demand per capita of the province. Thus, the regency level electricity demand is calculated using the formula:

$$ED_{ij} = POP_{ij} * EDC_j$$

where:

ED_{ij}	= Electricity demand of regency i in province j
POP_{ij}	= Population in regency iI in province j
EDC_j	= Average electricity demand per capita of province j

The average electricity demand per capita (EDC) of the province will be the RUKN electricity demand projection of the province divided by the projected population of the province. The population figures were obtained from the Badan Pusat Statistik (BPS) or central and provincial statistical agency. The population projection of the province was based on the population projection of the National Development Planning Agency (Bappenas), BPS, and United Nations Population Fund (UNFPA) (BPS, 2013). The population projection was done only at the province level. The regional population in 2030 was calculated using the existing regency shares to its province (2017 data). The resulting population by regency and the calculated electricity demand of these regencies was the basis for selecting the location of potential GPPs.

After discussion and considerations, the study selected locations in the provinces which can potentially build the combined cycle gas turbine (CCGT) and demand in 2030 more than 100 GWh. These are three locations on the island of Sulawesi, one location in Bali Island, two locations in each province of NTB, NTT, Maluku, North Maluku, West Papua, and four locations in Papua. Table 3.3 shows the selected locations of the provinces, their population, and the total and per capita electricity demand.

Table 3.3: Electricity Consumption, 2030

Region		Total Population	Electricity Consumption	Electricity per Capita
		People	GWh	KWh/capita
North Sulawesi		2,696,228	6,719	2,492
Center Sulawesi		3,480,252	14,892	4,279
South Sulawesi		7,486,185	16,799	2,244
Bali		4,765,261	9,602	2,015
West Nusa Tenggara		5,581,818	5,219	935
1	Lombok	3,913,290	3,659	
2	Sumbawa	1,668,528	1,560	
East Nusa Tenggara		6,408,964	2,288	357
1	Flores Island	2,431,126	868	
2	Kupang/Timor Island	2,309,014	824	
Maluku		2,104,922	1,625	772
1	Buru	485,985	375	
2	Ambon	581,903	449	
North Maluku		1,499,436	13,282	8,858
1	Halmahera (South)	833,352	7,382	
2	Ternate	277,478	2,458	
Papua		3,937,992	4,001	1,016
1	Merauke	269,418	274	
2	Yapen Island (Serui)	114,583	116	
3	Biak	174,512	177	
4	Jayapura City	354,204	360	
West Papua		1,200,153	4,701	3,917
1	Manokwari	218,670	857	
2	Sorong City	885,726	3,469	

Source: Authors' calculation.

After selecting the potential locations, the next step was to identify the city where the harbour or port will be. Table 3.4 shows the city name and the abbreviations used for modelling purposes.

Table 3.4: Potential Location for CCGT

No.	Potential Location	City Name	Abbreviation
1	North Sulawesi	Manado	MND
2	Center Sulawesi	Palu	PAL
3	South Sulawesi	Makassar	MKS
4	Bali	Benoa	BNO
5	Lombok, West Nusa Tenggara	Lembar	LMB
6	Sumbawa, West Nusa Tenggara	Badas	BDS
7	Flores, East Nusa Tenggara	Labuan Bajo	LBJ
8	Kupang, East Nusa Tenggara	Kupang	KPG
9	Ambon, Maluku	Ambon	AMB
10	Buru Island, Maluku	Namlea	NLA
11	Halmahera (South), North Maluku	Weda	WED
12	Ternate, North Maluku	Ternate	TTE
13	Yapen Island, Papua	Serui	SRU
14	Biak, Papua	Biak	BIK
15	Merauke, Papua	Merauke	MRK
16	Jayapura, Papua	Jayapura	JAP
17	Manokwari, West Papua	Manokwari	MNK
18	Sorong, West Papua	Sorong	SON

CCGT = combined cycle gas turbine.
Source: Authors.

3. LNG Demand Forecast

3.1. Estimating electricity production from GPPs

The total electricity production in 2030 for the selected region (Table 3.5) was calculated as follows:

$$Production_i = Demand_i/(1-(OTD/100))$$

where:

$Production_i$ = Electricity production of location i
$Demand_i$ = Electricity demand of location i
OTD = Own use and transmission and distribution (T&D) losses

The own use and T&D losses for all selected regions were assumed to be 12.87%. This was the average of PT PLN figures in Indonesia.

Table 3.5: Electricity Production of Selected Regions in 2030

Potential Location	Electricity Demand	Own Use and T&D Losses	Electricity Production
	GWh	%	GWh
Center Sulawesi	14,892	12.87	17,092
South Sulawesi	16,799	12.87	19,281
North Sulawesi	6,719	12.87	7,712
Bali	9,602	12.87	11,020
Lombok, West Nusa Tenggara	3,659	12.87	4,199
Sumbawa, West Nusa Tenggara	1,560	12.87	1,791
Flores, East Nusa Tenggara	868	12.87	996
Kupang, East Nusa Tenggara	824	12.87	946
Buru Island, Maluku	375	12.87	431
Ambon, Maluku	449	12.87	516
Halmahera (South), North Maluku	7,382	12.87	8,472
Ternate, North Maluku	2,458	12.87	2,821
Yapen Island, Papua	116	12.87	134
Biak, Papua	177	12.87	203
Merauke, Papua	247	12.87	314
Jayapura, Papua	360	12.87	413
Manokwari, West Papua	857	12.87	983
Sorong, West Papua	1,232	12.87	1,414

T&D = transmission and distribution.
Source: Authors' calculation.

Currently, there are power plants existing to meet the electricity demand in the selected locations. The Electricity Supply Business Plan (RUPTL) of PT PLN 2019–2028 also includes the expansion of these power plants and the construction of new plants until 2028 (PLN, 2019). In addition to the planned capacity of the natural GPPs, the study assumed that the oil-based power plants in the selected region will be replaced by gas following MEMR Decree 13 K/13/MEM/2020. The coal steam power plants and renewable plants in 2030 will generate electricity based on the assumed installed capacity in the RUPTL 2019–2028 and the capacity factor shown in Table 3.6. Additionally, information on electricity production generated by coal and renewables is shown in Table 3.7.

Table 3.6: Capacity Factor of Power Generator (%)

Capacity Factor, %	
Coal	80
Hydro	65
Wind	45
Solar	15
Geothermal	85

Source: Authors' calculation.

Table 3.7: Electricity Production from Coal and Renewables (GWh)

Potential Location	Coal	Hydro	Biomass	Solar	Geothermal	Wind	Total
Center Sulawesi	14,962.78	1,262.47	0.00	0.00	0.00	0.00	**16,225.25**
South Sulawesi	6,937.92	10,295.61	105.47	6.95	0.00	559.76	**17,905.71**
North Sulawesi	4,316.93	704.01	122.64	1.76	893.52	0.32	**6,039.18**
Bali[a]	5,788.61	140.24	97.50	268.41	2,159.34	5.44	**8,459.54**
Lombok, West Nusa Tenggara	770.88	87.69	0.00	0.00	0.00	0.00	**858.57**
Sumbawa, West Nusa Tenggara	0.00	2.85	0.00	0.00	0.00	0.00	**2.85**
Flores, East Nusa Tenggara	98.11	4.56	0.00	0.00	74.46	0.00	**177.13**
Kupang, East Nusa Tenggara	441.50	1.14	0.00	1.31	0.00	0.00	**443.95**
Buru Island, Maluku	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Ambon, Maluku	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Halmahera (South), North Maluku	5,739.55	0.00	0.00	0.00	0.00	0.00	**5,739.55**
Ternate, North Maluku	280.32	0.00	0.00	0.00	0.00	0.00	**280.32**
Yapen Island (Serui), Papua	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Biak, Papua	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Merauke, Papua	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**
Jayapura, Papua	168.19	113.88	0.00	0.00	0.00	0.00	**282.07**
Manokwari, West Papua	84.10	17.65	0.00	0.00	0.00	0.00	**101.75**
Sorong, West Papua	0.00	0.00	0.00	0.00	0.00	0.00	**0.00**

[a] Bali's electricity production includes the interconnection from Jawa, which comes from coal plants.
Source: Authors' calculation.

Electricity generation from the GPPs is the difference between total electricity production in the selected location minus the generation from the coal and renewable power plants.

3.2. Calculation of LNG demand

The LNG demand for each selected region will be calculated based on the gas input for the natural GPPs. The gas input is calculated using the formula:

Input = Output/Plant Efficiency

The plant efficiency of GPPs is assumed to be 39%. The electricity output in GWh will be first converted to kiloton of oil equivalent (ktoe) using the following:

1 GWh = 0.086 ktoe

The natural gas requirements will be calculated using the conversion:

1 ktoe = 0.00111 billion m^3

The conversion of natural gas from billion m^3 to million tonnes of LNG will use the following factor:

1 billion m^3 = 0.714 million tonnes

The results of the LNG demand for the electricity generation of the GPPs is shown in Table 3.8.

Table 3.8: LNG Demand Forecast for the GPPs in the Selected Locations

Potential Location	Production from CCGT		Efficiency CCGT	Gas Consumption		LNG Consumption
	GWh	ktoe	%	ktoe	billion m^3	million tonnes
Center Sulawesi	1,415.54	122	39	312	0.35	0.247
South Sulawesi	1,313.47	113	39	290	0.32	0.230
North Sulawesi	1,096.97	94	39	242	0.27	0.132
Bali	2,968.18	255	39	655	0.73	0.519
Lombok, West Nusa Tenggara	2,598.92	224	39	573	0.64	0.454
Sumbawa, West Nusa Tenggara	1,474.94	127	39	325	0.36	0.258
Flores, East Nusa Tenggara	597.32	51	39	132	0.15	0.104
Kupang, East Nusa Tenggara	565.20	49	39	125	0.14	0.099
Buru Island, Maluku	430.60	37	39	95	0.11	0.075
Ambon, Maluku	515.59	44	39	114	0.13	0.090
Halmahera (South), North Maluku	2,596.93	223	39	573	0.64	0.454
Ternate, North Maluku	2,540.66	218	39	560	0.62	0.444
Yapen Island (Serui), Papua	133.61	11	39	29	0.03	0.023
Biak, Papua	203.49	18	39	45	0.05	0.036
Merauke, Papua	292.70	25	39	65	0.07	0.051
Jayapura, Papua	130.96	11	39	29	0.03	0.023
Manokwari, West Papua	88.31	76	39	194	0.22	0.154
Sorong, West Papua	1,413.54	122	39	312	0.35	0.247

CCGT = combined cycle gas turbine, GPP = natural gas–fired power plant, ktoe = kiloton of oil equivalent
Source: Authors' calculation.

Table 3.9 shows the LNG refilling for a large ship with a capacity of 13,500 tonnes.

Table 3.9: LNG Refilling Capacity for Large Ships

Potential Location	LNG Consumption		Refilling to Large Ship
	kiloton	t/day	Refill LNG/day
Center Sulawesi	152	415	32.52
South Sulawesi	240	659	20.50
North Sulawesi	292	801	16.85
Bali	448	1,227	11.01
Lombok, West Nusa Tenggara	584	1,600	8.44
Sumbawa, West Nusa Tenggara	313	856	15.77
Flores, East Nusa Tenggara	143	392	34.41
Kupang, East Nusa Tenggara	88	241	56.13
Buru Island, Maluku	75	206	65.45
Ambon, Maluku	90	247	54.66
Halmahera (South), North Maluku	478	1,309	10.31
Ternate, North Maluku	444	1,217	11.09
Yapen Island (Serui), Papua	23	64	210.94
Biak, Papua	36	91	138.50
Merauke, Papua	55	150	89.71
Jayapura, Papua	23	63	215.21
Manokwari, West Papua	55	422	31.98
Sorong, West Papua	247	677	19.94

Source: Authors' calculation.

Chapter 4
Selection of LNG Receiving Ports

In this chapter, we proposed the locations of LNG receiving ports by using a methodology that considers several factors. First, we looked at the forecasted LNG demand in Eastern Indonesia as estimated in chapter 3. Second, in each region we gathered all seaports that are geographically close to the existing or planned-to-be-developed natural gas–fired or dual-engine power plants. Third, we gathered information on the profile of those seaports. Finally, considering the specifications of the model LNG carrier vessels, we selected several seaports as LNG receiving ports based on the accessibility of those seaports.

In section 4.1, we presented the initial candidates for LNG receiving terminals (ports) based on the location of the existing seaports, the forecasted LNG demand and the existing and planned GPPs. In section 4.2, we selected LNG carrier vessels and presented their characteristics. Finally, in section 4.3, we presented the selected receiving ports based on their accessibility for the model ships.

1. Regions and the Potential LNG Receiving Ports

Chapter 3 identified 21 regions that include cities and small islands where potential LNG demand for power generation would likely be generated in the future, i.e. in the 2040 horizon. Table 4.1 summarises the results of demand forecasting, the potential seaports, the existing and planned gas-fired and dual-engine power plants, and the installed or planned-to-be-installed power generation capacity.

The existing seaports were selected as potential LNG receiving ports or terminals since they are currently serving the corresponding city or island as maritime ports. We also identified the existence of gas-fired and/or dual-engine power plants and/or plans to build and operate them in the near future. Several regions – South Halmahera, Flores Island, and North Sulawesi – have more than one potential seaport to serve as LNG receivers.

Table 4.1: Regions, Forecasted LNG Demand, Potential Seaports, and Natural Gas–Fired Power Plants

Location	Estimated LNG Demand 2030	Estimated LNG Demand 2040	Seaports	Existing and Planned Gas-Fired and Dual-Engine Power Plants	Installed or To-Be-Installed Capacity Megawatt (MW)
Center Sulawesi	1.87	2.27	Palu - Pantoloan	PLTG Palu (KEK - Special Economic Region/*Kawasan Ekonomi Khusus*)	200
South Sulawesi	4.22	8.44	Makassar New Port	PLTG Makassar Peaker – Tamalanrea	450
North Sulawesi			Bitung		
			Manado		
Bali	0.91	2.75	Benoa	PLTDG Pesanggaran	200
Lombok, West Nusa Tenggara	0.58	0.82	Lembar - Mataram, West Lombok	PLTG MPP Jeranjang Lombok	50
Sumbawa, West Nusa Tenggara	0.31	0.41	Badas - Sumbawa	PLTMG Sumbawa - Labuan Badas	50
Flores, East Nusa Tenggara	0.15	0.28	Labuhan Bajo	MPP Flores - Manggarai Barat	20
			Maumere	PLTMG Maumere - Sikka	40
Kupang, East Nusa Tenggara	0.09	0.21	Tenau - Kupang	PLTMG Kupang Peaker - Lifuleo (2018)	40
Buru Island, Maluku	0.08	0.10	Namlea	PLTMG Namlea (2020)	10
Ambon, Maluku	0.09	0.12	Ambon	PLTMG Ambon Peaker - Waai (2020)	30+70
Halmahera (South), North Maluku	1.48	1.55	Tobelo	PLTMG Mamuya Galela	30

			Tapaleo	PLTG Halmahera Timur	80
Ternate, North Maluku	0.44	0.47	Ternate Kota Baru	PLTMG Ternate Kastela	30
Yapen Island (Serui), Papua	0.02	0.05	Serui	PLTMG Serui	10
Biak, Papua	0.04	0.07	Biak	PLTMG Biak (2018)	35
				PLTMG Biak 2 (2019)	20
Merauke, Papua	0.05	0.11	Merauke	PLTMG Merauke Karang Indah	20
Jayapura, Papua	0.02	0.09	Jayapura	MPP Jayapura (2017)	50
				PLTMG Jayapura Peaker (2019)	40
				PLTMG Jayapura (2020)	50
Manokwari, West Papua	0.15	0.19	Manokwa ri	MPP Manokwari (2018)	20
				PLTMG Manokwari (2019)	20
				PLTMG Manokwari (2019)	20
Sorong, West Papua	0.25	0.30	Sorong	PLTG Sorong (2018)	30
				PLTG Sorong (2019)	20
				PLTMG Sorong (2025)	50

PLTG = gas-fired power plant, PLTMG = gas engine power plant, PLTDG = diesel and gas power plant, MPP = mobile power plant.
Source: Authors' estimation and calculation.

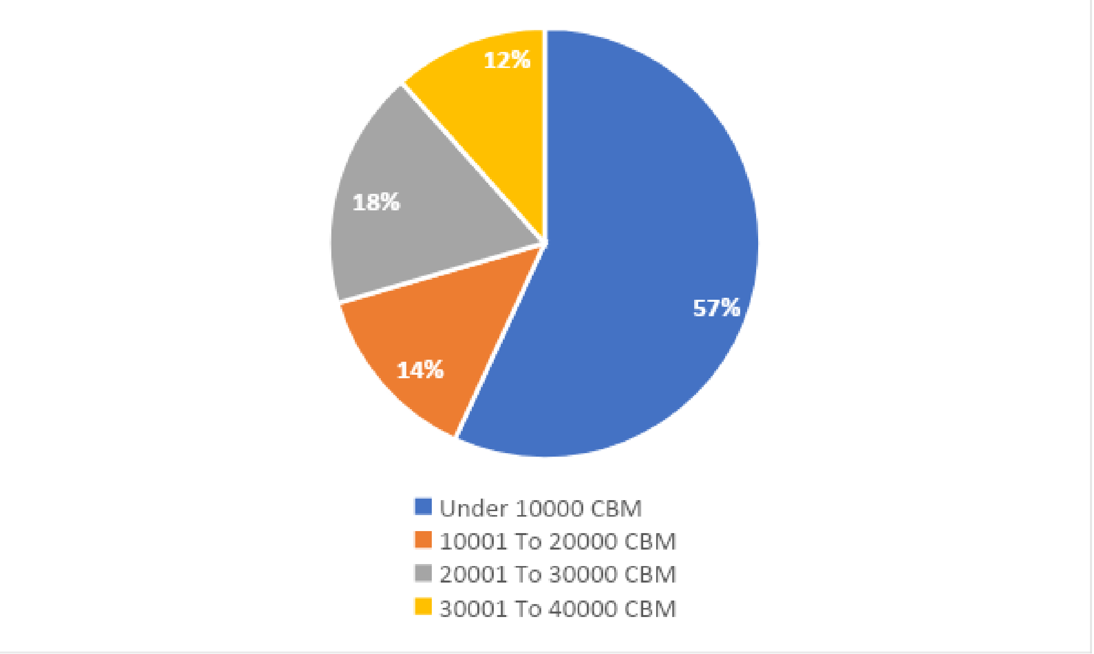
2. Small-Scale LNG Carrier Vessels

DNV-GL (2019) listed 96 small-scale LNG carrier vessels. From the different vessel information database available on the Internet[2], we collected information on the tanker size of 67 ships amongst the active ships. The maximum tanker size of the 67 ships is 36,000 cubic metres (CBM). We grouped the ships into four classes according to tanker size:

- Under 10,000 CBM
- 10,001–20,000 CBM
- 20,001–30,000 CBM
- 30,001–40,000 CBM

It appears that vessels with tanker size under 10,000 CBM make more than half of the total small-scale LNG fleet in the world and the percentage seems to decrease with tanker size (Figure 4.1).

Figure 4.1: Share of Small-Scale LNG Carrier Vessels According to Tanker Size



Source: Authors' calculation.

For each tanker size class, we selected one model vessel and assumed that their characteristics represent those of ships in the class.

Table 4.2 presents the five vessel–models based on four real LNG carrier ships.

[2] Most of the information were gathered from www.marinetraffic.com and www.vesselfinder.com.

Table 4.2: Selected LNG Carrier Model Vessels and their Characteristics

LNG Carrier Name	LNG Storage Cap	Length Overall (LOA)	Breadth	Gross Tonnage	(Summer) DWT	Draught	Average Speed	Maximum Speed	Minimum Depth in Wharf
	CBM	Metre (m)	Metre (m)	Tonne	Tonne	Metre (m)	Knots	Knots	Metre (m)
Engie Zeebrugge	5,000	107.60	18.4	7,403	3,121	4.80	9.66	11.52	5.28
Aman Hakata	18,000	130.00	25.7	16,336	10,951	5.50	9.96	11.57	6.05
JS Ineos Independence	27,500	180.30	26.6	22,887	20,916	8.00	13.23	15.29	8.80
Navigator Nova	35,000	179.89	29.6	27,546	27,014	9.17	13.40	14.57	10.08

CBM = cubic metre, DWT = deadweight tonnage.
Source: Authors' elaboration from data available at www.marinetraffic.com and www.vesselfinder.com.

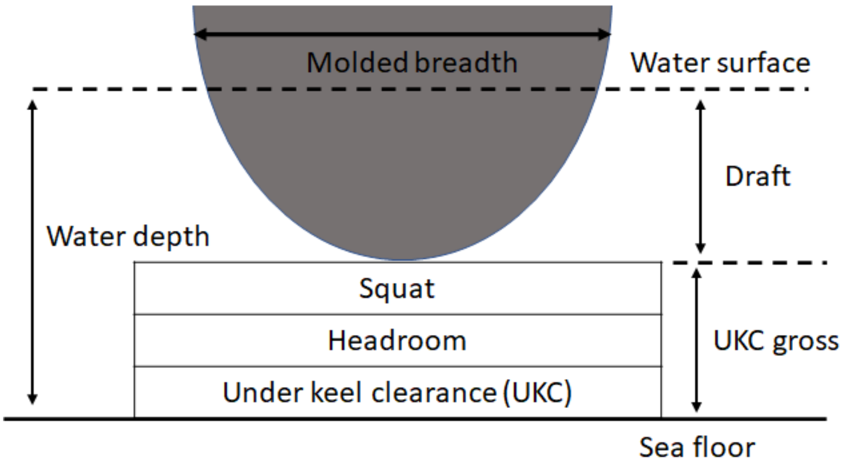
Figure 4.2: Selected Model Vessels

Source: www.marinetraffic.com.

The minimum (water) depth of the wharf in Table 4.2 is the minimum water depth that a seaport needs to have in one of its wharfs so that an LNG carrier vessel can enter the seaport.

Figure 4.*3* shows that the water depth at the wharf comprises the ship's maximum draft and under keel clearance (UKC) gross. The UKC gross is a necessary depth from the bottom of the sea that allows for the ship's squat movement whilst providing for headroom like semi-wave height and heeling and a clearance depth. The minimum UKC gross is set at 10% of the maximum ship's draft. The minimum water depth is then calculated as the maximum ship's draft multiplied by a factor of 1.1.

Figure 4.3: Under Keel Clearance Concept



Source: Authors' elaboration.

3. Proposed LNG Receivers or Seaports

Based on the UKC concept, LNG carrier model vessels' required minimum water depth at the wharf, and the information and data of minimum depth in channel/basin/wharf we received from the Directory General of Seaports of the Ministry of Transportation, we determined the accessibility of each seaport for each LNG vessel. A seaport is accessible by an LNG vessel when the minimum depth of one of its channels, basins, and wharf is bigger than the vessel's required minimum wharf. The results are given in Table 4.3 where we finally selected 20 seaports that should serve as LNG receiving terminals.

Table 4.3: Selected LNG Receiver Seaports and their Accessibility for LNG Carrier Model Vessels

LNG Carrier Vessel Models			**Shinju Maru**	**Engie Zeebrugge**	**Aman Hakata**	**JS Ineos Independence**	**Navigator Nova**
LNG Storage Cap (CBM)			**2,513**	**5,000**	**18,000**	**27,500**	**35,000**
Minimum Depth in Wharf (m)			**4.61**	**5.28**	**6.05**	**8.80**	**10.08**
Port Location	Port Name	Minimum depth-channel/basin/wharf	Port Accessibility				
Center Sulawesi	Palu–Pantoloan	9	1	1	1	1	0
South Sulawesi	Makassar New Port	16	1	1	1	1	1
North Sulawesi	Bitung	12	1	1	1	1	1
Bali	Benoa	9	1	1	1	1	0
Lombok, West Nusa Tenggara	Lembar	7	1	1	1	0	0
Sumbawa, West Nusa Tenggara	Badas	7	1	1	1	0	0
Flores (West side), East Nusa Tenggara	Labuhan Bajo	10	1	1	1	1	0
Kupang, East Nusa Tenggara	Tenau	17	1	1	1	1	1
Buru Island, Maluku	Namlea	8	1	1	1	0	0
Ambon, Maluku	Ambon	25.9	1	1	1	1	1

Ternate, North Maluku	Ternate Kota Baru	12	1	1	1	1	1
Yapen Island (Serui), Papua	Serui	10	1	1	1	1	0
Biak, Papua	Biak	9	1	1	1	1	0
Merauke, Papua	Merauke	7	1	1	1	0	0
Jayapura, Papua	Jayapura	9	1	1	1	1	0
Manokwari, West Papua	Manokwari	12	1	1	1	1	1
Sorong City, West Papua	Sorong	15	1	1	1	1	1

Accessible:	1
Not Accessible:	0

Source: Authors' elaboration.

Chapter 5
Outlook of LNG Production

1. LNG Development in Indonesia

Indonesia has been producing LNG since 1977, starting from the Badak LNG plant and followed by the Arun LNG plant in 1978. During its peak operation, LNG Arun consisted of six trains with a total capacity of 12.85 MTPA. The Bontang LNG plant consisted of eight trains with a total capacity 22.5 MTPA. Two more LNG plants were put on stream afterwards. These were LNG Tangguh, with a capacity of 7.6 MTPA on stream in 2009, and LNG Donggi Senoro, with a capacity 2 MTPA on stream in 2014. However, due to declining gas resources, the production of LNG Arun ceased in 2014. The current total capacity of an LNG plant in Indonesia is 31.4 MTPA. The declining gas reserves in East Kalimantan led to the closure of four trains in the Badak LNG plant. In 2019, the total LNG production of Indonesia was 16.4 MTPA: 6.4 MT from the Badak LNG plant, 7.8 MT from the Tangguh LNG plant, and 2.2 MT from the Donggi Senoro LNG plant.

Although LNG production declined from 19.1 MT in 2015 to 16.4 MT in 2019 due to declining production in LNG Badak, the projected Indonesian LNG production will rebound after train 3 LNG Tangguh is completed in 2022. This will expand the plant capacity by 3.8 MTPA, totalling 11.4 MTPA. The projected Masela LNG plant will add about 9 MTPA in capacity in 2028.

In addition to large-scale LNG plants, Indonesia started developing small-scale LNG plants to monetise stranded small gas fields. Gas technology development, either in transporting or processing technology, provides an opportunity to utilise stranded small gas resources. A national downstream company, PT Kayan LNG Nusantara, will develop a small LNG plant in Tana Tidung, North Kalimantan. The plant will process 22 MMSCFD gas from Simenggaris field operated by PT Pertamina Hulu Energi Simenggaris and PT Medco E&P Simenggaris. . This project will start in December 2021.

Three more companies had secured the licence to build small-scale LNG plants. These are (i) PT Paraamartha LNG which will build an LNG plant in Sidoarjo with a capacity of 170 tonnes/day, (ii) PT Sumber Aneka Gas which will build an LNG plant in Tuban with a feed gas of 15 MMSCFD, and (iii) PT Natgas, which will build an LNG plant in Batam with a capacity of 50 tonnes/ day. LNG production will be mainly generated by the Bontang, Tangguh, Donggi, Masela plants, and several small-scale LNG plants that are expected to be on stream by 2030.

1.1. Badak LNG Plant

The Badak LNG Plant, located in Bontang East Kalimantan, was built to process gas from Muara Badak field operated by Huffco, a Pertamina production-sharing contractor, and sell it as LNG to buyers in Japan. The first train, train A, started its production in July 1977 and shipped the first LNG to Japan in August 1977. The Badak LNG plant expanded to eight trains with a total capacity 22.5 MTPA. For almost 4 decades of the operation, LNG Badak had already shipped more than 59,000 cargoes. However, due to declining gas sources, only four trains of LNG Badak were recently in operation.

According to the Indonesian *Natural Gas Balance* issued by the MEMR (2018), the Badak LNG plant will continue producing LNG until 2030 and beyond. The raw materials are expected to be supplied by Mahakam Gas fields operated by Pertamina Hulu Mahakam and Muara Bakau field operated by ENI. Additional supply is expected from IDD Ganal field operated by Chevron, which will be on stream in 2025 at the rate of 205 MMSCFD and will be increased up to 844 MMSCFD by 2027. However, after reaching its peak production in 2027, gas supply will decline in 2028 from 844 to 769 MMSCFD in 2029, and 709 MMSCFD in 2030.

Natural gas from ENI East Sepinggan (Marakes) is going to be on stream in 2021 at 147 MMSCFD and will reach its peak production at 371 MMSCFD in 2023. The amount of production will naturally decline but it will keep producing gas up to 2029. The outlook of Badak LNG production and allocation is indicated in Figure 5.1.

Figure 5.1: Outlook LNG Badak Production and Allocation

Source: MEMR (2018).

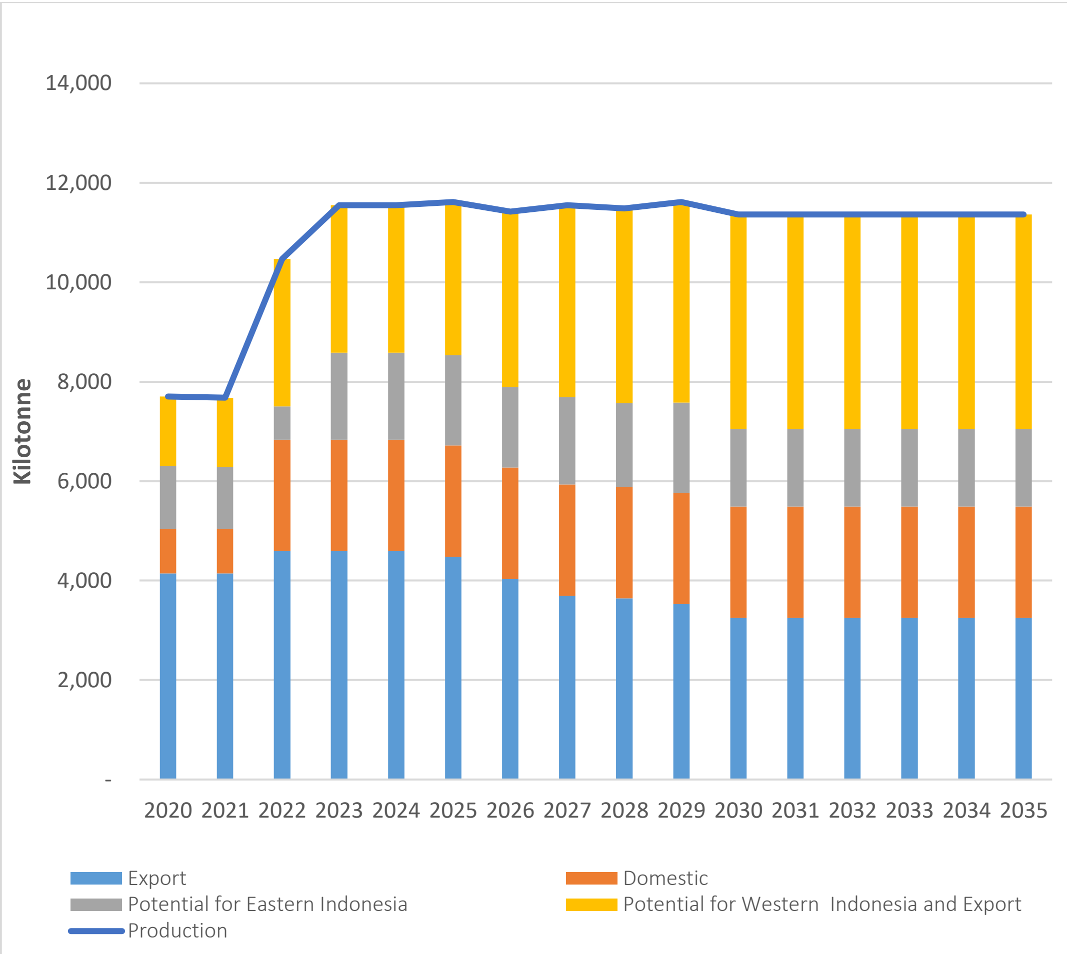
The production of Badak LNG plant in 2020 will reach 6,047 kilotonnes. All production is shipped to domestic and Japanese buyers. However, the slowing down of economic activities due to the Covid-19 pandemic, which started in December 2019, has led to the curtailment of production. Demand is expected to rebound in 2021 as the pandemic could be handled globally and economic activity would go back to normal. Badak LNG production will be limited by the availability of gas. Under the Indonesian *Natural Gas Balance*, Badak LNG production will reach 4,553 kilotons in 2021. As the new gas resources go on stream, production will increase to 7,221 kilotons in 2025 and decline afterwards to 2,424 kilotons in 2030.

Badak LNG production is allocated for both export and domestic markets. Contracted exports at 780–902 kilotons/year will end in 2025. However, contracted sales for domestic buyers at 1,934 kilotons/year have been signed up to 2023. Although the continuation of sales contracts with domestic buyers beyond 2023 and overseas buyers beyond 2025 have not been secured yet, most likely the domestic buyers in Arun, Medan, Lampung, and West Java will need LNG supply from Bontang. In addition, LNG Badak will continuously seek the export market, especially in East Asia, since the LNG market in East Asia offers the best price. Only 792 kilotons and 265 kilotons of LNG from Badak will be available to meet the LNG demand of Eastern Indonesia in 2025 and 2030, respectively.

1.2. Tangguh LNG Plant

The Tangguh LNG plant, located in Bintuni Bay West Papua, was developed by BP Indonesia[3] and its partners to monetise natural gas found around Bintuni Bay such as Berau, Wiriagar, and Muturi. The first two train LNG plants with a total capacity 7.8 MTPA was constructed in 2005 and completed in 2009. The third train with a 3.8 MTPA capacity is still being constructed and expected to be completed at the end of 2021. Figure 5.2 shows the outlook of LNG Tangguh production.

Figure 5.2: Outlook Tangguh LNG Production and Allocation



Source: MEMR (2018) and Authors' analysis.

[3] https://www.bp.com/id_id/indonesia/home/siapa-kami/tangguh-lng.html.

In 2020, LNG Tangguh is expected to produce 130 cargoes of LNG equal to 7,800 kilotons of LNG. Amongst its production, 88 cargoes equivalent to 5,100 kilotons will be exported, 33 cargoes or 2,100 kilotons will be delivered to domestic consumers, and about 9 cargoes are about to go to the spot market. Train 3 of LNG Tangguh will start its production in 2022 and is expected to reach its maximum capacity in 2023. LNG Tangguh will maintain its peak production at 11.4 MTPA from 2023 to 2028, and the production will decline afterwards. However, there are opportunities to find more gas reserves to maintain peak production beyond 2030. From 2020 to 2025, 60% of Tangguh LNG production will be allocated for export, 35% for the domestic market, and the rest of 5% will be distributed to the spot market as it is not covered by the LNG sales agreement with any buyer yet. From 2025 to 2033, the production of LNG Tangguh will be allocated for the domestic and export markets equally, between 3.6 to 3.9 MTPA. There will be growing uncommitted LNG cargoes from LNG Tangguh of 2,000 kilotons in 2025 to 4,100 kilotons in 2028. Those uncommitted cargoes will most likely go to the domestic gas market in Western and Eastern Indonesia or to export. To supply the demand in Eastern Indonesia, the potential volume available in LNG Tangguh will be 1,750 kilotons in 2023; 1,800 kilotons in 2025, and 1,560 kilotons in 2030.

1.3. Donggi Senoro LNG

The Donggi Senoro LNG (DSLNG) Plant is located in Banggai Regency in the Province of Central Sulawesi and is situated about 45 km south-east of Luwuk, the main town of Banggai Regency. DSLNG was a downstream LNG plant, owned by a company established in 2007, with its shares owned by Pertamina Energy Services Pte Ltd (29%), PT Medco LNG Indonesia (20%), and Mitsubishi Corporation (51%). The DSLNG plant processes gas sent by the Senoro Toili Block at the rate of 250 MMSCFD, the Matindok Block at the rate of 85 MMSCFD, and liquefies it at 2 MTPA LNG. As projected, gas resources from these two fields currently supply DSLNG and will be continuously available up to 2030 or 2035. Basically, LNG produced by the DSLNG plant is exported to Japan (1 MTPA for Jera and 0.3 MTPA for Kyusu Electric), and the Republic of Korea (KOGAS 0.7 MTPA). However, DSLNG also sends LNG to the Arun Regasification Unit and FSRU West Java due to declining export demand, or on cargo swap mechanism with Bontang or Tangguh LNG plant.

1.4. Masela LNG

The Masela LNG plant will liquefy gas from the Abadi Field that was found in 2002 and confirmed by appraisal in 2013 and 2014. The Abadi Field Plan of Development was submitted to the government by Inpex and Shell assuming LNG production will be 9 MTPA, consisting of onshore LNG plant and offshore floating production and storage offloading as workplace for wells operation onshore. The plan of development was approved by the government in 2019. The government of Maluku Province issued the permit for plant construction in Nustual Island of the Tanimbar islands. The expected final investment decision will be made in 2020.

Masela LNG is starting to find buyers. A memorandum of understanding with PLN, Indonesia's state electricity company, was signed in February 2020 where PLN expressed its intention to utilise LNG from Masela to fuel the power plant. Certainly, the Masela LNG plant needs more buyers to secure the project. Most likely, the government will allocate the LNG from Masela for fulfil domestic and export demand.

There is strong indication that the future LNG market is from the buyers' market. Many LNG projects in Australia, Africa, and the Middle East will deliver LNG to the market, including the Masela LNG plant, which is expected to be on stream in 2027. The projection of Indonesian LNG supply was made with the assumption that expected or planned projects will be successful in delivering the LNG as planned. However, in case of any disruption, Indonesia could benefit from the international market by importing LNG to supply domestic demand, especially for Eastern Indonesia. As in the Arun LNG facility case, the government will most likely convert the Bontang facility into LNG storages for imported LNG before LNG is distributed to consumers.

2. Conclusion

If upstream gas projects will go as planned, Indonesia could provide LNG to the eastern islands to replace oil consumption in power plants and industries in other regions of the country. Success in finding new gas reserves through intensive exploration will prolong the availability of gas and LNG to secure the energy needed by the country. However, some circumstances such as delay in project execution could lead to LNG deficit. In such a case, Indonesia could rely on the international LNG market. The development of medium- and small-scale receiving terminals is imperative in securing the supply.

Chapter 6
Static Approach for Delivering LNG: Linear Programming

This chapter describes the optimal solutions for delivering LNG from its production sites to its demand sites by applying the linear programming (LP) model.

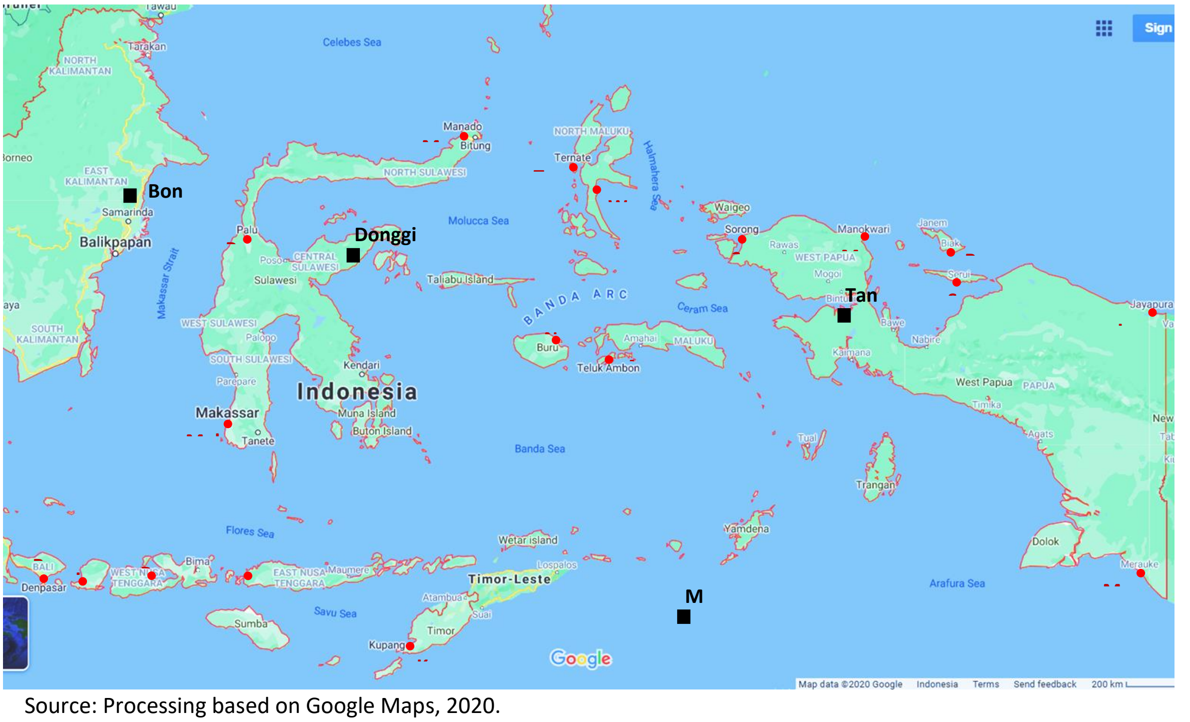
1. Prerequisites for Developing the LP Model

1.1. Assumptions

a. Target area

The target area is Eastern Indonesia (Figure 6.1). The map shows the LNG demand sites, comprising names of cities and ports. Table 6.1 shows the abbreviations of both port names of LNG production and demand sites. Hereinafter, we refer to the abbreviations.

Figure 6.1: Boundary of LNG Delivery Model

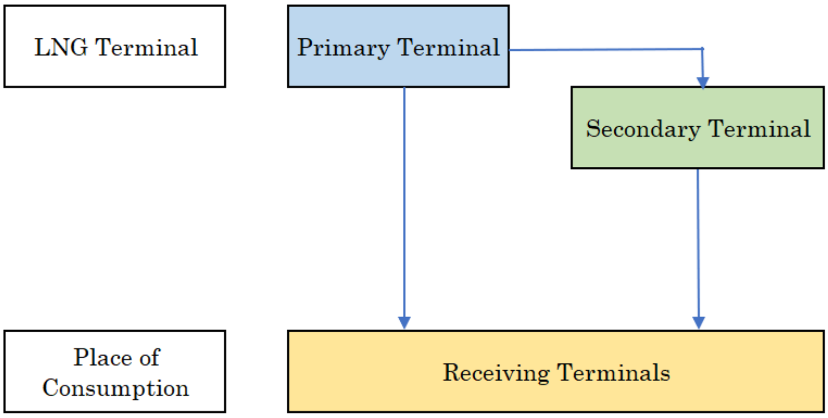


Source: Processing based on Google Maps, 2020.

b. Delivery flow of LNG in this area

LNG for domestic use in this area will be delivered from four LNG production sites – Bontang, Donggi Senoro, Masela, and Tangguh – to LNG demand sites. At the LNG receiving sites, LNG storages and its regasification units will be equipped. This study applies to two delivery routes: (i) primary terminals (LNG production sites) to the receiving terminals directly and (ii) via a secondary terminal (Figure 6.2). Basically, small and midsized LNG tankers will be engaged to deliver LNG in this area.

Figure 6.2: LNG Delivery Flow



Source: Authors.

Table 6.1: LNG Production Sites and Demand Sites

Potential Location	Code No.	City Name	Port Name	Abbreviation
North Sulawesi	0	Manado	Bitung	MND
Center Sulawesi	1	Palu	Pantolan	PAL
South Sulawesi	2	Makassar	Makassar	MKS
Bali	3	Benoa	Benoa	BNO
Lombok, West Nusa Tenggara	4	Lembar	Lembar	LMB
Sumbawa, West Nusa Tenggara	5	Badas	Badas	BDS
Flores, East Nusa Tenggara	6	Labuan Bajo	Labuan Bajo	LBJ
Kupang, East Nusa Tenggara	7	Kupang	Tensu	KPG
Ambon, Maluku	8	Ambon	Ambon	AMB
Buru Island, Maluku	9	Namlea	Namlea	NLA
Halmahera (South), North Maluku	10	Weda	Weda	WED
Ternate, North Maluku	11	Ternate	Ternate	TTE
Yapen Island, Papua	12	Serui	Serui	SRU
Biak, Papua	13	Biak	Biak	BIK
Manokwari, West Papua	14	Manokwari	Manokwari	MNK
Sorong, West Papua	15	Sorong	Sorong	SON
Merauke, Papua	16	Merauke	Merauke	MRK
Jayapura, Papua	17	Jayapura	Jayapura	JAP

LNG Terminal	Abbreviation
Bontang	BON
Donggi Senoro LNG	DSL
Masela	MSL
Tangguh	TGH

Source: Badan Standardisasi Nasional (2010).

c. Future LNG demand at 18 receiving sites

Chapter 4 forecasted LNG demand at 18 sites; the forecasted results are shown in Table 6.2.

Table 6.2: Forecasted LNG Demand at 18 Receiving Sites in 2030

No	Potential Location			2030									Gas	Liquid
				Demand Electricity	Own Use & Losses T&D	Own Use & Losses T&D	Production Electricity	Production from CCGT	Capacity of CCGT	Output	Efficiency CCGT	Input	Gas Consumption (/year)	LNG Consumption (/year)
	Location	City Name	Port Name	GWh	GWh	%	GWh	GWh	GW	ktoe	%	ktoe	million m³	kiloton
0	North Sulawesi	Manado	MND	6,719	993	12.9%	7,712	1,097	0.18	94	39%	242	269	192
1	Center Sulawesi	Palu	PAL	14,892	2,200	12.9%	17,092	1,416	0.23	122	39%	312	346	247
2	South Sulawesi	Makassar	MKS	16,799	2,482	12.9%	19,281	1,313	0.21	113	39%	290	321	230
3	Bali	Benoa	BNO	9,602	1,418	12.9%	11,020	2,968	0.48	255	39%	655	727	519
4	Lombok	Lembar	LMB	3,659	540	12.9%	4,199	2,599	0.42	224	39%	573	636	454
5	Sumbawa	Badas	BDS	1,560	230	12.9%	1,791	1,475	0.24	127	39%	325	361	258
6	Flores	Labuan Bajo	LBJ	868	128	12.9%	996	597	0.10	51	39%	132	146	104
7	Kupang	Kupang	KPG	824	122	12.9%	946	565	0.09	49	39%	125	138	99
8	Ambon	Ambon	AMB	449	66	12.9%	516	516	0.08	44	39%	114	126	90
9	Buru	Namlea	NLA	375	55	12.9%	431	431	0.07	37	39%	95	105	75
10	Halmahera (South)	Weda	WED	7,382	1,090	12.9%	8,472	2,597	0.42	223	39%	573	636	454
11	Ternate	Ternate	TTE	2,458	363	12.9%	2,821	2,541	0.41	218	39%	560	622	444
12	Yapen Island (Serui)	Serui	SRU	116	17	12.9%	134	134	0.02	11	39%	29	33	23
13	Biak	Biak	BIK	177	26	12.9%	203	203	0.03	18	39%	45	50	36

14	Manokwari	Manokwa ri	MNK	857	127	12.9%	983	881	0.14	76	39%	194	216	154
15	Sorong City	Sorong	SON	1,232	182	12.9%	1,414	1,414	0.23	122	39%	312	346	247
16	Merauke	Merauke	MRK	274	40	12.9%	314	293	0.05	25	39%	65	72	51
17	Jayapura City	Jayapura	JAP	360	53	12.9%	413	131	0.02	11	39%	29	32	23

Source: Authors.

d. Distance from LNG production sites to demand sites (nautical miles)

Table 6.3 shows the distances between LNG production sites and demand sites, based on the existing data and author’s estimations.

Table 6.3: Distance between LNG Production and Demand Sites

Miles (NM)

Production base	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	MND	PAL	MKS	BNO	LMB	BDS	LBJ	KPG	AMB	NLA	WED	TTE	SRU	BIK	MNK	SON	MRK	JAP
BON	402	144	345	578	556	532	543	941	1,092	971	890	753	1,436	1,318	1,248	1,126	2,030	1,761
DSL	363	723	564	796	774	667	564	665	568	515	572	314	900	869	766	622	1,330	1,165
MSL	765	980	695	873	868	767	621	420	350	389	558	623	906	876	772	456	678	1,201
TGH	649	1,030	945	1,165	1,143	1,042	901	777	428	467	441	558	725	694	591	383	760	992

Source: Authors.

e. Distance between LNG demand sites (nautical miles)

To apply the milk-run method, distances between LNG demand sites were also prepared as Table 6.4.

Table 6.4: Distance between LNG Demand Sites

Nautical miles (NM)

No.	Port	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
		MND	PAL	MKS	BNO	LMB	BDS	LBJ	KPG	AMB	NLA	WED	TTE	SRU	BIK	MNK	SON	MRK	JAP
0	MND		493	714	1,051	973	843	765	791	402	376	480	221	843	791	649	532	1,142	1,116
1	PAL	493		323	572	551	511	505	903	844	932	848	714	1,397	1,279	1,209	1,087	1,991	1,723
2	MKS	714	323	572	324	311	298	207	441	587	597	739	779	1,673	1,647	1,544	1,375	2,011	1,985
3	BNO	1,051	572	324		59	161	351	542	837	1,178	947	987	2,005	1,414	1,817	1,105	1,626	2,331
4	LMB	973	551	311	59		146	293	513	804	1,122	895	1,399	1,949	1,381	1,761	1,072	1,570	2,275
5	BDS	843	511	298	161	146		161	439	675	688	921	934	1,271	1,219	1,155	973	1,531	1,245
6	LBJ	765	505	207	351	293	161		308	545	558	791	804	1,142	1,090	1,025	843	1,401	1,116
7	KPG	791	903	441	542	513	439	308		485	575	763	852	1,402	1,091	1,214	1,076	1,023	1,728
8	AMB	402	844	587	837	804	675	545	485		98	280	322	820	655	632	285	713	971
9	NLA	376	932	597	1,178	1,122	688	558	575	98		224	322	584	532	467	285	843	856
10	WED	480	848	739	947	895	921	791	763	280	224		210	519	493	389	221	856	830
11	TTE	221	714	779	987	1,399	934	804	852	322	322	210		584	558	454	285	908	895
12	SRU	843	1,397	1,673	2,005	1,949	1,271	1,142	1,402	820	584	519	584		114	188	392	1,168	349

13	**BIK**	791	1,279	1,647	1,414	1,381	1,219	1,090	1,091	655	532	493	558	114		127	321	1,142	314
14	**MNK**	649	1,209	1,544	1,817	1,761	1,155	1,025	1,214	632	467	389	454	188	127		236	1,090	427
15	**SON**	532	1,087	1,375	1,105	1,072	973	843	1,076	285	285	221	285	392	321	236		921	637
16	**MRK**	1,142	1,991	2,011	1,626	1,570	1,531	1,401	1,023	713	843	856	908	1,168	1,142	1,090	921		1,577
17	**JAP**	1,116	1,723	1,985	2,331	2,275	1,245	1,116	1,728	971	856	830	895	349	314	427	637	1,577	

Source: Authors.

f. Annual LNG delivery amounts for domestic uses at four sites (2030)

The maximum LNG delivery amounts for domestic use in 2030 per each LNG production site are forecasted in Chapter 5 (see Table 6.5 for the summary).

Table 6.5: Annual LNG Delivery Amounts for Domestic Use at Each LNG Production Site, 2030

LNG Terminal	Gas Million CBM	LNG Kiloton
Bontang	576	265
Donggi Senoro LNG	1,087	500
Masela	10,327	4,750
Tanggu	3,391	1,560
Total	**15,380**	**7,074**

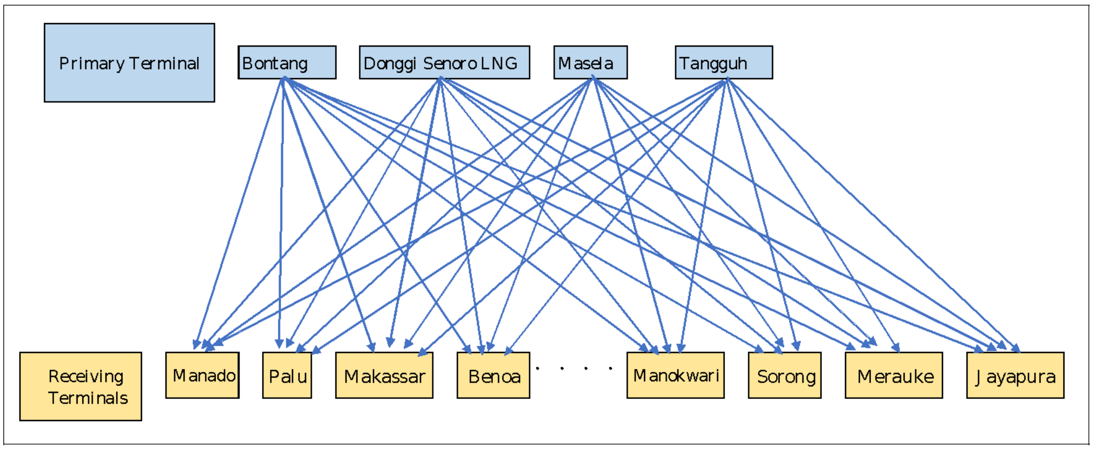
Source: Authors.

The LNG production amount of Bontang and Donggi is significant so far but LNG delivery amounts for domestic use at Bontang and Donggi are not assumed significantly because these LNG production sites cater to the export market. Therefore, the role of Masela and Tangguh to deliver LNG to LNG demand sites in this area is crucial.

2. Formulas and Solutions of the LP Model

Figure 6.3 shows the formulation of the LP model for delivering LNG. Basically, the LP model applies a hub-and-spoke method, meaning, delivering LNG from the origin (LNG production sites) to the destination (LNG demand sites) directly. The LP model seeks for an optimal solution to minimise costs, represented as the summation of LNG delivery amount (i to j) x distance (i to j), where i means origin and j means destination.

Figure 6.3: LNG Delivery in the Linear Programming Model



Source: Authors.

The formulas of Figure 6.3 are shown below. There are only two constraints: LNG production and LNG demand. These formulas are referred to as case 1.

$$\Sigma Xij = annual\ LNG\ production\ amount\ at\ production\ site\ i\ (Aj)\quad j$$

$$\Sigma Xij = annual\ LNG\ consumption\ amount\ at\ demand\ site\ j\ (Bj)\quad i$$

$$\Sigma\Sigma Dij * Xij \rightarrow Minimum\quad i\quad j$$

Where,

Xij = Delivering LNG amount from production site I to demand site j (tonne)

Dij = Distance between production site I to demand site j (nautical mile)

2.1. Case 1 (No constraints case)

a. Input data

Supply constraints Ai is shown in Table 6.5 and demand constrains Bj in Table 6.2. The upper limit Uij is assumed basically as same number of Bj.

Table 6.6: Input Data of the Linear Programming Model

Production base	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Supply
	MND	PAL	MKS	BNO	LMB	BDS	LBJ	KPG	AMB	NLA	WED	TTE	SRU	BIK	MNK	SON	MRK	JAP	
BON	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	265
DSL	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	500
MSL	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	4,750
TGH	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	1,560
Demand	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	7,074
																		Total	**3,701**

Source: Authors.

b. LP solution (case 1)

Table 6.7 shows the solution of case 1 from the LP model and the following key findings:

- Bontang LNG production site will deliver LNG to Palu and Makassar of Sulawesi. On the other hand, Donggi Senoro will deliver its LNG to Manado and Ternate of north Maluku and Makassar.
- Masela will deliver its LNG to Makassar of South Sulawesi, Benoa, Lembar, Badas, Labuan Bajo, Kupang, Ambon, Namlea of Nusa Tenggara islands, and Merauke of South Papua.
- Tangguh will deliver its LNG to five cities in North Papua and Weda of North Maluku.
- Manado will receive LNG from Donggi Senoro and Palu supplied from Bontang.
- Only Makassar will receive LNG from three LNG production sites: Bontang, Donggi Senoro, and Masela.

Table 6.7: Linear Programming Solution of Case 1

Production base	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Supply	Supply
	MND	PAL	MKS	BNO	LMB	BDS	LBJ	KPG	AMB	NLA	WED	TTE	SRU	BIK	MNK	SON	MRK	JAP	Solution	input
BON	0	247	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	265	265
DSL	192	0	56	0	0	0	0	0	0	0	0	444	0	0	0	0	0	0	500	500
MSL	0	0	157	519	454	258	104	99	90	75	0	0	0	0	0	0	51	0	1,808	4,750
TGH	0	0	0	0	0	0	0	0	0	0	454	0	23	36	154	247	0	23	937	1,560
Demand	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	2,088,367	7,074
check	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	3,701	

Source: Authors.

2.2. Case 2 to represent similar real operation of LNG delivery

a. Input *data*

Since the solution from the LP model (case 1) did not show the real operation of LNG delivery, appropriate constraints were added to case 1 to represent similar real operation. The constraints brought the following merits:

- Improved efficiency of LNG transport through the allocation of a group of neighbouring cities to an LNG production site
- Fixed LNG supply amounts by each LNG production base
- Provided overall framework of a dynamic simulation model

As a result, the following constraints were added (refer to Table 6.8):

- Bontang will deliver its LNG only to Central Sulawesi (Palu).
- Donggi will cover Manado and South Sulawesi (Makassar).
- Masela will deliver LNG to Bali, Lombok, Sumbawa, Flores, Kupang, Ambon, Buru, and Ternate (eight demand sites).
- Tangguh will deliver its LNG to Halmahera, Yapen Island, Biak, Monokwari, Sorong, Merauke, and Jayapura city (seven demand sites)

b. LP solution

Case 2 results (Table 6.9) suggest that the value of the objective function is 2,213,109 (tonne/km) and it increases by 6% from case 1. Consequently, the constraints do not affect the objective function seriously and case 2 is still the second option of case 1 to represent a more realistic LNG delivery. Case 2 also suggests LNG delivery in the following three groups: (i) Bontang–Donggi group, (ii) Masela group, and (iii) Tangguh group (Table 6.9).

Table 6.8: Constraints to LNG Delivery (Upper Limit: Uij), kiloton

Production Base	0 MND	1 PAL	2 MKS	3 BNO	4 LMB	5 BDS	6 LBJ	7 KPG	8 AMB	9 NLA	10 WED	11 TTE	12 SRU	13 BIK	14 MNK	15 SON	16 MRK	17 JAP	Supply
BON	192	247	0	0	0	0	0	99	90	75	454	444	23	36	154	247	51	23	265
DSL	192	247	230	0	0	0	0	99	90	75	454	0	23	36	154	247	51	23	500
MSL	192	247	0	519	454	258	104	99	90	75	454	444	23	36	154	247	0	23	4,750
TGH	192	247	230	519	454	258	104	99	90	75	454	0	23	36	154	247	51	23	1,560
Demand	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	7,074
																	Total	**3,701**	

Source: Authors.

Table 6.9: **Linear Programming Solution**

Production Base	0 MND	1 PAL	2 MKS	3 BNO	4 LMB	5 BDS	6 LBJ	7 KPG	8 AMB	9 NLA	10 WED	11 TTE	12 SRU	13 BIK	14 MNK	15 SON	16 MRK	17 JAP	Supply Solution	Supply input
BON	0	247	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	247	265
DSL	192	0	230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	421	500
MSL	0	0	0	519	454	258	104	99	90	75	0	444	0	0	0	0	0	0	2,044	4,750
TGH	0	0	0	0	0	0	0	0	0	0	454	0	23	36	154	247	51	23	988	1,560
Demand	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	2,213,109	7,074
Check	192	247	230	519	454	258	104	99	90	75	454	444	23	36	154	247	51	23	3,701	

Note:

Bontang–Donggi Senoro group :

Masela group :

Tangguh group :

Source: Authors.

Chapter 7

Dynamic Approach for Delivering LNG: Dynamic Simulation

1. Data Required for Simulation

1.1. Basic concept of the simulation model

The dynamic simulation (DS) model to simulate LNG delivery from LNG production sites to demand sites was developed using the simulator 'WITNESS'. The model features are:

- It simulates LNG delivery by the tankers dynamically.
- It pages an LNG tanker when the LNG stock reaches a certain LNG amount in the storage tank.
- The minimum time unit for the simulation is 'minute'.
- The simulation period is 1 year (365 days).

The major simulation parameters are as follows:

- LNG tanker (type, storage capacity, speed, origin, and destination port)
- LNG onshore storage (capacity, initial LNG storage level, criteria for calling tanker)
- Water depth of each LNG receiving port
- Route (distance) is the same as the LP model
- Location of LNG shipping terminal (origin)
- Location of LNG receiving terminal (destination)
- Delivery route from origin to destination
- Capacity of LNG tanker (weight: tonne)
- Time for loading/unloading, etc.

1.2. LNG onshore storage capacity and LNG tanker size

a. LNG onshore storage capacity

- Initial LNG stock shall need more than 10 days of gas consumption for power generation.
- The maximum storage capacity (days) shall be 1.5 times the number of days needed for LNG delivery (round trip)
- The four kinds of storage and a secondary port storage are assumed for the DS and the characteristics are summarised in Table 7.1.

Table 7.1: Characteristics of LNG Onshore Storage

Size	MTPA	Storage (CBM)	Weight (kiloton)	CAPEX (million US$)	OPEX (million US$ per year)
SS	～0.06	5,000	2.30	75	1.88
S	0.7～0.2	20,000	9.20	121	3.02
M	0.21～0.4	30,000	13.80	139	3.49
L	0.41～	50,000	23.00	177	4.43
Second port storage		150,000	69.00	366	9.15

Note: OPEX = CAPEX * 2.5%.
Source: Authors.

b. LNG tanker size

Four kinds of LNG tanker and the tanker to transport LNG from the primary port to the secondary port (second port tanker) and their characteristics are listed in Table 7.2.

Table 7.2: Characteristics of LNG Tanker

Type	Gross Tonnage (ton)	LNG Storage Capacity (CBM)	LNG Storage Weight (kiloton)	Water Depth (m)	Average Speed (kilo knot)	Calculated CAPEX (Million US$)	OPEX (Million US$/year)
SS	7,403	5,000	2.3	5.28	9.7	36.9	2.4
S	16,336	18,000	8.3	6.05	10.0	48.7	4.2
M	22,887	27,500	12.7	8.8	13.2	52.5	4.8
L	27,546	35,000	16.1	10.08	13.4	54.8	5.1
Second port tanker	83,846	70,000	32.2	12.00	13.4	81.1	9.3

Note: OPEX is calculated by daily cost x 300 days; OPEX's calculation excludes fuel cost.
Source: Authors.

1.3. Other necessary data

a. Water depth per port

The water depth of each LNG receiving site (port) is shown in Table 7.3. The table also indicates the available LNG tanker size, such as L size, at the Manado LNG receiving port.

Table 7.3: Water Depth at Each LNG Receiving Port

Unit: metre

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Water Depth	MND	PAL	MKS	BNO	LMB	BDS	LBJ	KPG	AMB	NLA	WED	TTE	SRU	BIK	MNK	SON	MRK	JAP
	12	12	9	9	7	7	10	17	26	8	-	12	10	9	12	15	7	9
Tanker Type	L	L	M	L	S	S	L	L	L	S	S	L	M	M	L	L	S	M

Source: Authors.

b. Time of loading and unloading of LNG

Unloading time: 12 hours, Loading time: 12 hours.

2. LNG Delivery Simulation by Each Group

For LNG delivery, the following three cases are simulated per each group (Bontang–Donggi, Masela, and Tangguh).

Case 1: Apply the hub & spoke method

Assign an LNG tanker to each route from an LNG origin as a hub to all LNG destinations.

Case 2: Apply sharing LNG tanker method

Apply the hub & spoke method but assign an LNG tanker to many routes from an LNG origin to plural LNG destinations.

Case 3: Apply the milk-run method

This method delivers LNG to several destinations from an LNG origin per navigation. The destinations should be close each other.

2.1. Bontang–Donggi group

Figure 7.1 shows the image of LNG deliveries in the Bontang–Donggi group. Bontang ships LNG to Palu and Donggi ships LNG to Manado and Makassar.

Figure 7.1: Image of the Simulation on PC screen (Bontang–Donggi Group)

Source: Authors.

Conditions of LNG shipping and receiving ports, LNG onshore storages, and LNG tankers

Water depth, annual LNG consumption, LNG onshore storage capacity, and type of LNG tanker to be initially assigned are summarised in Table 7.4. The number of LNG tankers and their sizes are shown in Table 7.5.

Table 7.4: Input Conditions for Simulation

Production Base	No.	Port abbreviation	Port Water Depth	Annual Consumption (kiloton)	Onshore Storage			Tanker Sstorage			
					Type	Capacity (CBM)	Weight (kiloton)	Water Depth (m)	Type	Capacity (CBM)	Weight (kiloton)
BON	1	PAL	9	247	M	30,000	13.80	6.05	S	18,000	8.28
DSL	0	MND	12	192	M	30,000	13.80	6.05	S	18,000	8.28
	2	MND	12	230	M	30,000	13.80	6.05	S	18,000	8.28

CBM = cubic metre, m = metre.
Source: Authors.

Table 7.5: Number and Size of Tankers (Cases 1–3)

	BON-DSL		
	1.PAL	0.MND	2.MKS
Case 1	S	S	S
Case 2	S	S	
Case 3	M		

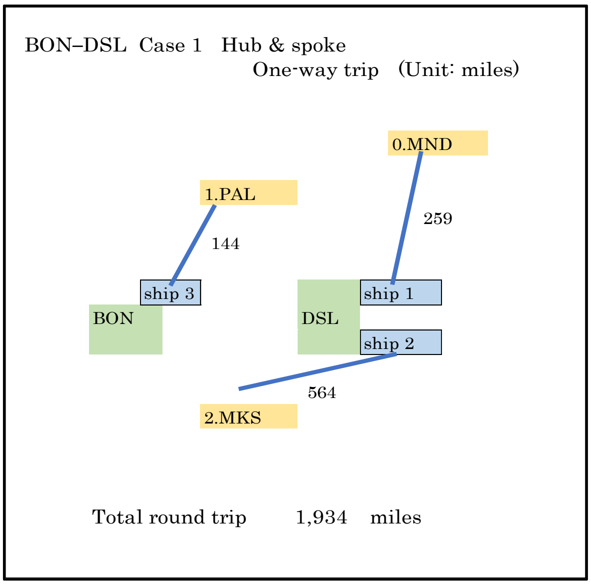
Source: Authors.

a. Case 1: Hub & spoke method

1) Image of tanker operation

Figure 2.7 shows a conceptual picture of LNG delivery from Bontang to Palu and Donggi–Senoro to Manado and Makassar.

Figure 7.2: LNG Delivery from Terminal, BON–DSL, Hub & Spoke Method (Case 1)



Source: Authors.

2) Operational status of storage

The simulation results of case 1 show several useful information of LNG onshore storages at three LNG receiving ports (Table 7.6) such as:

- No shortage has happened at the three receiving ports.
- In terms of the storage capacity at the three ports, 30,000 CBM is appropriate per the simulation results of three indicators, which are maximum, minimum, and average levels of storage.

Figure 7.3 also shows the storage level of the three LNG receiving ports. It indicates that the capacity of the storage will be oversized if contingency is ignored. Table 7.6 shows that the contingency level will be 15%. Theoretically, we can reduce the capacity of the storages to around 22,000 CBM but in case of emergencies, such as accidents and natural disasters, black out will occur due to LNG shortage. Thus, 30,000 CBM will be appropriate including contingency.

Table 7.6: Operational Status of LNG Onshore Storage, BON–DSL (Case 1)

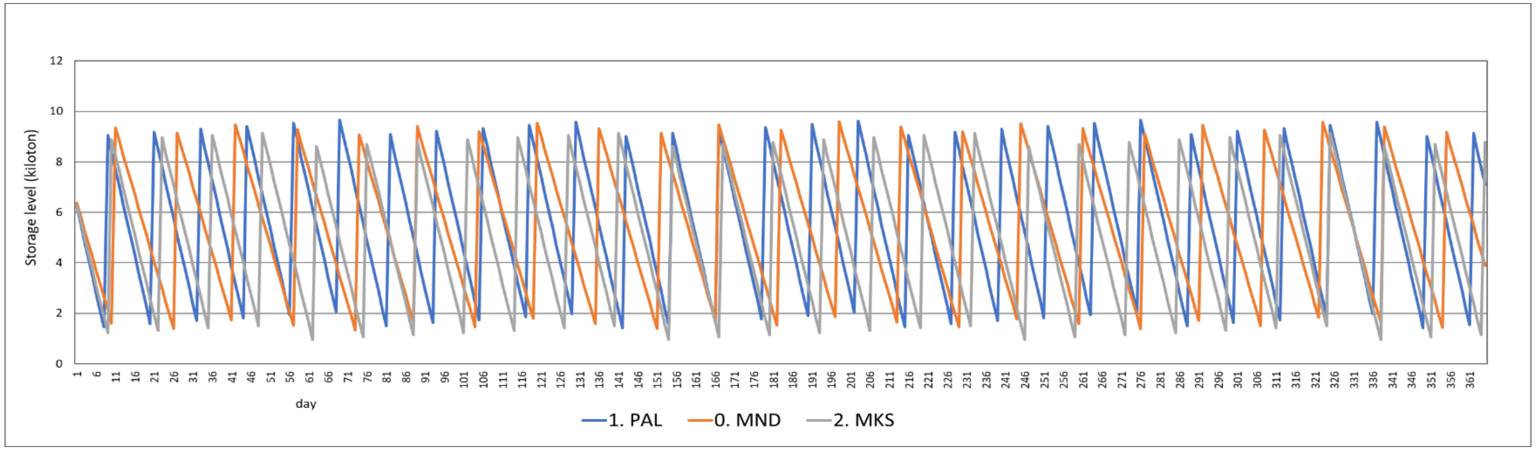
Operational Status of Storage	1.PAL	0.MND	2.MKS	Total
Storage size	M	M	M	
Storage capacity (CBM)	30,000	30,000	30,000	
Storage capacity (kiloton)	13.8	13.8	13.8	41.4
①Initial value of storage (kilotons)	6.9	6.9	6.9	20.7
②Unloading weight (kiloton/year)	248.4	190.4	231.8	670.7
Tanker unloading volumes (kiloton/time)	8.28	8.28	8.28	
Level of calling a tanker (kiloton)	3.45	3.45	3.45	
Number of unloading (times)	30	23	28	
Maximum level of storage (kiloton)	11.73	11.73	11.73	
Minimum level of storage (kiloton)	1.42	1.33	0.96	
Average level of storage (kiloton)	9.66	9.6	9.15	
Maximum level/Storage capacity	0.85	0.85	0.85	
③Stock at end of period (kiloton)	7.1	3.89	8.79	19.8
④Total supply (kiloton) ①＋②－③	248.2	193.5	230.0	671.6
⑤Annual consumption （kiloton）	247.5	191.8	229.6	668.9
⑥Comparison ④/⑤	1.00	1.01	1.00	1.00

Source: Authors.

3) Operational status of LNG tankers

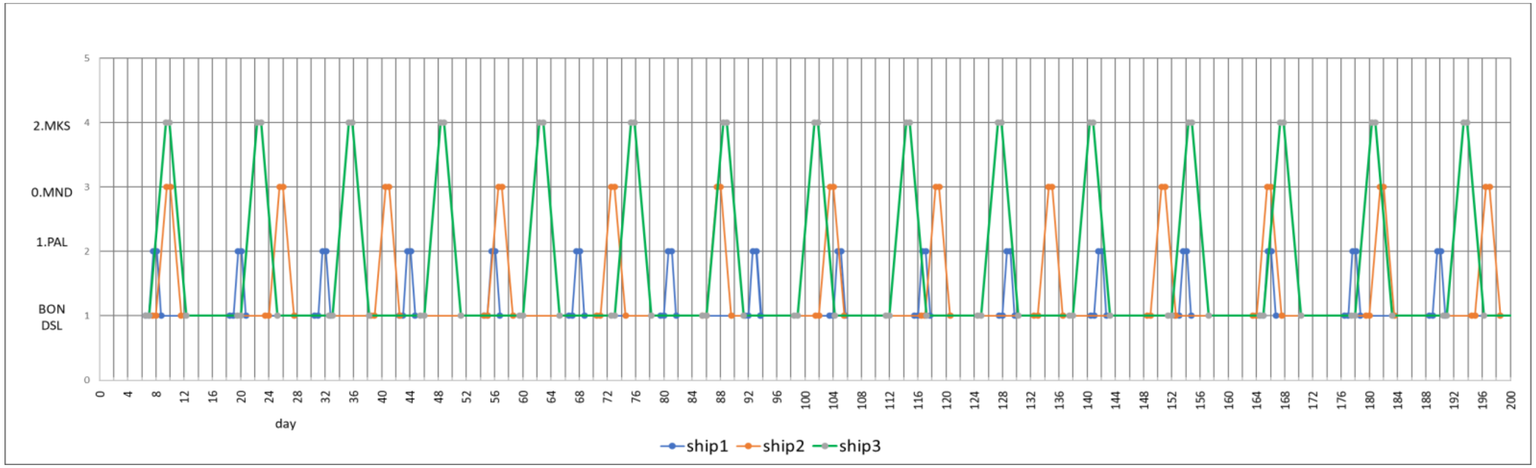
Figure 7.4 shows the operation of LNG tankers. This diagram covers the simulation results for 100 days of three tankers engaged to deliver LNG to three LNG demand sites. Due to different LNG consumption amounts in each destination, the number of LNG delivery to Makassar is seven times, six times for Manado, and eight times for Palu.

Figure 7.3: Storage Level of Each Port, BON–DSL (Case 1)



Source: Authors' analysis.

Figure 7.4: Diagram of Tanker Operations, BON–DSL (Case 1)



Source: Authors' analysis.

4) Key findings

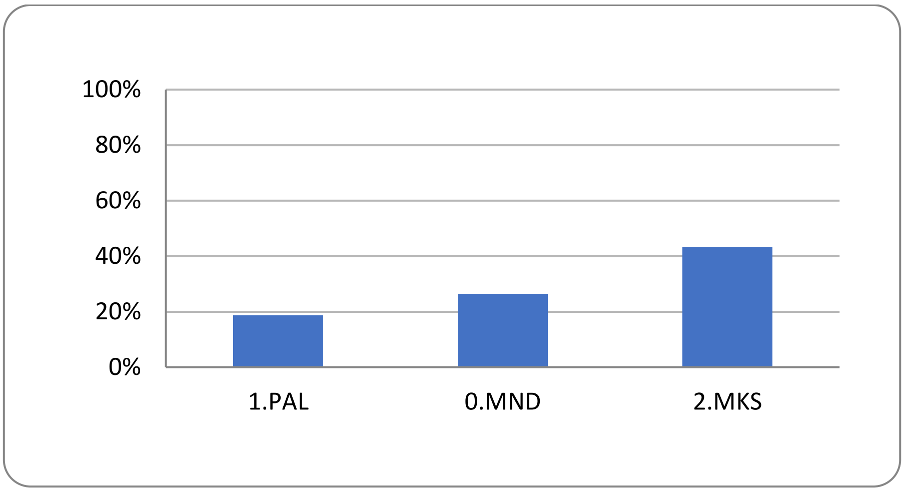
Table 7.7 shows the operational status of an LNG tanker per each route. The table also includes total annual data of waiting time (idling time), loading time, transporting time, unloading time, operating time, total time, operating rate, and the number of loading and unloading times. The operating rate of each tanker is quite low (19%–43%) especially the LNG tanker navigating between Bontang and Palu. This result shows the possibility of reducing the number of ships.

Table 7.7: Operational Status of LNG Tankers, BON–DSL, Hub & Spoke (Case 1)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
BON	1.PAL	1	7,068	360	894	360	1,614	8,682	19%	30	30
DSL	0.MND	2	6,287	276	1,695	276	2,247	8,534	26%	23	23
	2.MKS	3	4,951	336	3,077	336	3,749	8,700	43%	28	28
Total			**18,306**	**972**	**5,666**	**972**	**7,610**	**25,916**	**29%**	**81**	**81**

Source: Authors.

Figure 7.5: Operation Rate of Each LNG Tanker, BON–DSL (Case 1)



Source: Authors.

In addition, the operation cost of an LNG tanker per each route is estimated based on cruising distances, unloading volumes, and assumed unit of OPEX, which is fixed operating expense referring to Japanese statistics. The operation cost of a route between Donggi and Makassar is highest due to longer distance and remarkable unloading amount of LNG.

Table 7.8: Operation Cost of LNG Tankers, BON–DSL, Hub & Spoke (Case 1)

						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (round-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/ year)**
BON	1.PAL	S	8,640	248	35,770	5.9	0.21
DSL	0.MND	S	11,914	190	49,324	5.9	0.29
	2.MKS	S	31,584	232	130,758	5.9	0.77
Total			**52,138**	**671**	**215,851**		**1.27**

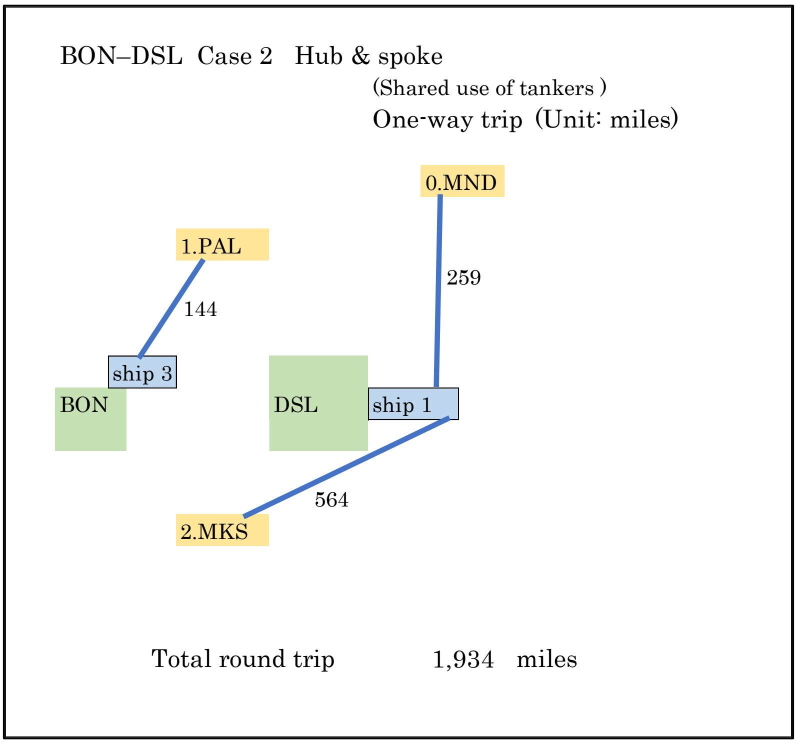
Source: Authors.

b. **Case 2: Sharing LNG tanker method**

1) **Operation of two LNG tankers**

Table 7.5 shows the number and size of LNG tankers. Case 2 assumes one tanker operation from Donggi to Manado and Makassar. The image is shown in Figure 7.6.

Figure 7.6: LNG Delivery from LNG Terminals, BON–DSL, Hub & Spoke Method (Case 2)



Source: Authors.

2) **Operational status of LNG storages**

The simulation results of case 2 are shown in Table 7.9. Table 7.9 and Figure 7.7 suggest the following:

- The maximum storage level at Manado and Makassar increases to 13.03 kilotons and 12.62 kilotons, respectively, from case 1 and they are close to their capacities (13.8). But the storage capacity of 30,000 CBM is still feasible.
- The initial volume of LNG onshore storages at Manado and Makassar must increase from 6.9 kilotons to 9.2 kilotons to avoid fuel shortage resulting from a longer delivery time of LNG than case 1.
- The storage level to page an LNG tanker increases from 3.45 kilotons to 6.9 kilotons due to longer delivery time of LNG.
- The minimum storage level at Makassar is lower than Palu, 2.0 kilotons and 2.82 kilotons, respectively, depending on the distance from the LNG origin. Donggi and Makassar are 564 miles apart, much farther than Donggi and Manado at 259 miles. (Figure 7.6).

Table 7.9: Operational Status of Onshore Storage, BON–DSL (Case 2)

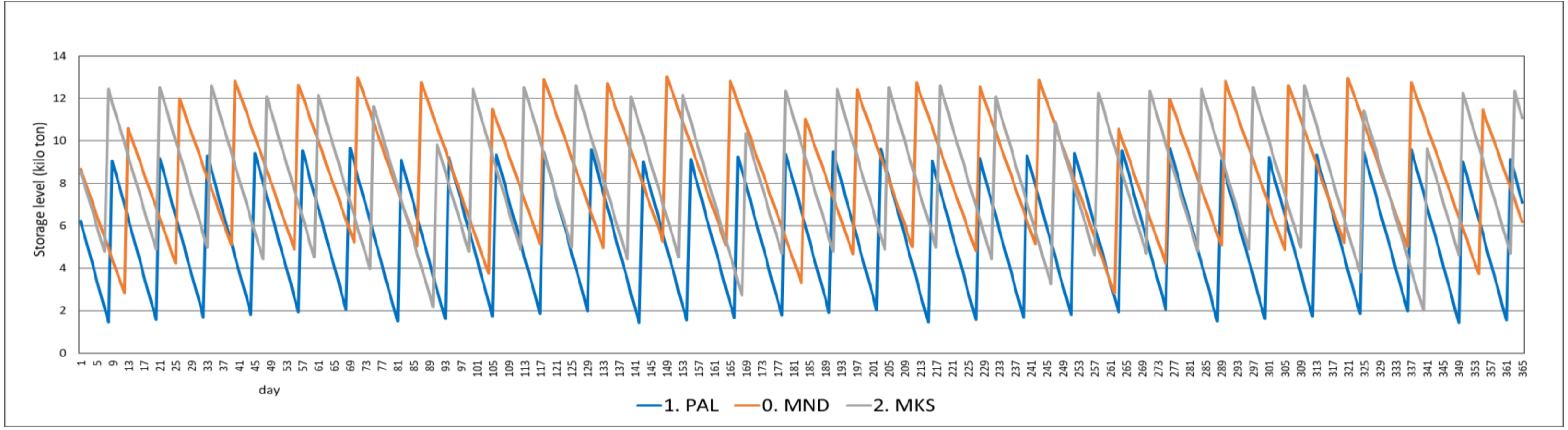
Operational status of storage	1.PAL	0.MND	2.MKS	Total
Storage size	M	M	M	
Storage capacity (m^3)	30,000	30,000	30,000	
Storage capacity (kiloton)	13.8	13.8	13.8	41.4
①Initial value of storage (kilo tons)	6.9	9.2	9.2	25.3
②Unloading weight (kiloton/year)	248.4	190.4	231.8	670.7
Tanker unloading volumes (kiloton/time)	8.28	8.28	8.28	
Level of calling a tanker (kiloton)	3.45	6.9	6.9	
Number of unloading (times)	30	23	28	
Maximum level of storage (kiloton)	9.66	13.03	12.62	
Minimum level of storage (kiloton)	1.42	2.82	2.0	
Average level of storage (kiloton)	5.5	8.4	8.2	
Maximum level / Storage capacity	0.70	0.94	0.91	
③Stock at end of period (kiloton)	7.1	6.19	11.09	24.4
④Total supply (kiloton) ①＋②－③	248.2	193.5	230.0	671.6
⑤Annual consumption （kilo ton）	247.5	191.8	229.6	668.9
⑥Comparison ④/⑤	1.00	1.01	1.00	1.00

Source: Authors.

3) Operational status of tankers

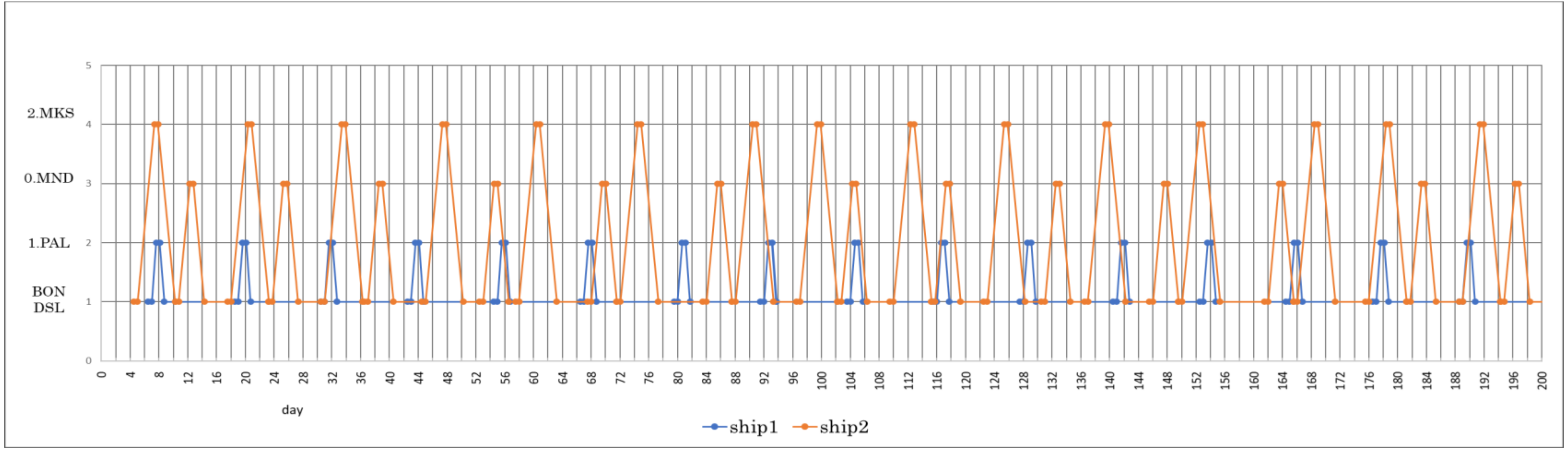
Figure 7.8 shows the operation of two LNG tankers: one between Bontang–Palu and other, between Donggi–Senoro and Manado and Makassar. The orange line is a diagram to monitor the LNG delivery of an LNG tanker (ship 2) to Manado and Makassar from Donggi–Senoro. The number of deliveries to Makassar in the first 100 days is eight times and its increase 1 time from 7 times of Case 1. Since one LNG tanker covers two ports – Manado and Makassar – which consume LNG at a different pace, the delivery timing to Makassar may be faster than case 1. But in case of a whole year, the number of deliveries to Makassar is 28 and it is the same as case 1.

Figure 7.7: Storage Level of Each Port, BON–DSL (Case 2)



Source: Authors' analysis.

Figure 7.8: Diagram of Tanker Operation, BON–DSL (Case 2)



Source: Authors' analysis.

4) Key findings

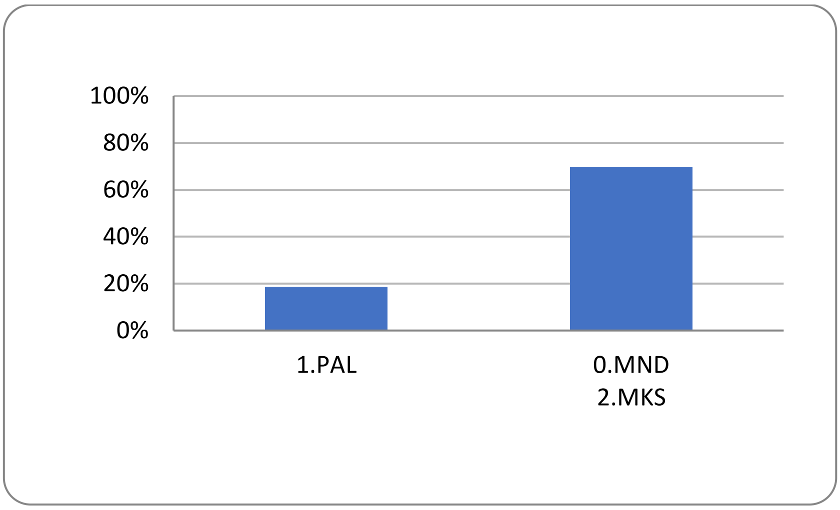
The operation rate of an LNG tanker to deliver LNG to the Manado and Makassar route has risen up to 70% due to the reduced number of ships from two to one.

Table 7.10: Results of Tanker Operations, BON–DSL (Case 2)

Home port terminal	Destination	Tanker number	Waiting time for shipment (hour)	Loading time (hour)	Transport time (hour)	Unloading time (hour)	Operating time (hour)	Total time (hour)	Rate of operation	Number of loading (times)	Number of unloading (times)
BON	1.PAL	1	7,068	360	894	360	1,614	8,682	19%	30	30
DSL	0.MND 2.MKS	2	2,660	612	4,883	612	6,107	8,767	70%	51	51
Total			**9,727**	**972**	**5,777**	**972**	**7,721**	**17,449**	**44%**	**81**	**81**

Source: Authors.

Figure 7.9: Rate of Operation of LNG Tankers, BON–DSL (Case 2)



Source: Authors.

Thus, the operation costs of the LNG tanker at Donggi highly increase to US$1.06 million. Since the distance and unloading amount are the same as case 1, the total operation cost is also the same as case 1. But case 2 can surely reduce the number of LNG tankers to one and the CAPEX of the tanker will not be needed.

The operation cost of the LNG tanker at Donggi is the same as case 1 (US$1.06 million) because the cruising distance and unloading amount are the same as case 1. But case 2 can surely reduce the number of LNG tankers from two to one, so that the CAPEX of the tanker will largely go down.

Table 7.11: Cruising Distance and OPEX of Tankers, BON–DSL (Case 2)

						Tanker OPEX	
Home port terminal	Destination	Tanker Size	Cruise distance (round-trip miles)	Unloading weight (kiloton)	Ton miles (1,000 tonne miles)	Unit price (US$/1,000 tonne miles)	Ship operating costs (Million US$/ year)
BON	1.PAL	S	8,640	248	35,770	5.9	0.21
DSL	0.MND 2.MKS	S	43,498	422	180,082	5.9	1.06
Total			**52,138**	**671**	**215,851**		**1.27**

Source: Authors.

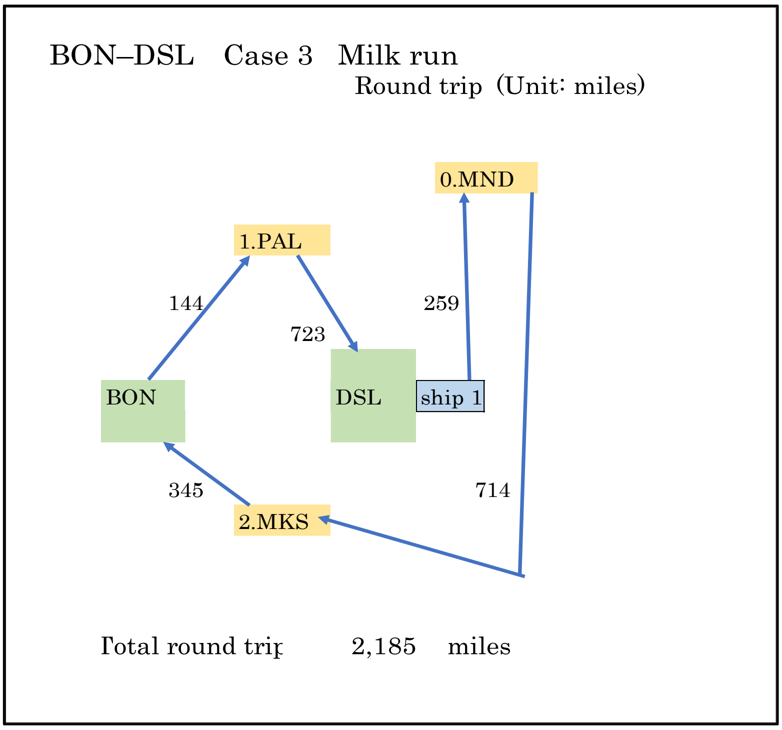
c. Case 3: Milk-run method

Case 3 applies the milk-run method; one LNG tanker moves from two LNG origins to three LNG destinations.

1) Image of an LNG tanker operation

The milk-run method operates an LNG tanker from Donggi Senoro–Manado–Makassar–Bontang–Palu–Donggi Senoro (Figure 7.10). The cruising distance of case 1 is 1,934 miles. On the other hand, the distance of case 3 is 2,185 miles (refer to Table 7.12). But the merit of the milk-run method is that it reduces the number of LNG tankers from two to one.

Figure 7.10: LNG Delivery, BON–DSL, Milk-Run Method (Case 3)



Source: Authors.

Table 7.12: Comparison of Hub & Spoke and Milk-Run Distance

BON-DSL Group	City Name	H&S Round-trip
DSL	0.MND	518
DSL	2.MKS	1128
BON	1.PAL	288
	Total	**1,934**

Don–Bon Group		Milk-Run Round-trip
DSL	DSL—MND	259
	DSL—MND	714
	MKS—BON	345
BON	BON—PAL	144
	PAL—DSL	723
	Total	**2,185**

Source: Authors.

2) Operational status of LNG storage

The simulation results of the LNG onshore storage of each port are shown in Table 7.13. One LNG tanker operation using the milk-run method is still feasible because there is no shortage of LNG as a power generation fuel. Table 7.13 suggests the following:

- The initial volume of the storages must increase from 6.9 kilotons to 9.2 kilotons and it is 4/3 times of case 1.
- The number of unloading times is also the same amongst the three ports because one LNG tanker uses the milk-run method.
- The minimum level of storage at Manado is too high (5.32 kilotons) compared to other ports (1.04 and 2.69 kilotons, respectively). The reason is the application of the milk-run method. The LNG tanker arrives in Manado first and then in Makassar and Palu.

Figure 7.11 shows the stock level of LNG storage at the three ports. The diagram suggests the following:

- The capacity of LNG onshore storage at Manado can be reduced around half of the assumption of LNG onshore storage. In addition, the capacity at other ports, Palu and Makassar, can be cut by around 20%–30% of the assumption.

Table 7.13: Operational Status of LNG Onshore Storage, BON–DSL (Case 3)

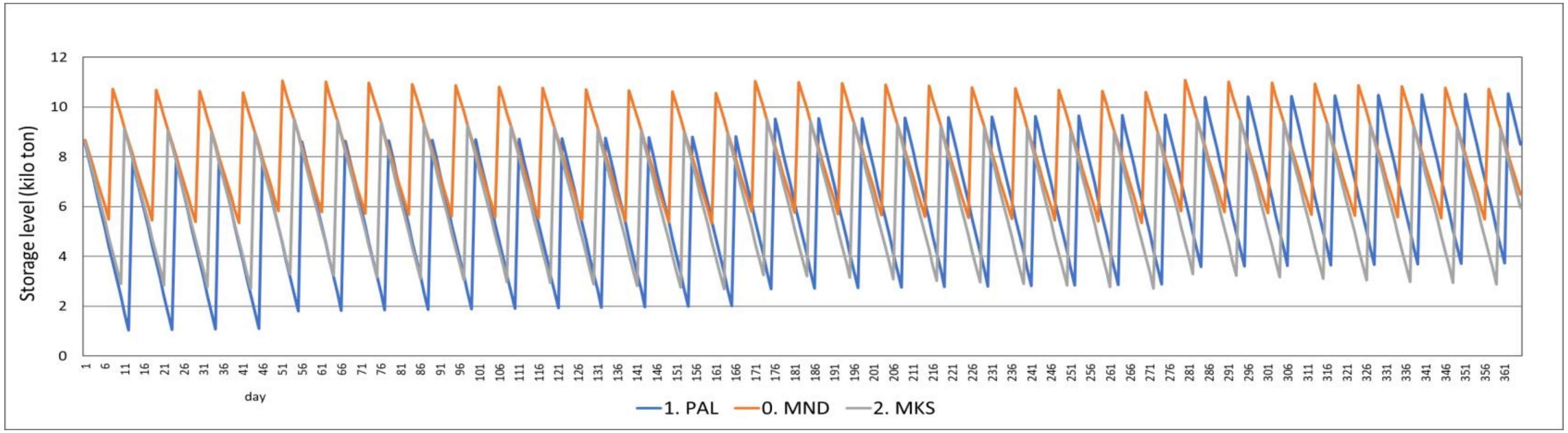
Operational Status of Storage	1.PAL	0.MND	2.MKS	Total
Storage size	M	M	M	
Storage capacity (CBM)	30,000	30,000	30,000	
Storage capacity (kiloton)	13.8	13.8	13.8	41.4
①Initial value of storage (kilotons)	9.2	9.2	9.2	27.6
②Unloading weight (kiloton/year)	248.4	184.7	231.8	664.9
Tanker unloading volumes (kiloton/time)	8.28	8.28	8.28	
Level of calling a tanker (kiloton)	6.9	6.9	6.9	
Number of unloading (times)	33	33	33	99
Maximum level of storage (kiloton)	10.54	11.08	9.53	
Minimum level of storage (kiloton)	1.04	5.32	2.69	
Average level of storage (kiloton)	5.9	8.2	6.1	
Maximum level/Storage capacity	0.76	0.80	0.69	
③Stock at end of period (kiloton)	8.5	6.49	5.96	21.0
④Total supply (kiloton) ①＋②－③	249.1	187.4	235.1	671.6
⑤Annual consumption （kiloton）	247.5	191.8	229.6	668.9
⑥Comparison ④/⑤	1.01	0.98	1.02	1.00

Source: Authors.

3) Operating status of tanker

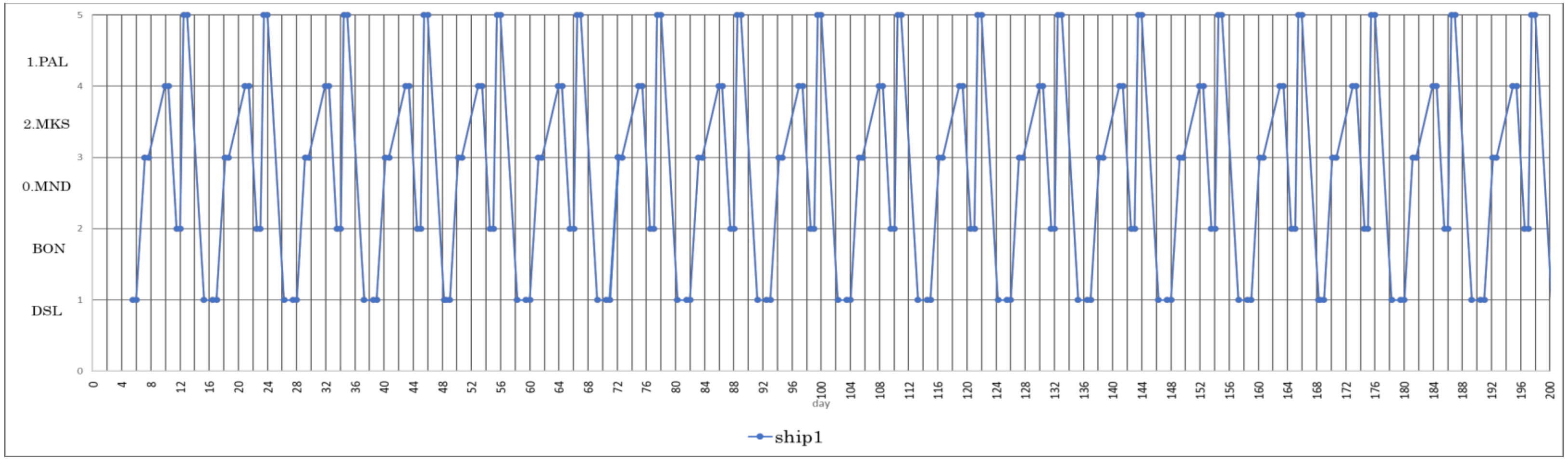
Figure 7.12 is a diagram of case 3. It shows one LNG tanker picking up LNG at two LNG origins (Donggi and Bontang) and transporting it to three LNG destinations (Manado, Makassar, and Palu), ensuring that no LNG shortage happens in 365 days. Table 7.14 shows that the operation rate of the LNG tanker is 88% and its idling time is 12%. Case 3 is a feasible solution, and only one tanker is enough to deliver LNG from the origins to the destinations. One concern is how to assess 12% as contingency. Expert views are needed to assess the contingency rate.

Figure 7.11: Storage Level of Onshore Storage. BON–DSL (Case 3)



Source: Authors' analysis.

Figure 7.12: Diagram of Tanker Operations, BON–DSL (Case 3)



Source: Authors' analysis.

4) Key findings

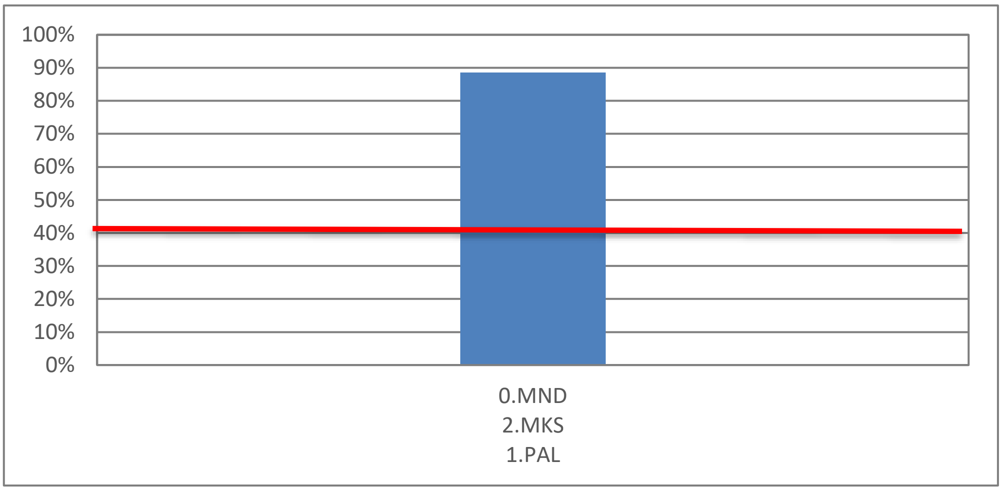
The operating rate of the LNG tanker to cover the three destinations rises to around 90%. Case 3 is an economically feasible solution if around 10% as contingency rate would be acceptable (Table 7.14).

Table 7.14: Results of Tanker Operations, BON–DSL, Milk-Run Method (Case 3)

Home port terminal	Destination	Tanker number	Waiting time for shipment (hour)	Loading time (hour)	Transport time (hour)	Unloading time (hour)	Operating time (hour)	Total time (hour)	Rate of operation	Number of loading (times)	Number of unloading (times)
DSL BON	0.MND 2.MKS 1.PAL	1	1,007	792	5,750	1,188	7,730	8,737	88%	66	99

Source: Authors.

Figure 7.13: Rate of Tanker Operations, BON–DSL (Case 3)



Source: Authors.

The operation cost of case 3 is much higher than cases 1 and 2 due to longer cruising distance, defined as 72,105 – 52,138 = 19,967 miles. Distances between Makassar–Bontang and Palu–Donggi are newly added. Distance between Manado–Makassar is much farther than Donggi–Makassar. However, case 3 uses only one medium-sized LNG tanker in this group.

Table 7.15: Tanker Cruising Distance and OPEX, BON–DSL, Milk-Run Method (Case 3)

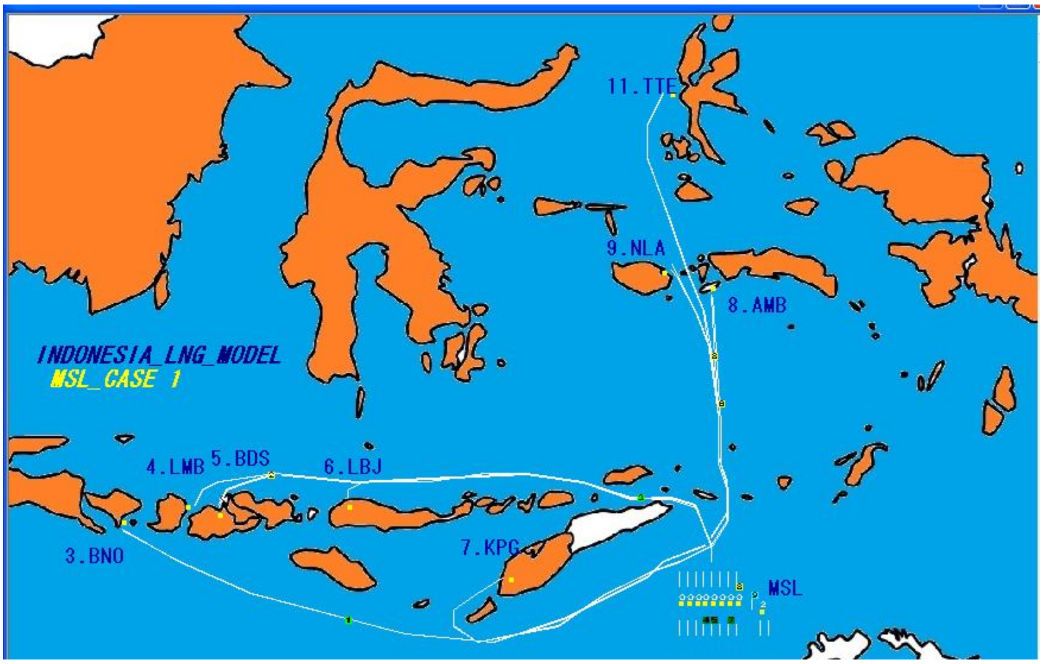
						Tanker OPEX	
Home port terminal	Destination	Tanker Size	Cruise distance (round-trip miles)	Unloading weight (kiloton)	Ton miles (1,000 tonne miles)	Unit price (US$/1,000 tonne miles)	Ship operating costs (Million US$/ year)
DSL BON	0.MND 2.MKS 1.PAL	M	72,105	665	305,630	5.9	1.80

Source: Authors.

2.2. Masela Group

The Masela group consists of one LNG origin (Masela LNG) and eight LNG destinations such as Bali, Lombok, and Ambon. The distances from Masela to the eight LNG destinations are much farther than the Bontang–Donggi group (Figure 7.14).

Figure 7.14: Image of the Simulation on PC Screen (Masela Group)



Source: Authors.

Conditions of LNG shipping and receiving ports, LNG onshore storages, and LNG tankers

Table 7.16 shows the water depth, annual LNG consumption, capacity of LNG onshore storage of each LNG receiving terminal, and size of LNG tanker to be initially assigned to each delivery route.

Table 7.16: Input Conditions for Simulation

Production base	No.	Port abbreviation	Port water depth	Annual consumption (kiloton)	Onshore storage			Tanker storage			
					Type	Capacity (m^3)	Weight (kiloton)	Water depth (m)	Type	Capacity (m^3)	Weight (kiloton)
MSL	3	BNO	9	519	L	50,000	23.00	10.08	L	35,000	16.10
	4	LMB	7	454	L	50,000	23.00	8.8	M	27,500	12.65
	5	BDS	7	258	M	30,000	13.80	6.05	S	18,000	8.28
	6	LBJ	10	104	S	20,000	9.20	6.05	S	18,000	8.28
	7	KPG	17	99	S	20,000	9.20	6.05	S	18,000	8.28
	8	AMB	26	90	S	20,000	9.20	5.28	SS	5,000	2.30
	9	NLA	8	75	S	20,000	9.20	5.28	SS	5,000	2.30
	11	TTE	12	444	L	50,000	23.00	8.8	M	27,500	12.65

Source: Authors.

Number and size of LNG tankers

Case 1 assumes that eight LNG tankers are assigned to eight LNG delivery routes; therefore, eight LNG tankers are needed. Case 2 applies an LNG tanker sharing method where one LNG tanker covers two destinations: Masela–Labuan Bajo/Kupang and Masela–Ambon/Namlea. Case 3 is more ambitious as one LNG tanker covers three destinations applying the milk-run method: one is Masela–Badas/Labuan Bajo/Kupang and other is Masela–Ambon/Namlea/Ternate. Table 7.17 summarises the number and size of LNG tankers in each case.

Table 7.17: Number and Size of Tankers in Each Case

	MSL							
	3.BNO	**4.LMB**	**5.BDS**	**6.LBJ**	**7.KPG**	**8.AMB**	**9.NLA**	**11.TTE**
Case 1	L	M	S	S	S	SS	SS	M
Case 2	L	M	S	S		SS		M
Case 3	L	M	M			M		

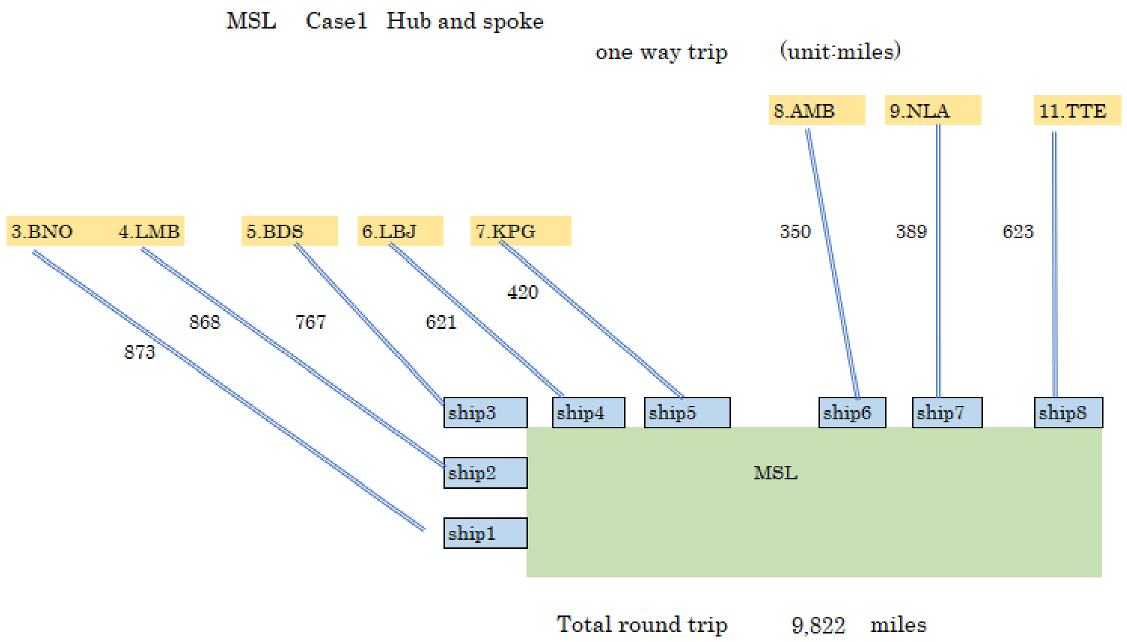
Source: Authors.

a. Case 1: hub & spoke method

2) Image of LNG tanker operation

Case 1 allocates eight LNG tankers to deliver LNG to eight destinations from Masela. Figure 7.15 shows the LNG delivery of case 1 from Masela.

Figure 7.15: LNG Delivery, MSL, Hub & Spoke Method (Case 1)



Source: Authors.

3) Operational status of storage

Table 7.17 shows the simulation results of LNG onshore storage at eight receiving ports. This table indicates the following:

- The initial volume of each LNG onshore storage is assumed to be half of its capacity, but no shortage has happened at the eight receiving ports.
- The LNG storage capacity at Labuan Bajo and Kupang, which is 20,000 CBM, is appropriate due to the simulation results of three indicators: maximum, minimum, and average level of LNG storage.
- On the other hand, the LNG storage capacity of Ambon and Namlea, which is also 20,000 CBM, is oversized because it is less than 50% of the ratio defined as the maximum storage level per storage capacity due to the small LNG demand.

Figure 7.16 shows the LNG storage level of the eight LNG receiving ports. Based on Figure 7.16 and Table 7.18, the LNG storage capacity of Ambon and Namlea can be reduced largely. However, the LNG storage capacity of Benoa, Lembar, Badas, and Ternate seems to be a bit oversized.

4) Operational status of tankers

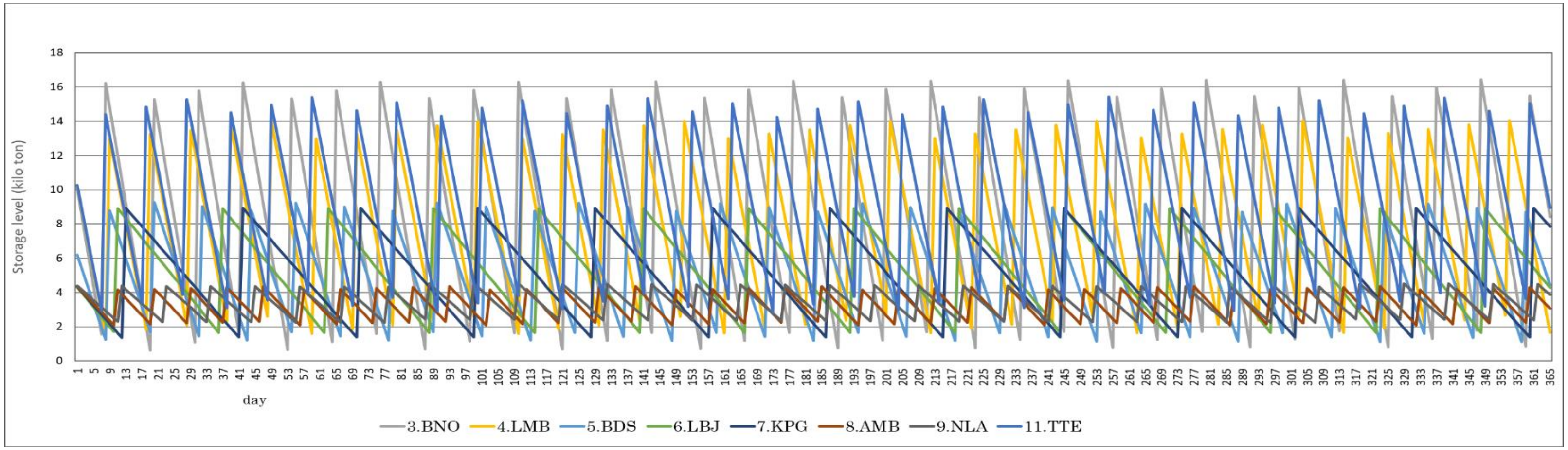
Figure 7.17 clearly shows that the operation of eight LNG tankers in case 1 is feasible. Several LNG tankers also show remarkable idling time due to many LNG tankers. Table 7.19 and Figure 7.18 show the operation status of an LNG tanker per each route. The operation rate of LNG tankers on the four routes of Labuan Bajo, Kupang, Ambon, and Namlea is less than 50%. This result suggests that the number of LNG tankers can be reduced.

Table 7.18: Operational Status of Onshore Storage, MSL (Case 1)

Operational Status of Storage	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	8.AMB	9.NLA	11.TTE	Total
Storage size	L	L	M	S	S	S	S	L	
Storage capacity (CBM)	50,000	50,000	30,000	20,000	20,000	20,000	20,000	50,000	
Storage capacity (kiloton)	23.0	23.0	13.8	9.2	9.2	9.2	9.2	23.0	119.6
①Initial value of storage (kilotons)	11.5	11.5	6.9	4.6	4.6	4.6	4.6	11.5	59.8
②Unloading weight (kiloton/year)	515.2	442.8	256.7	105.5	101.8	89.7	75.9	442.8	2030.3
Tanker unloading volumes (kiloton/time)	16.1	12.7	8.3	8.3	8.3	2.3	2.3	12.7	
Level of calling a tanker (kiloton)	7.67	7.67	4.60	3.07	2.30	3.07	3.07	7.67	
Number of unloading (times)	32	35	31	14	13	39	33	35	232
Maximum level of storage (kiloton)	16.44	14.05	9.26	8.91	8.93	4.35	4.52	15.43	
Minimum level of storage (kiloton)	0.62	1.58	1.12	1.66	1.36	2.1	2.23	2.84	
Average level of storage (kiloton)	8.5	7.8	5.2	5.3	5.1	3.2	3.4	9.1	
Maximum level/Storage capacity	0.71	0.61	0.67	0.97	0.97	0.47	0.49	0.67	
③Stock at end of period (kiloton)	8.4	1.65	6.73	4.85	3.26	4.58	5.38	8.95	43.8
④Total supply (kiloton) ①+②−③	518.3	452.6	256.9	105.3	103.1	89.7	75.1	445.3	2,046.3
⑤Annual consumption (kiloton)	518.9	454.4	257.9	104.4	98.8	90.1	75.3	444.2	2,044.1
⑥Comparison ④/⑤	1.00	1.00	1.00	1.01	1.04	1.00	1.00	1.00	1.00

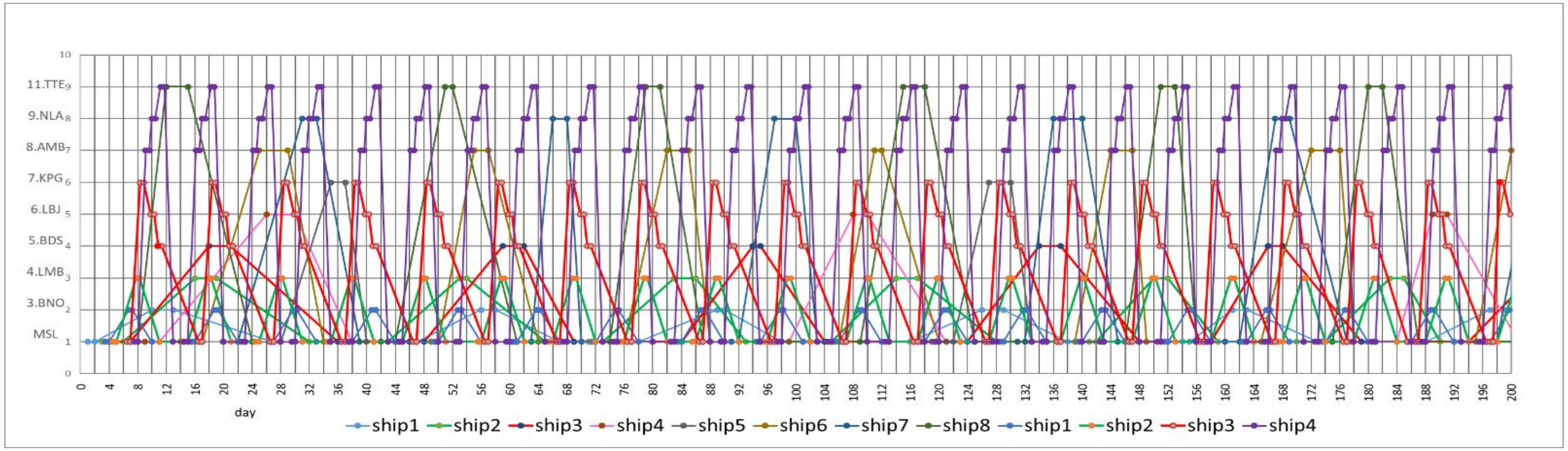
Source: Authors.

Figure 7.16: Storage Level of Onshore Storage, MSL (Case 1)



Source: Authors' analysis.

Figure 7.17: Diagram of Tanker Operations, MSL (Case 1)



Source: Authors' analysis.

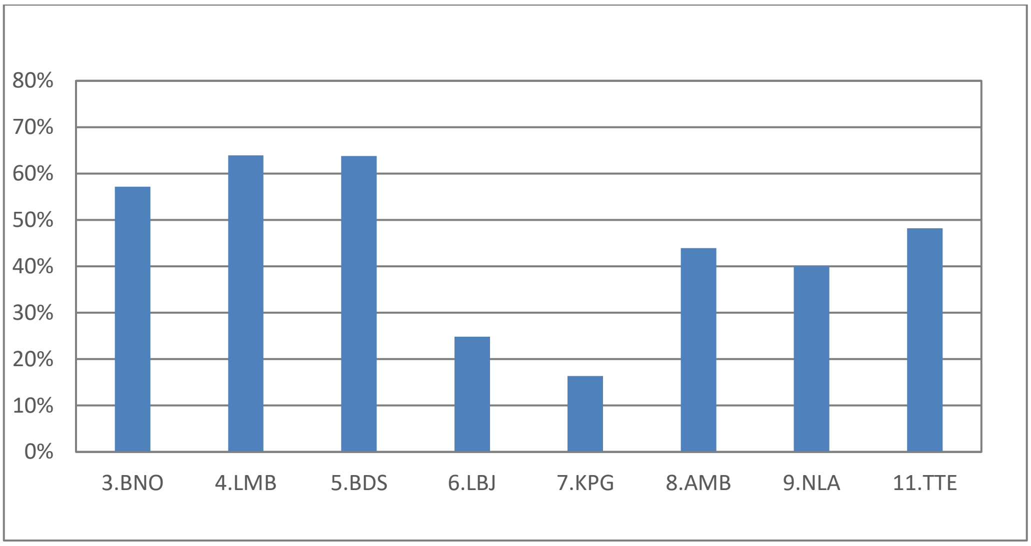
5) Amount of statistics

Table 7.19: Results of Tanker Operations, MSL, Hub & Spoke Method (Case 1)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
MSL	3.BNO	1	3,719	384	4,201	384	4,969	8,687	57%	32	32
	4.LMB	2	3,091	420	4,638	420	5,478	8,569	64%	35	35
	5.BDS	3	3,147	372	4,795	372	5,539	8,686	64%	31	31
	6.LBJ	4	6,325	168	1,756	168	2,092	8,417	25%	14	14
	7.KPG	5	7,270	156	1,107	156	1,419	8,689	16%	13	13
	8.AMB	6	4,852	468	2,866	468	3,802	8,654	44%	39	39
	9.NLA	7	5,220	396	2,698	396	3,490	8,709	40%	33	33
	11.TTE	8	4,493	420	3,343	420	4,183	8,675	48%	35	35
Total			**38,116**	**2,784**	**25,403**	**2,784**	**30,971**	**69,087**		**232**	**232**

Source: Authors.

Figure 7.18: Rate of Tanker Operations, MSL (Case 1)



Source: Authors.

In addition, the operating cost of an LNG tanker per each route is estimated based on cruising distances, unloading volumes, and assumed unit of OPEX. The operation costs of two routes, which are Benoa (Bali) and Lembar (Lombok), are highest based on the long distance from Masala and the high LNG demand due to popular tourist places. On the other hand, the operation costs of Labuan Bajo, Kupang, Ambon, and Namlea are too low due to the shorter distance and smaller LNG demand.

Table 7.20: Cruising Distance and OPEX of Tanker, MSL, Hub & Spoke (Case 1)

						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (round-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/year)**
MSL	3.BNO	L	55,872	515	449,770	5.9	2.65
	4.LMB	M	60,760	443	384,307	5.9	2.27
	5.BDS	S	47,554	257	196,874	5.9	1.16
	6.LBJ	S	17,388	106	65,528	5.9	0.39
	7.KPG	S	10,920	102	42,756	5.9	0.25
	8.AMB	SS	27,300	90	31,395	5.9	0.19
	9.NLA	SS	25,674	76	29,525	5.9	0.17
	11.TTE	M	43,610	443	275,833	5.9	1.63
Total			**289,078**	**2,030**	**1,475,988**		**8.71**

Source: Authors.

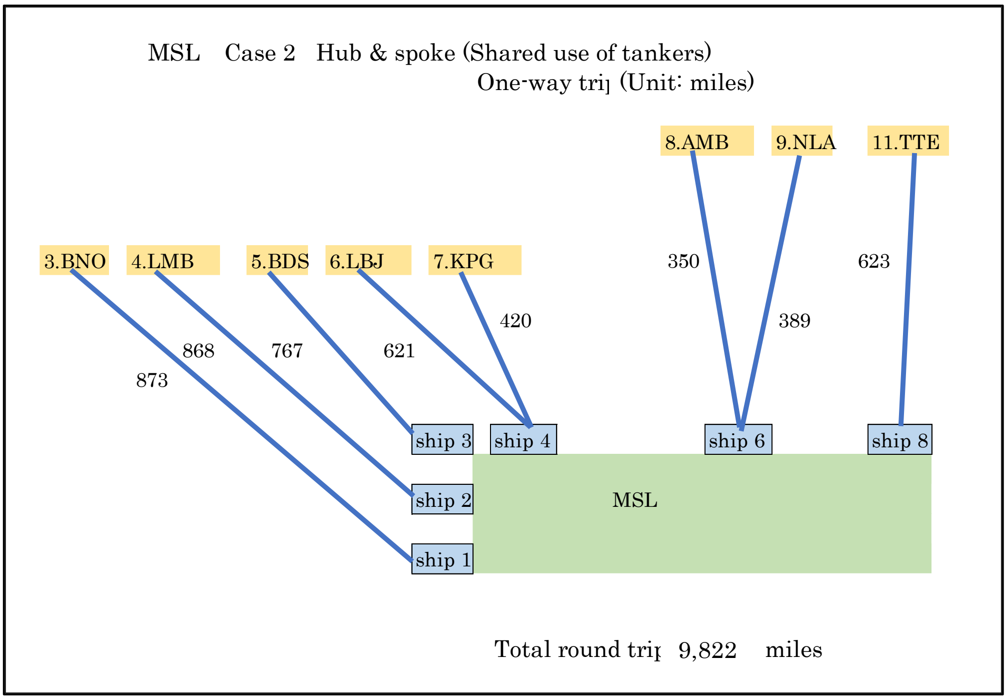
b. Case 2: LNG tanker sharing method (partly executed)

Table 7.17 shows the number and size of LNG tankers in case 2. Per Table 7.19 of case 1, the operation rate of LNG tankers assigned to Labuan Bajo and Kupang, which are adjacent to each other, is less than 30%. The operating rate of LNG tankers at Ambon and Namlea, which are also close to each other, is less than 50%. Therefore, case 2 was conducted to assess the possibility of reducing the LNG tankers from two to one to cover the four destinations: Labuan Bajo, Kupang, Ambon, and Namlea.

1) Image of tanker operation

Case 2 allocates six LNG tankers to deliver LNG from Masala to eight destination ports (Figure 7.19).

Figure 7.19: Delivery from LNG Terminal, MSL, Hub & Spoke Method (Case 2)



Source: Authors.

2) Operational status of storage

Table 7.21 and Figure 7.20 show the simulation results of LNG onshore storages at each port. The table and figure suggest the following:

- Due to the application of the hub & spoke method to one LNG tanker to Labuan Bajo & Kupang and Ambon & Namlea, the initial volume of four LNG onshore storages at Labuan Bajo & Kupang and Ambon & Namlea is on two thirds of its capacity. However, no shortage has happened at the four receiving ports.
- The LNG storage capacity at the four ports where the hub & spoke method was applied to one LNG tanker is appropriate due to the simulation results of three indicators, which are maximum, minimum, and average levels of storage.

Table 7.21: Operational Status of Onshore Storage, MSL (Case 2)

Operational Status of storage	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	8.AMB	9.NLA	11.TTE	Total
Storage size	L	L	M	S	S	S	S	L	
Storage capacity (CBM)	50,000	50,000	30,000	20,000	20,000	20,000	20,000	50,000	
Storage capacity (kiloton)	23.0	23.0	13.8	9.2	9.2	9.2	9.2	23.0	119.6
①Initial value of storage (kilotons)	11.5	11.5	9.2	6.1	4.6	6.1	6.1	11.5	66.7
②Unloading weight (kiloton/year)	515.2	442.8	253.7	105.5	101.8	89.7	75.9	442.8	2027.3
Tanker unloading volumes (kiloton/time)	16.1	12.7	8.3	8.3	8.3	2.3	2.3	12.7	
Level of calling a tanker (kiloton)	7.67	7.67	6.90	4.60	2.30	4.60	4.60	7.67	
Number of unloading (times)	32	35	32	14	13	39	33	35	233
Maximum level of storage (kiloton)	16.44	14.05	11.55	8.91	8.93	5.88	6.05	15.43	
Minimum level of storage (kiloton)	0.62	1.58	1.78	1.78	1.36	2.88	2.99	2.84	
Average level of storage (kiloton)	8.5	7.8	6.7	5.6	5.1	4.6	4.7	9.1	
Maximum level/Storage capacity	0.71	0.61	0.84	0.97	0.97	0.64	0.66	0.67	
③Stock at end of period (kiloton)	8.4	1.65	6.73	4.85	3.26	4.58	5.38	8.95	43.8
④Total supply (kiloton) ①＋②－③	518.3	452.6	256.2	106.8	103.1	91.3	76.7	445.3	2,050.2
⑤Annual consumption (kiloton)	518.9	454.4	257.9	104.4	98.8	90.1	75.3	444.2	2,044.1
⑥Comparison ④/⑤	1.00	1.00	0.99	1.02	1.04	1.01	1.02	1.00	1.00

Source: Authors.

3) Operational status of tankers

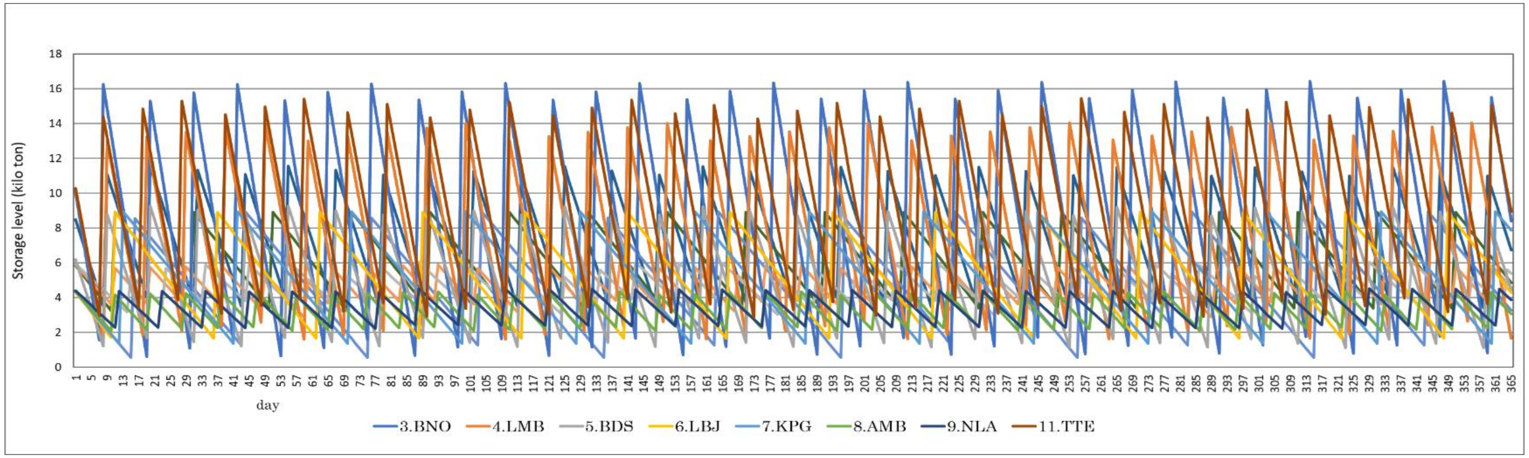
LNG tanker 4 (ship 4) transports LNG to Labuan Bajo & Kupang and LNG tanker 6 (ship 6) delivers LNG to Ambon & Namlea (Figure 7.21) . Due to different LNG demand of the four destinations, the frequency of LNG delivery of ship 4 is higher than ship 6. The operating rate of an LNG tanker for Ambon and Namlea exceeds 80%; however, for Labuan Bajo and Kupang, it is still below 50%.

Table 7.22: Results of Tanker Operation, MSL (Case 2)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
MSL	3.BNO	1	3,719	384	4,201	384	4,969	8,687	57%	32	32
	4.LMB	2	3,091	420	4,638	420	5,478	8,569	64%	35	35
	5.BDS	3	3,152	372	4,791	372	5,535	8,686	64%	31	31
	6.LBJ 7.KPG	4	4,469	360	3,277	360	3,997	8,466	47%	30	30
	8.AMB 9.NLA	6	1,491	864	5,540	864	7,268	8,759	83%	72	72
	11.TTE	8	4,495	420	3,340	420	4,180	8,675	48%	35	35
Total			**20,416**	**2,820**	**25,786**	**2,820**	**31,426**	**51,842**		**235**	**235**

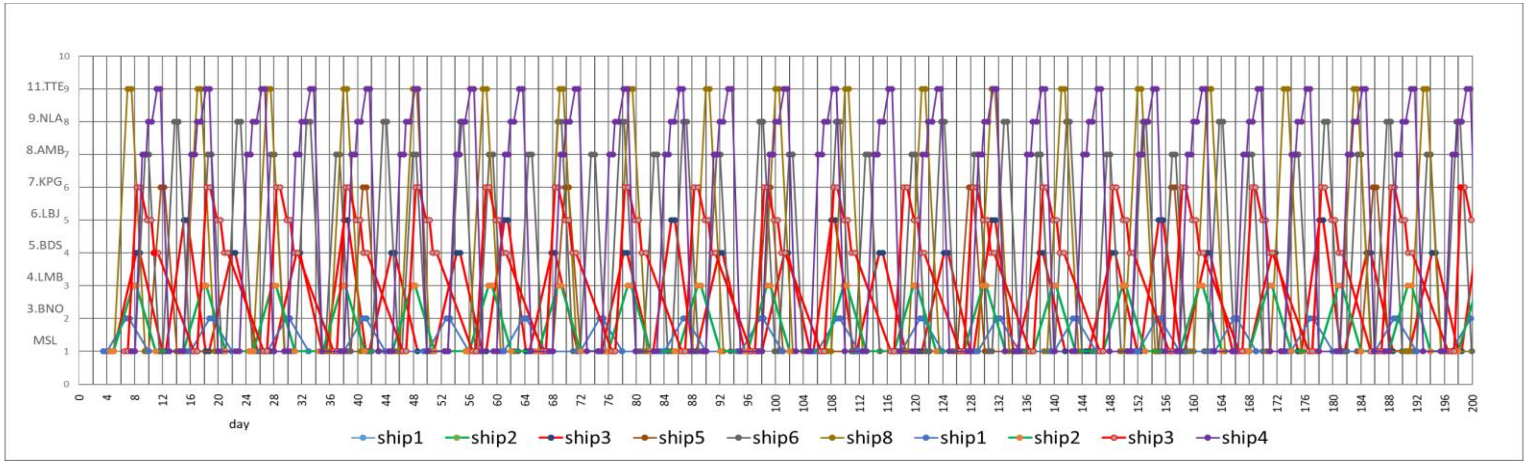
Source: Authors.

Figure 7.20: LNG Storage Level of Onshore Storage, MSL (Case 2)



Source: Authors' analysis.

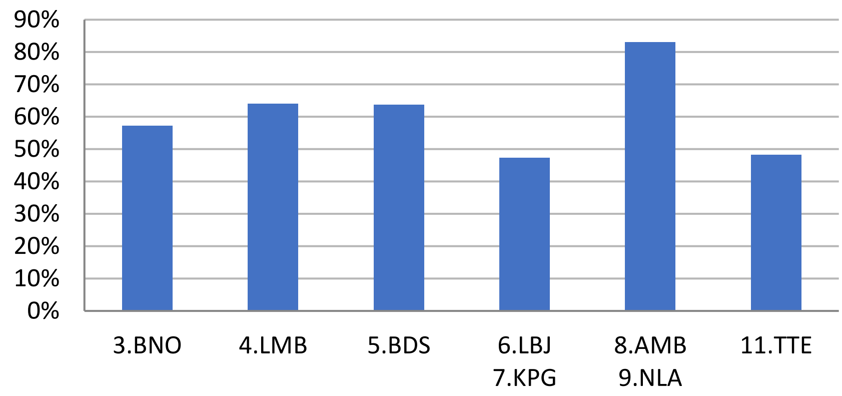
Figure 7.21: Diagram of LNG Tanker Operations, MSK (Case 2)



Source: Authors' analysis.

4) Other information

Figure 7.22: Rate of Tanker Operations, MSL (Case 2)



Source: Authors.

The total operation cost of case 2 is a little bit higher than case 1 because only one LNG tanker delivers LNG to Labuan Bajo and Namlea. The number of unloading in Labuan Bajo and Namlea in case 1 is 14 + 13 = 27. On the other hand, the number of unloading in case 2 is 30 (Tables 7.19 and 7.22). Therefore, the cruising distance x LNG delivery volume of case 2 is bigger than case 1. This is why the operating cost of case 2 is higher than case 1. But the number of LNG tankers of case 2 decreases from eight to six.

Table 7.23 Cruising Distance and OPEX of LNG Tankers, MSL (Case 2)

						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (ound-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/year)**
MSL	3.BNO	L	55,872	515	449,770	5.9	2.65
	4.LMB	M	60,760	443	384,307	5.9	2.27
	5.BDS	S	47,554	257	196,874	5.9	1.16
	6.LBJ 7.KPG	S	40,764	202	118,479	5.9	0.70
	8.AMB 9.NLA	SS	52,974	166	60,920	5.9	0.36
	11.TTE	M	43,610	443	275,833	5.9	1.63
Total			**301,534**	**2,025**	**1,486,183**		**8.77**

Source: Authors.

c. Case 3: milk-run method partly applied

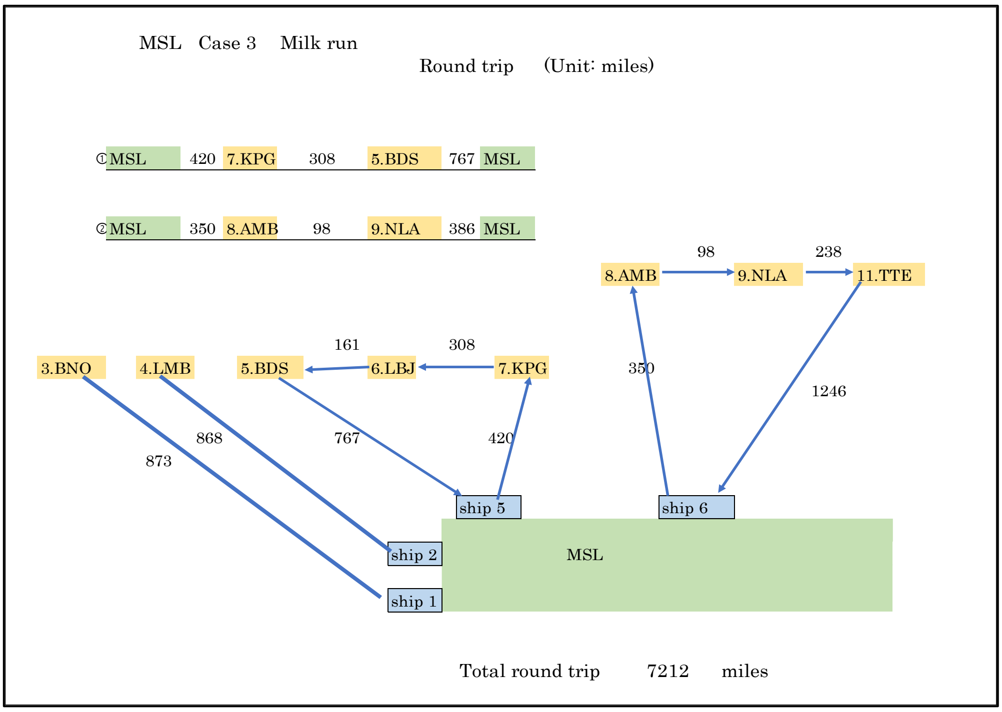
Table 7.17 shows the number and size of LNG tankers of case 3.

1) Operation of LNG tankers

Since the operation rate of the LNG tanker to deliver LNG to Labuan Bajo and Kupang of case 2 is less than 50%, Badas is added to the subgroup of Labuan Bajo and Kupang. Therefore, the milk-run method is applied to a new subgroup to include Kupang, Labuan Bajo, and Badas by one LNG tanker. In addition, the operation rate of Ternate is less than 50% in case 2, so that Ternate is also added to the subgroup of Ambon and Namlea. Then the milk-run method with one LNG tanker is applied to the new subgroup of Ambon, Namlea, and Ternate.

- ✔ Masela–Kupang–Labuan Bajo–Badas–Masela to use M type LNG tanker
- ✔ Masela–Ambon–Namlea–Ternate–Masela to use M type LNG tanker.

Figure 7.23: LNG Delivery, MSL, Milk-Run Method (Case 3)



Source: Authors.

The total cruising distance of case 1 is 9,822 miles; that of case 3 is 7,212 miles. Thus, occasionally, the milk-run method contributes to shortening the cruising distance. However, destinations should be close to each other.

Table 7.24: Comparison of Cruising Distance between Hub & Spoke (Case 1) and Milk-Run Methods (Case 3)

MSL Group	City Name	Hub & Spoke	Milk-Run
		Round Trip	
MSL	3.BNO	1,746	1,746
	4.LMB	1,736	1,736
	5.BDS	1,534	1,656
	6.LBJ	1,242	
	7.KPG	840	
	8.AMB	700	828
	9.NLA	778	
	11.TTE	1,246	1,246
	Total	9,822	7,212

Milk-run area

Source: Authors.

2) Operational status of storage

Due to the application of the milk-run method, the initial volume of the two LNG onshore storages at Badas and Ternate are assumed to be two thirds of its capacity. However, no shortage has occurred. In addition, looking at the ratio defined as 'maximum level/capacity of LNG onshore storage', the ratios of the eight sites are lying about 0.6–0.7 and they look good. But the difference between the maximum and the minimum levels of LNG onshore storage at Labuan Bajo, Kupang, Ambon, and Namlea seem to be narrow. Therefore, the LNG storage capacity might be too big. The SS type of LNG storage could be available (Table 7.25).

Table 7.25: Operational Status of Onshore Storage, MSL (Case 3)

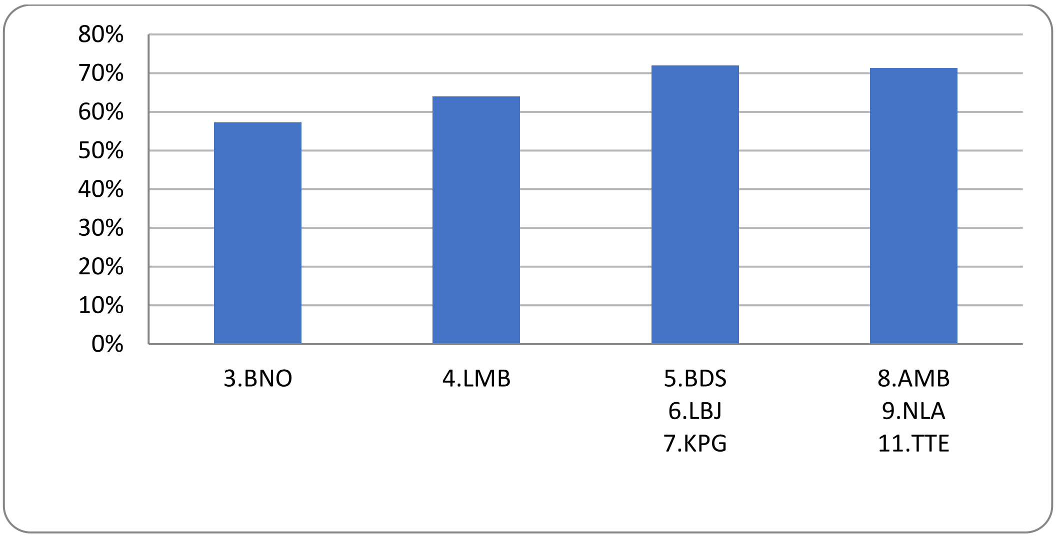
Operational Status of Storage	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	8.AMB	9.NLA	11.TTE	Total
Storage size	L	L	M	S	S	S	S	L	
Storage capacity (CBM)	50,000	50,000	30,000	20,000	20,000	20,000	20,000	50,000	
Storage capacity (kiloton)	23.0	23.0	13.8	9.2	9.2	9.2	9.2	23.0	119.6
①Initial value of storage (kilotons)	11.5	11.5	9.2	6.1	6.1	6.1	6.1	15.3	72.1
②Unloading weight (kiloton/year)	515.2	442.8	253.7	98.8	101.8	89.7	75.9	442.8	2020.6
Tanker unloading volumes (kiloton/time)	16.1	12.7	8.3	8.3	8.3	2.3	2.3	12.7	
Level of calling a tanker (kiloton)	7.67	7.67	6.90	4.60	4.60	4.60	4.60	11.50	
Number of unloading (times)	32	35	36	36	36	48	48	48	319
Maximum level of storage (kiloton)	16.44	14.05	8.49	5.84	6.4	5.88	5.92	14.11	
Minimum level of storage (kiloton)	0.62	1.58	0.34	3.23	3.97	3.85	4.02	1.91	
Average level of storage (kiloton)	8.5	7.8	4.4	4.5	5.2	4.8	4.8	6.8	
Maximum level/Storage capacity	0.71	0.61	0.62	0.63	0.70	0.64	0.64	0.61	
③Stock at end of period (kiloton)	8.4	1.65	4.55	4.68	4.78	5.12	5.32	11.15	45.65
④Total supply (kiloton) ①＋②－③	518.3	452.6	258.4	100.3	103.2	90.7	76.7	446.9	2,047.0
⑤Annual consumption (kiloton)	518.9	454.4	257.9	104.4	98.8	90.1	75.3	444.2	2,044.1
⑥Comparison ④/⑤	1.00	1.00	1.00	0.96	1.04	1.01	1.02	1.01	1.00

Source: Authors.

3) Operational status of LNG tankers

Figure 7.25 shows the operation of four LNG tankers of case 3. The figure also shows the busy situation of LNG tankers or ships 3 and 4, whilst ships 1 and 2 have plenty of idle time. Ship 3 transports LNG from Masela to Badas, Labuan Bajo, and Kupang by the milk-run method. Ship 4 also delivers LNG to Ambon, Namlea, and Ternate by the same method. Thus, the operation rates of both ships increase to 72% and 71%, respectively (Table 7.26).

Figure 7.24: Rate of LNG Tanker Operations, MSL (Case 3)



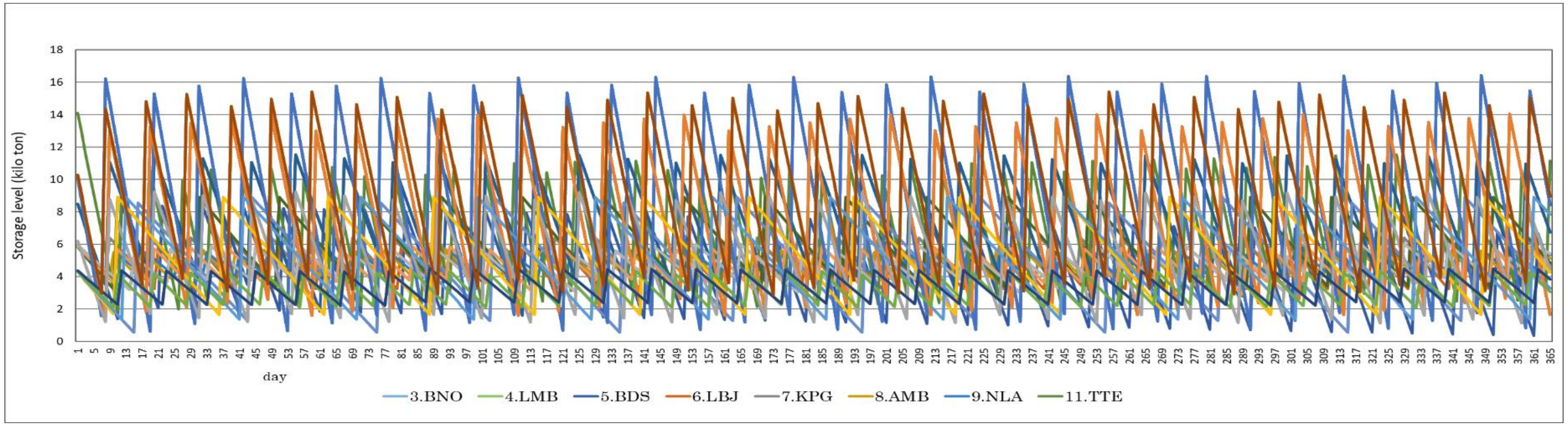
Source: Authors.

Table 7.26: Results of Tanker Operations, MSL, Milk-Run Method (Case 3)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
MSL	3.BNO	1	3,719	384	4,201	384	4,969	8,687	57%	32	32
	4.LMB	2	3,091	420	4,638	420	5,478	8,569	64%	35	35
	5.BDS 6.LBJ 7.KPG	5	2,453	432	4,549	1,296	6,277	8,730	72%	36	108
	8.AMB 9.NLA 11.TTE	6	2,525	576	3,953	1,728	6,257	8,782	71%	48	144
Total			**11,788**	**1,812**	**17,341**	**3,828**	**22,981**	**34,768**		**151**	**227**

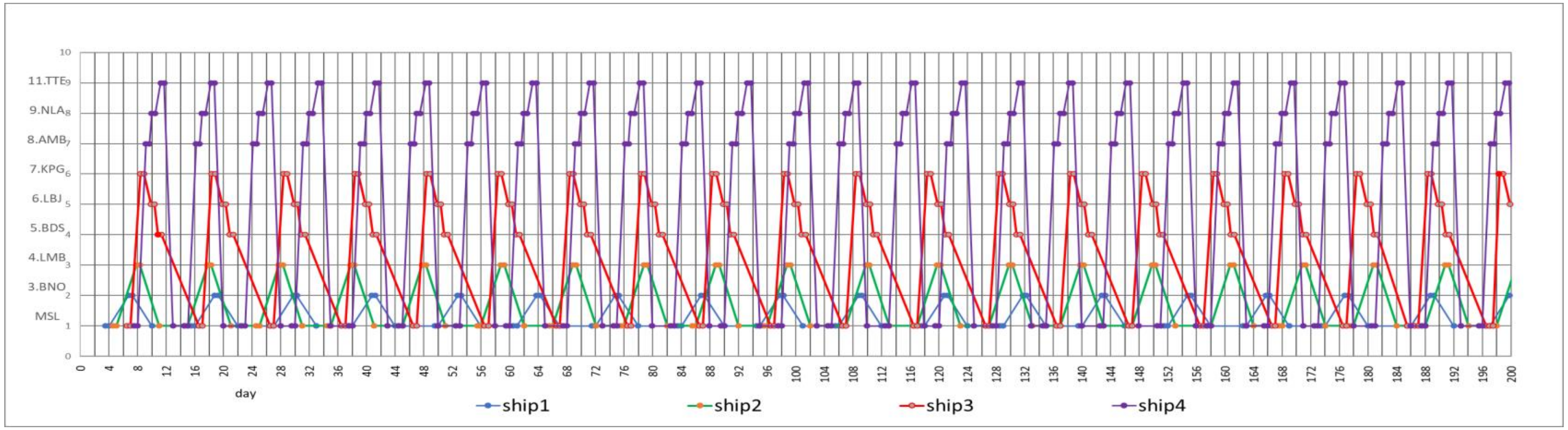
Source: Authors.

Figure 7.25: LNG Storage Level of Each Site, MSL (Case 3)



Source: Authors' analysis.

Figure 7.26: LNG Tanker Operations, MSL (Case 3)



Source: Authors' analysis.

4) Key findings

The total operation cost of case 3 is higher than case 2. But the cruising distance of case 3 is shorter than case 2. Operation cost is defined as tonne mile (distance x unloading of LNG) x unit operation cost of LNG tanker (US$/1,000 tonne miles). Therefore, the tonne miles of case 3 should be bigger than case 2 because the LNG tanker leaving Masela should load roughly three times the LNG amount compared to case 2. But for case 3, LNG tankers are reduced from six to four.

Table 7.27: Cruising Distance and OPEX of LNG Tankers, MSL, Milk-Run Method (Case 3)

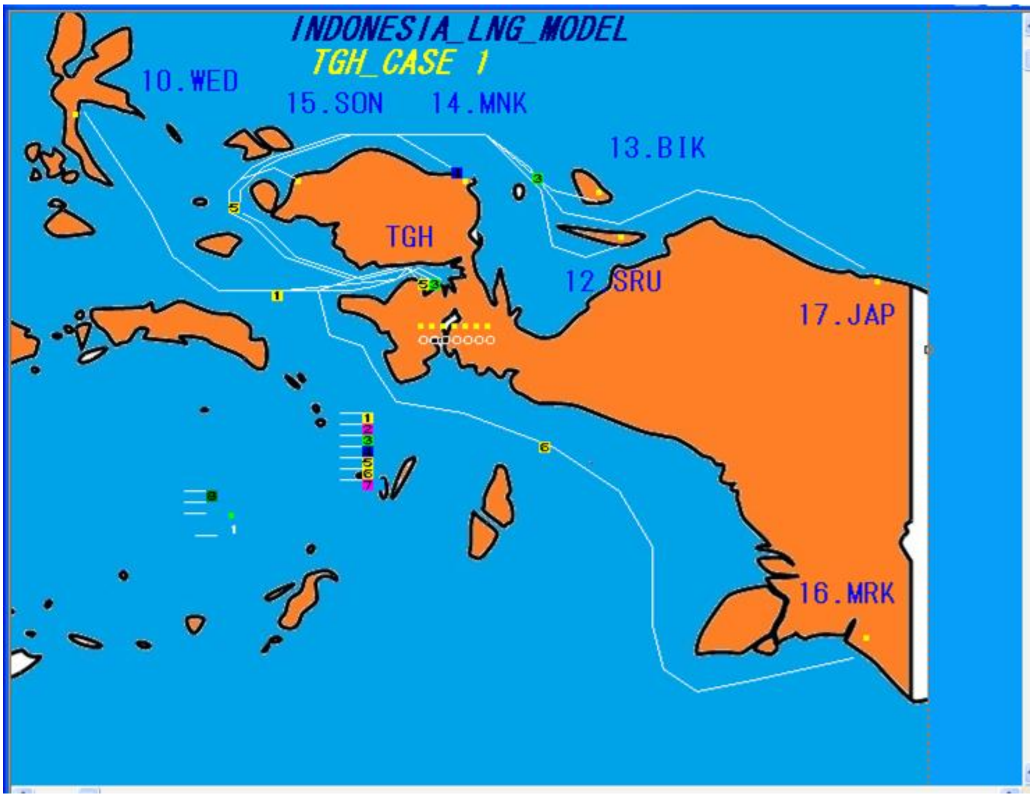
						Tanker OPEX	
Home Port Terminal	Destination	Tanker Size	Cruise Distance (round-trip miles)	Unloading Weight (kiloton)	Tonne Miles (1,000 tonne miles)	Unit Price (US$/1,000 tonne miles)	Ship Operating Costs (million US$/year)
MSL	3.BNO	L	55,872	515	449,770	5.9	2.65
	4.LMB	M	60,760	443	384,307	5.9	2.27
	5.BDS 6.LBJ 7.KPG	M	59,616	455	342,455	5.9	2.02
	8.AMB 9.NLA 11.TTE	M	59,388	607	405,223	5.9	2.39
Total			**235,636**	**2,021**	**1,581,755**		**9.33**

Source: Authors.

2.3. Tangguh group

The Tangguh group consists of one LNG shipping site (Tangguh) and seven LNG receiving sites: Weda, Yapen Island (Serui), Biak, Manokwari, Sorong city, Merauke, and Jayapura city. These are around South Halmahera to Papua province. Figure 7.27 shows the simulation image of LNG delivery from Tangguh to seven LNG receiving sites in the Tangguh group.

Figure 7.27: Simulation of LNG Delivery on PC Screen, TGH, Milk-Run Method (Case 3)



Source: Authors.

Ports of LNG receiving terminal, LNG onshore facility, and LNG tankers

Table 7.28 summarises the water depth at each receiving port, annual LNG consumption, LNG onshore storage capacity, and type of LNG tanker to be initially deployed.

Table 7.28: Input Conditions for Simulation

Production Base	No.	Port Abbreviation	Port Water Depth	Annual Consumption (kiloton)	Onshore Storage			Tanker Storage			
					Type	Capacity (CBM)	Weight (kiloton)	Water Depth (m)	Type	Capacity (CBM)	Weight (kiloton)
TGH	10	WED	―	454	L	50,000	23.00	6.05	S	18,000	8.28
	12	SRU	10	23	SS	5,000	2.30	5.28	SS	5,000	2.30
	13	BIK	9	36	SS	5,000	2.30	5.28	SS	5,000	2.30
	14	MNK	12	154	S	20,000	9.20	6.05	S	18,000	8.28
	15	SON	15	247	M	30,000	13.80	6.05	S	18,000	8.28
	16	MRK	7	51	SS	5,000	2.30	5.28	SS	5,000	2.30
	17	JAP	9	23	SS	5,000	2.30	5.28	SS	5,000	2.30

Source: Authors.

Table 7.29 shows the number and types of LNG tankers deployed for each case. Four SS-type LNG tankers and three S-type LNG tankers are assigned to case 1. Case 2 reduces the number of LNG tankers from seven to five. These are three SS-type and two S-type LNG tankers. Case 3 assigns only three LNG tankers consisting of SS, S, and M types.

Table 7.29: Number and Size of Tanker (Cases 1–3)

	TGH						
	10.WED	**12.SRU**	**13.BIK**	**14.MNK**	**15.SON**	**17.JAP**	**16.MRK**
Case 1	S	SS	SS	S	S	SS	SS
Case 2	S	SS		S		SS	SS
Case 3	S	M					SS

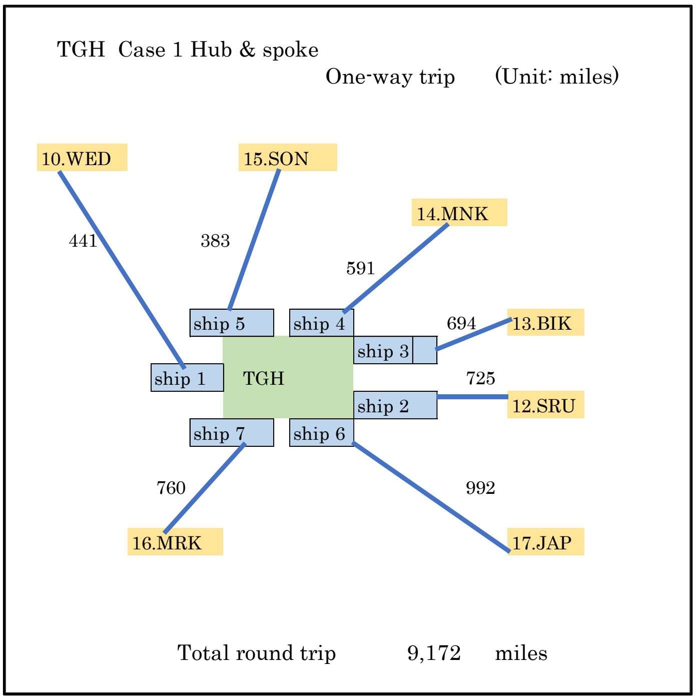
Source: Authors.

a. Case 1: Hub & spoke method

1) Image of LNG tanker operation

Case 1 allocates seven ships to seven routes for delivering LNG from Tangguh to seven destination ports. Figure 7.28 shows the image of case 1.

Figure 7.28: Image of LNG Delivery from TGH, Hub & Spoke Method (Case 1)



Source: Authors.

2) Operational status of LNG onshore storage

The simulation results of LNG onshore storages at seven LNG receiving ports are shown in Table 7.30 and Figure 7.29, indicating the following:

- The initial volume of each onshore storage is assumed half of its capacity, but no shortage has happened at the seven receiving ports.
- The storage capacity at Serui and Biak with 5,000 CBM, Manokwari with 20,000 CBM, Merauke and Jayapura with 5,000 CBM is appropriate, as indicated by ‘maximum level/LNG storage capacity’. The indicators of the four LNG receiving sites are more than 90%.
- On the other hand, the storage capacity of Weda with 50,000 CBM and Sorong with 30,000 CBM is oversized due to lower indicators defined as ‘maximum level/LNG storage capacity’.
- Considering the ‘minimum level of LNG storage’ of the three sites – Weda, Manokwari, and Sorong city – and considering these to be less than a few days, increasing the initial volume of the LNG storage is recommended.

Table 7.30: Operational Status of Onshore Storage, TGH (Case 1)

Operational Status of Storage	10.WED	12.SRU	13.BIK	14.MNK	15.SON	16.MRK	17.JAP	Total
Storage size	L	SS	SS	S	M	SS	SS	
Storage capacity (CBM)	50,000	5,000	5,000	20,000	30,000	5,000	5,000	
Storage capacity (kiloton)	23.0	2.3	2.3	9.2	13.8	2.3	2.3	55.2
①Initial value of storage (kilotons)	11.5	1.2	1.2	4.6	6.9	1.2	1.2	27.6
②Unloading weight (kiloton/year)	447.1	21.8	37.4	157.1	248.4	50.4	22.5	984.6
Tanker unloading volumes (kiloton/time)	8.3	2.3	2.3	8.3	8.3	2.3	2.3	
Level of calling a tanker (kiloton)	5.75	0.58	0.58	2.30	3.45	0.77	0.58	
Number of unloading (times)	54	11	17	19	30	24	11	166
Maximum level of	10.26	2.24	2.2	8.78	8.98	2.16	2.24	

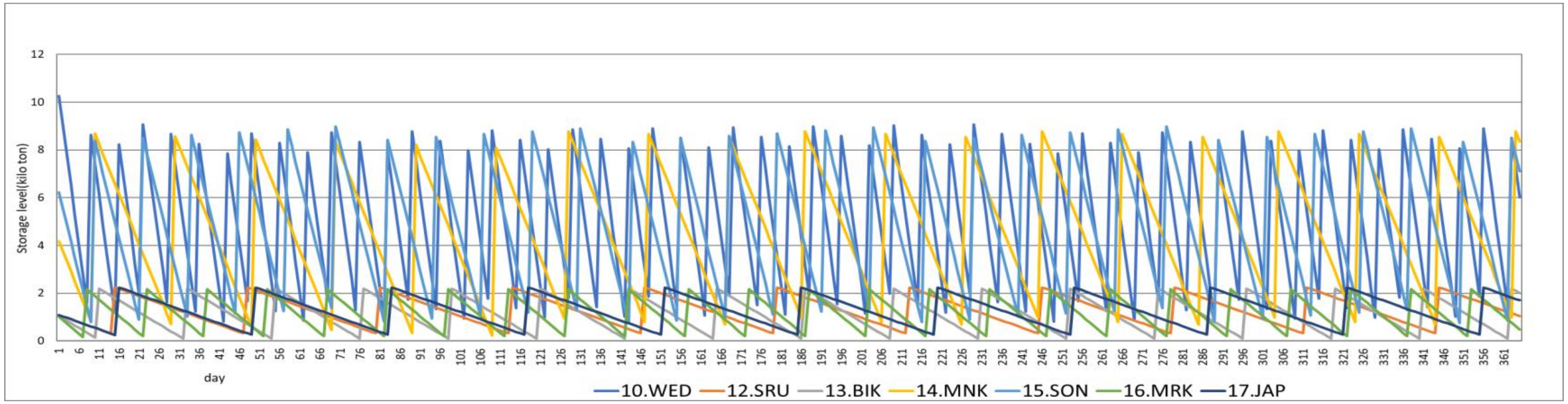
storage (kiloton)								
Minimum level of storage (kiloton)	0.82	0.31	0.1	0.22	0.74	0.17	0.25	
Average level of storage (kiloton)	5.0	1.3	1.1	4.6	4.8	1.2	1.2	
Maximum level/Storage capacity	0.45	0.97	0.96	0.95	0.65	0.94	0.97	
③Stock at end of period (kiloton)	6.02	1.04	2	8.36	7.1	0.48	1.7	26.7
④Total supply (kiloton) ①＋②－③	452.6	21.9	36.5	153.3	248.2	51.1	21.9	985.5
⑤Annual consumption （kiloton）	454.0	23.4	35.6	154.1	247.1	51.2	22.9	988.3
⑥Comparison ④/⑤	1.00	0.94	1.03	0.99	1.00	1.00	0.96	1.00

Source: Authors.

3) Operational status of tankers

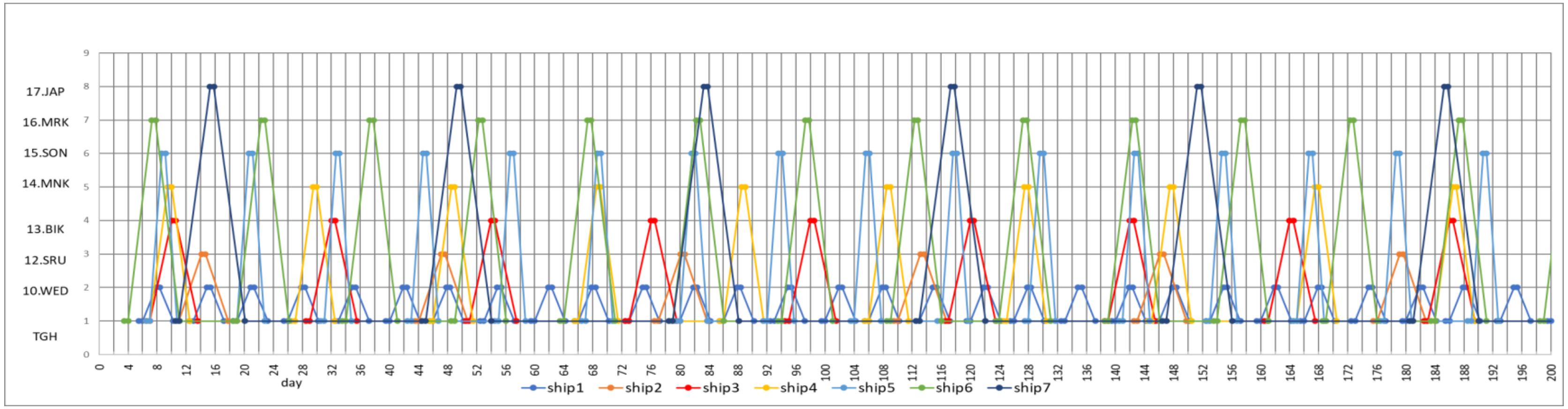
Figure 7.29 shows the operation of seven tankers. Table 7.31 shows the operation status of LNG tanker per each route, including waiting time, loading time, transporting time, unloading time, operating time, total time, operating rate, and number of loading and unloading of LNG. The operation rate of LNG tankers on five routes – Serui, Biak, Monokwari, Sorong, and Jayapura – is quite low. This suggests improving the operation rate through the application of other methods.

Figure 7.29: **LNG Storage Level of Each Site, TGH (Case 1)**



Source: Authors' analysis.

Figure 7.30: LNG Tanker Operations, TGH (Case 1)



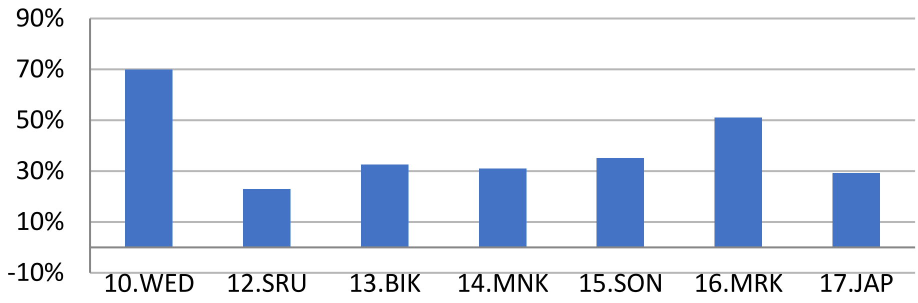
Source: Authors' analysis.

Table 7.31: Results of Tanker Operations, TGH, Hub & Spoke Method (Case 1)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
TGH	10.WED	1	2,628	648	4,817	648	6,113	8,741	70%	54	54
	12.SRU	2	6,427	132	1,655	132	1,919	8,346	23%	11	11
	13.BIK	3	5,911	204	2,453	204	2,861	8,772	33%	17	17
	14.MNK	4	6,070	228	2,269	228	2,725	8,795	31%	19	19
	15.SON	5	5,675	360	2,336	360	3,056	8,731	35%	30	30
	16.MRK	6	4,179	288	3,791	288	4,367	8,546	51%	24	24
	17.JAP	7	6,112	132	2,266	132	2,530	8,642	29%	11	11
Total			**37,002**	**1,992**	**19,587**	**1,992**	**23,571**	**60,573**	**39%**	**166**	**166**

Source: Authors.

Figure 7.31: Rate of Tanker Operation, TGH (Case 1)



Source: Authors.

4) Key findings

The operation cost of LNG delivery to Weda is more than US$1 million per year. That of other ports is less than US$1 million due to shorter cruising distances and smaller LNG amounts.

Table 7.32: Cruising Distance and OPEX of LNG Tanker, TGH, Hub & Spoke Method (Case 1)

						Tanker OPEX	
Home Port Terminal	Destination	Tanker Size	Cruise Distance (round-trip miles)	Unloading Weight (kiloton)	Tonne Miles (1,000 tonne miles)	Unit Price (US$/1,000 tonne miles)	Ship Operating Costs (million US$/year)
TGH	10.WED	S	47,628	447	197,180	5.9	1.16
	12.SRU	SS	15,950	22	15,798	5.9	0.09
	13.BIK	SS	23,596	37	25,921	5.9	0.15
	14.MNK	S	22,458	157	92,822	5.9	0.55
	15.SON	S	22,980	248	95,137	5.9	0.56
	16.MRK	SS	36,480	50	38,327	5.9	0.23
	17.JAP	SS	21,824	22	22,270	5.9	0.13
Total			**190,916**	**985**	**487,455**		**2.88**

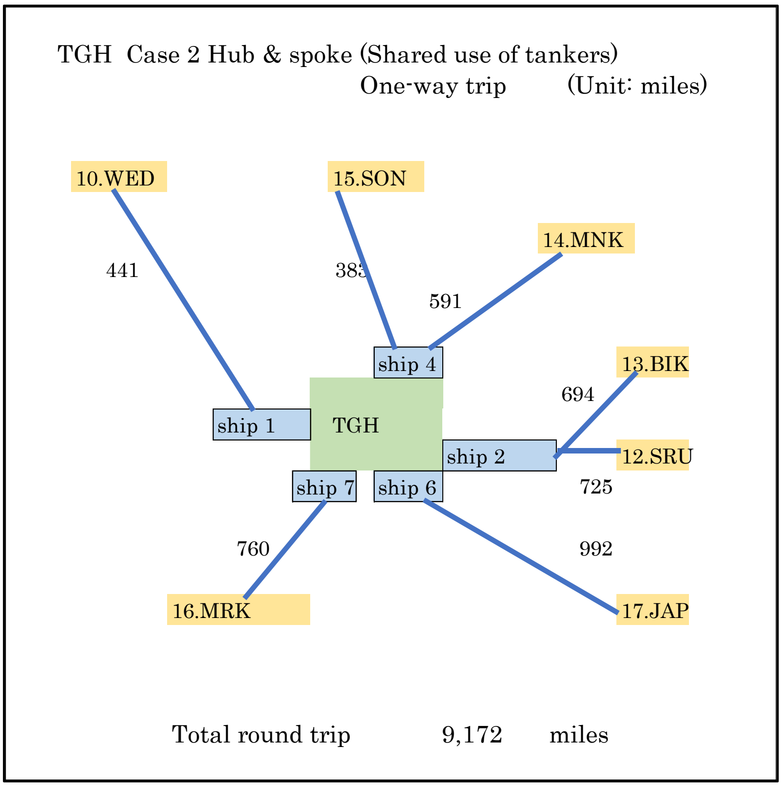
Source: Authors.

b. Case 2: LNG tanker sharing method (partly applied)

1) Image of LNG tanker operation

Figure 7.32 shows the operation of LNG tankers of case 2. LNG tanker ship 2 covers two LNG demand sites, Serui and Biak. Another LNG tanker, ship 4, delivers LNG to Manokwari and Sorong city. As a result, the number of LNG tankers decreased from seven to five.

Figure 7.32: Delivery from LNG Terminal, TGH, Hub & Spoke (Case 2)



Source: Authors.

2) Operational status of LNG onshore storage

The initial volume of the four ports (Serui, Biak, Manokwari, and Sorong) increases from one half to two thirds due to the operation of one LNG tanker. The capacities of the ports do not change because no LNG shortage occurs. In addition, the LNG storage capacity at Weda and Manokwari seems to be bigger compared to the actual storage level, defined as the difference between the maximum and the minimum levels. Weda has a 23-kiloton capacity less 10 kilotons as minimum level. Manokwari's capacity is 9.2 kilotons less 6.7 kilotons minimum level (Table 7.33 and Figure 7.33).

Table 7.33: Operational Status of Onshore Storage, TGH (Case 2)

Operational Status of Storage	10.WED	12.SRU	13.BIK	14.MNK	15.SON	16.MRK	17.JAP	Total
Storage size	L	SS	SS	S	M	SS	SS	
Storage capacity (CBM)	50,000	5,000	5,000	20,000	30,000	5,000	5,000	
Storage capacity (kiloton)	23.0	2.3	2.3	9.2	13.8	2.3	2.3	55.2
①Initial value of storage (kilotons)	11.5	1.5	1.5	6.1	9.2	1.2	1.2	32.2
②Unloading weight (kiloton/year)	447.1	21.7	37.3	152.5	248.4	50.4	22.5	979.9
Tanker unloading volumes (kiloton/time)	8.3	2.3	2.3	8.3	8.3	2.3	2.3	
Level of calling a tanker (kiloton)	5.75	1.15	1.15	4.60	6.90	0.77	0.58	
Number of unloading (times)	54	14	20	25	30	24	11	178
Maximum level of storage (kiloton)	10.26	2.24	2.2	8.78	12.44	2.16	2.24	
Minimum level of storage (kiloton)	0.82	0.5	0.1	2.06	0.36	0.17	0.25	
Average level of storage (kiloton)	5.0	1.4	1.3	5.9	6.9	1.2	1.2	
Maximum level/Storage capacity	0.45	0.97	0.96	0.95	0.90	0.94	0.97	
③Stock at end of period (kiloton)	6.02	2.18	0.6	6.26	9.4	0.48	1.7	26.64
④Total supply (kiloton) ①＋②－③	452.6	21.1	38.2	152.4	248.2	51.1	22.0	985.5
⑤Annual consumption (kiloton)	454.0	23.4	35.6	154.1	247.1	51.2	22.9	988.3
⑥Comparison ④/⑤	1.00	0.90	1.07	0.99	1.00	1.00	0.96	1.00

Source: Authors.

3) Operational status of tankers

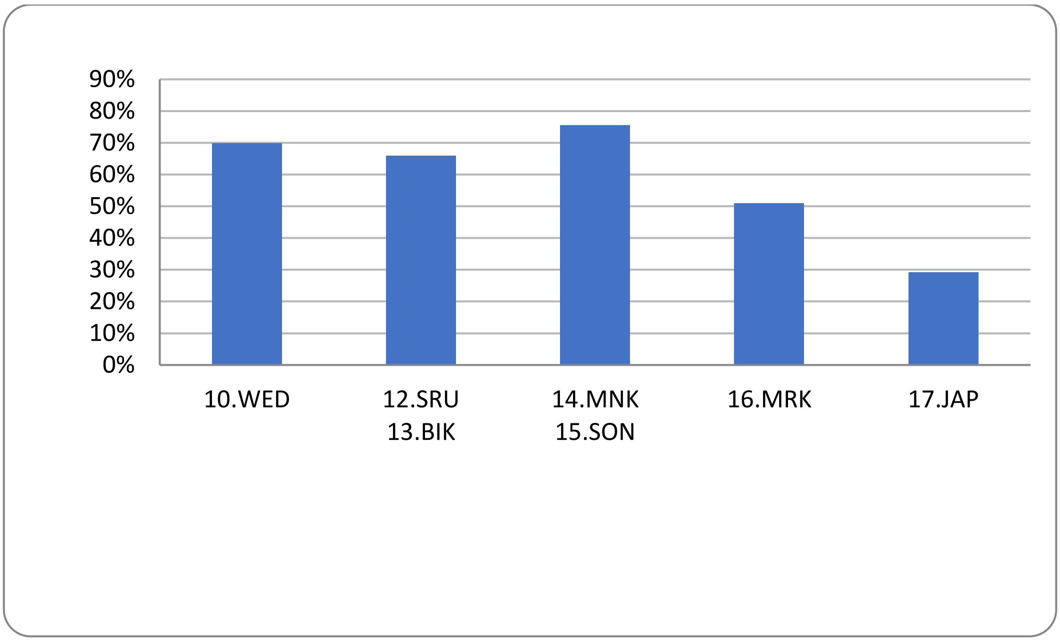
The operation rate of LNG tankers, ships 2 and 4, improves largely due to LNG delivery by one tanker to two LNG demand sites.

Table 7.34: Results of LNG Tanker Operations, Hub & Spoke (Case 2)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
TGH	10.WED	1	2,628	648	4,817	648	6,113	8,741	70%	54	54
	12.SRU 13.BIK	2	2,994	408	4,994	408	5,810	8,803	66%	34	34
	14.MNK 15.SON	4	2,148	660	5,309	660	6,629	8,777	76%	55	55
	16.MRK	6	4,182	288	3,788	288	4,364	8,546	51%	24	24
	17.JAP	7	6,113	132	2,265	132	2,529	8,642	29%	11	11
Total			**18,064**	**2,136**	**21,172**	**2,136**	**25,444**	**43,509**	**58%**	**178**	**178**

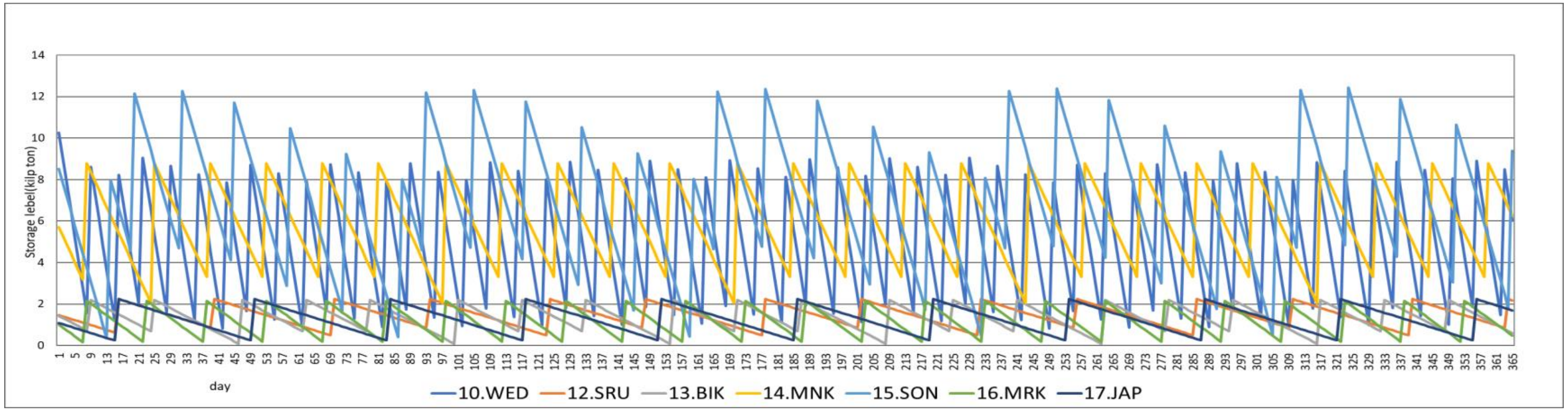
Source: Authors.

Figure 7.33: Rate of LNG Tanker Operation, TGH (Case 2)



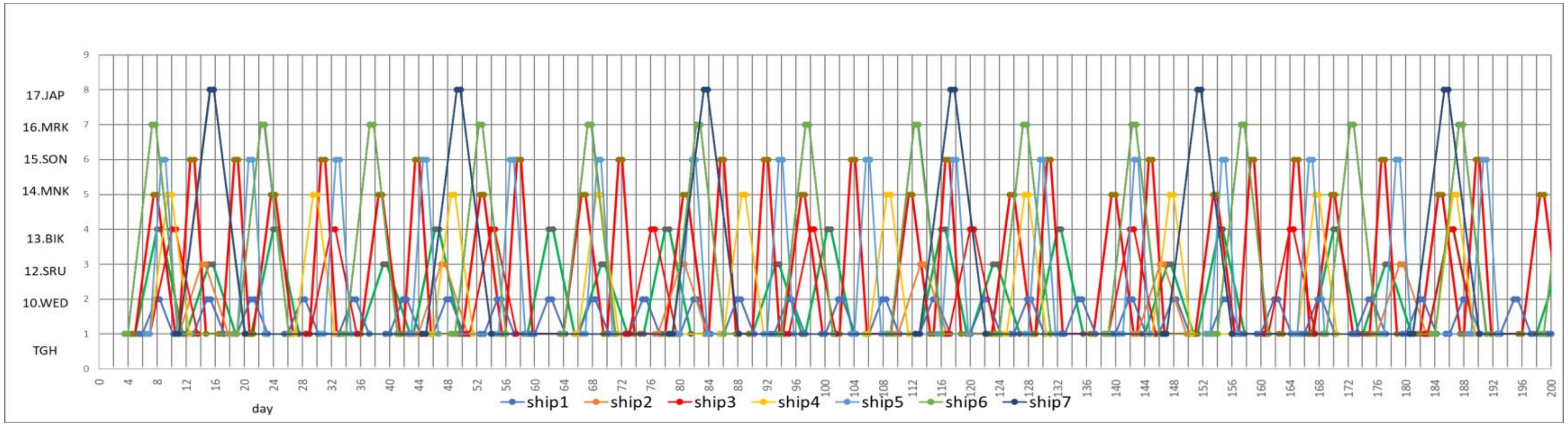
Source: Authors.

Figure 7.34: LNG Storage Level of Each Site, TGH (Case 2)



Source: Authors' analysis.

Figure 7.35: LNG Tanker Operation, TGH (Case 2)



Source: Authors' analysis.

4) Key findings

The total operation cost of LNG tankers of case 2 is similar to case 1 due to the application of the same delivery method, which is hub & spoke. But cases 1 and 2 have different assumptions, which are the initial volume at LNG storages and LNG tanker calling level. Thus, the unloading amount of LNG to Manokwari is smaller than case 1. This is why the operation costs between cases 1 and 2 are different.

Table 7.35: Cruising Distance and OPEX of LNG Tanker, TGH (Case 2)

						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (round-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/year)**
TGH	10.WED	S	47,628	447	197,180	5.9	1.16
	12.SRU 13.BIK	SS	48,060	58	41,034	5.9	0.24
	14.MNK 15.SON	S	52,530	402	185,814	5.9	1.10
	16.MRK	SS	36,480	50	38,327	5.9	0.23
	17.JAP	SS	21,824	22	22,270	5.9	0.13
Total			**206,522**	**980**	**484,626**		**2.86**

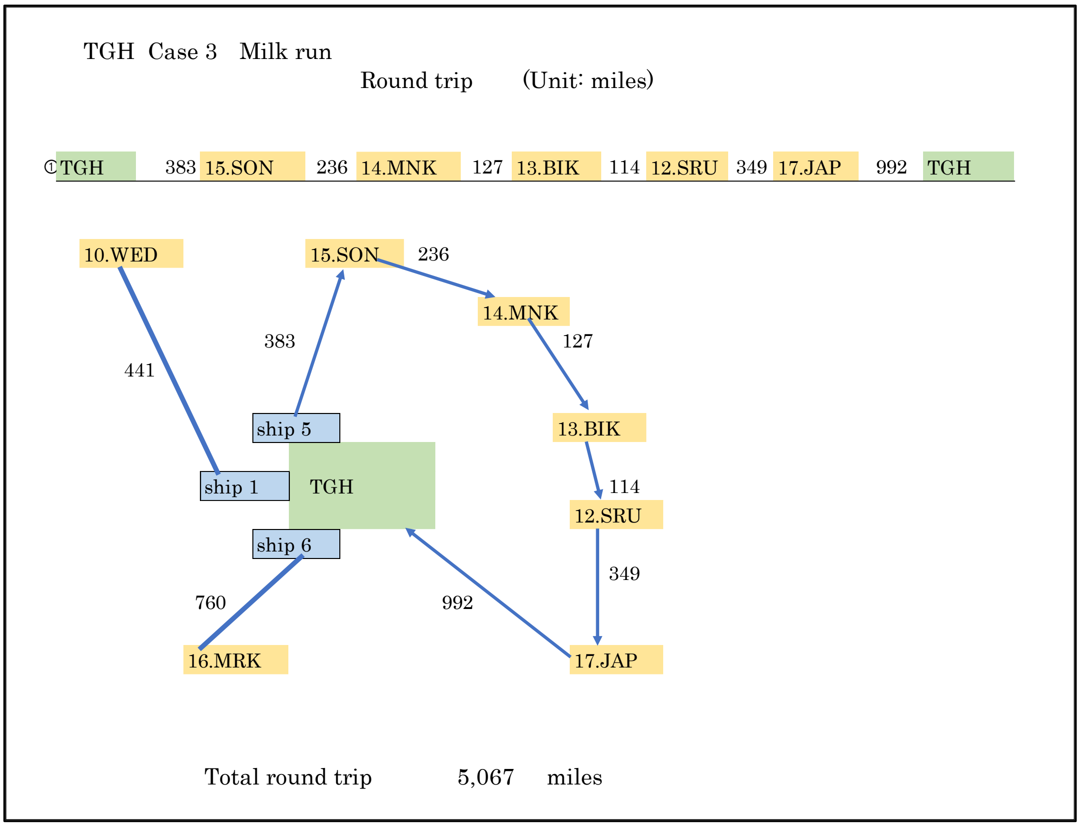
Source: Authors.

c. Case 3: Milk-run method (partly applied)

1) Image of tanker operation

The milk-run method is applied to LNG delivery for Tangguh → Sorong→ Manokwari → Biak → Serui → Jayapura → Tangguh (Figure 7.36).

Figure 7.36: Image of LNG Delivery, TGH, Milk-Run Method (Case 3)



Source: Authors.

In the hub & spoke method, the cruising distance is 9,172 miles (case 1). On the other hand, it is 4,603 miles in the milk-run method (case 3).

Table 7.36: Comparison of Distance of Hub & Spoke and Milk-Run Methods

TGH Group	City Name	Hub & Spoke	Milk-Run
		Round Trip	
TGH	10.WED	882	882
	12.SRU	1,450	2,201
	13.BIK	1,388	
	14.MNK	1,182	
	15.SON	766	
	17.JAP	1,984	
	16.MRK	1,520	1,520
	Total	9,172	4,603

Milk-run area

Source: Authors.

2) Operational status of storage

The initial volume of seven receiving terminals are the same as case 2, except for Jayapura whose volume increased from 1.2 kilotons to 1.5 kilotons due to one of the target ports of the milk-run method. In case 3, one M-type LNG tanker covers five LNG receiving terminals, so that the LNG unloading volume per time is also smaller than case 2 except for Sorong. Due to reduced unloading LNG amount, the number of unloading times increases to 30 times in each port; it is the same for Sorong in case 2. The capacity of LNG onshore storage at Weda, Merauke, and Sorong is oversized, referring to the difference between the maximum and the minimum levels, and can be further reduced.

Table 7.37: Operational Status of Onshore Storage, TGH (Case 3)

Operational Status of Storage	10.WED	12.SRU	13.BIK	14.MNK	15.SON	16.MRK	17.JAP	Total
Storage size	L	SS	SS	S	M	SS	SS	
Storage capacity (CBM)	50,000	5,000	5,000	20,000	30,000	5,000	5,000	
Storage capacity (kiloton)	23.0	2.3	2.3	9.2	13.8	2.3	2.3	55.2
①Initial value of storage (kilotons)	11.5	1.5	1.5	6.1	9.2	1.2	1.5	32.6
②Unloading weight (kiloton/year)	447.1	21.7	37.3	152.5	248.1	50.4	22.5	979.7
Tanker unloading volumes (kiloton/time)	8.3	0.7	1.2	5.1	8.3	2.3	0.7	
Level of calling a tanker (kiloton)	5.75	1.15	1.15	4.60	6.90	0.77	1.15	
Number of unloading (times)	54	30	30	30	30	24	30	228
Maximum level of storage (kiloton)	10.26	1.69	1.91	8.13	13.12	2.16	1.57	
Minimum level of storage (kiloton)	0.82	0.92	0.71	2.99	4.96	0.17	0.8	
Average level of storage (kiloton)	5.0	1.3	1.3	5.6	9.0	1.2	1.2	
Maximum level/Storage capacity	0.45	0.73	0.83	0.88	0.95	0.94	0.68	
③Stock at end of period (kiloton)	6.02	1.53	1.63	6.43	9.86	0.48	0.8	26.75

④Total supply (kiloton) ①＋②－③	452.6	21.7	37.2	152.2	247.5	51.1	23.2	985.5
⑤Annual consumption (kiloton)	454.0	23.4	35.6	154.1	247.1	51.2	22.9	988.3
⑥Comparison ④/⑤	1.00	0.93	1.05	0.99	1.00	1.00	1.01	1.00

Source: Authors.

3) Operational status of LNG tankers

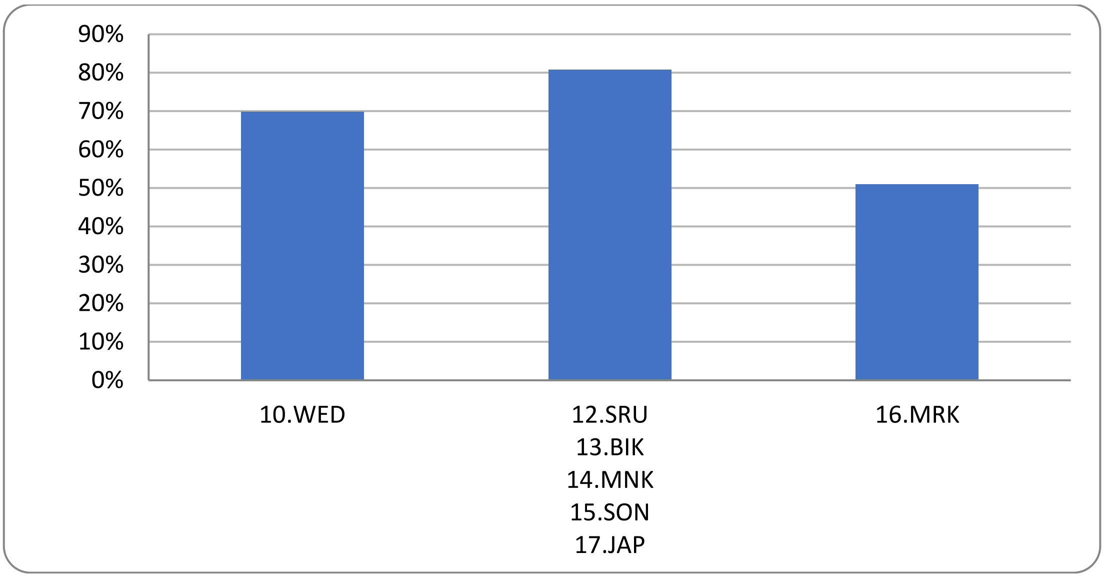
The operational status of LNG tankers is shown in Table 7.38 and the diagram of the operation of the three LNG tankers in the Tangguh Group is shown in Figure 7.38. The occupancy rate increased to 81% due to the application of the milk-run method in five LNG receiving sites. Therefore, one M-sized tanker operation is feasible because of the absence of LNG shortage.

Table 7.38: Results of LNG Tanker Operations, TGH, Milk-Run Method (Case 3)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
TGH	10.WED	1	2,640	648	4,805	648	6,101	8,741	70%	54	54
	12.SRU 13.BIK 14.MNK 15.SON 17.JAP	5	1,683	360	4,899	1,788	7,047	8,730	81%	30	149
	16.MRK	6	4,189	288	3,781	288	4,357	8,545	51%	24	24
Total			**8,512**	**1,296**	**13,485**	**2,724**	**17,505**	**26,016**	**67%**	**108**	**227**

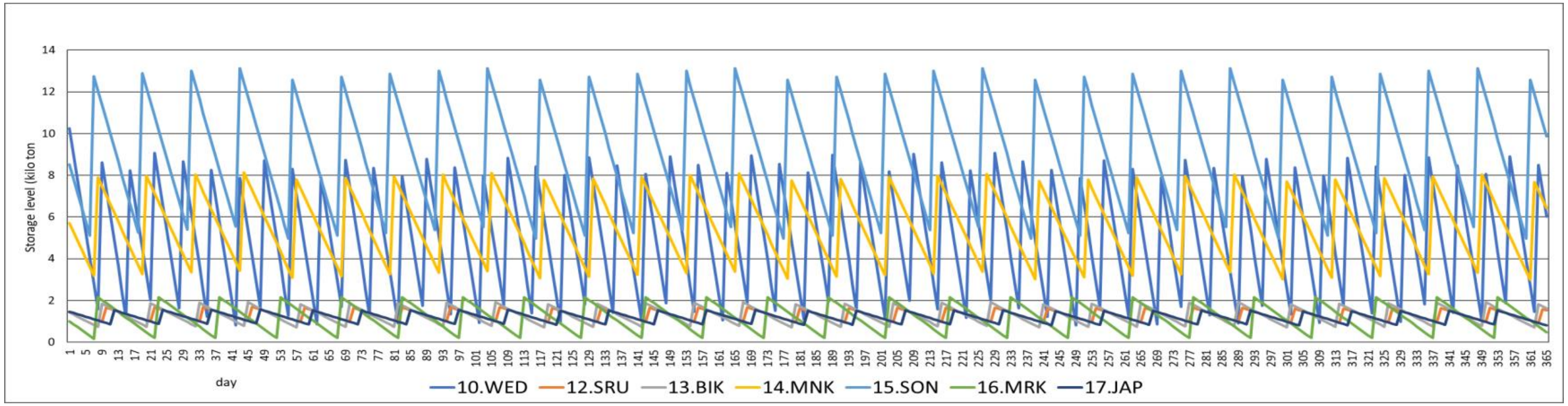
Source: Authors.

Figure 7.37: Rate of Tanker Operation, TGH (Case 3)



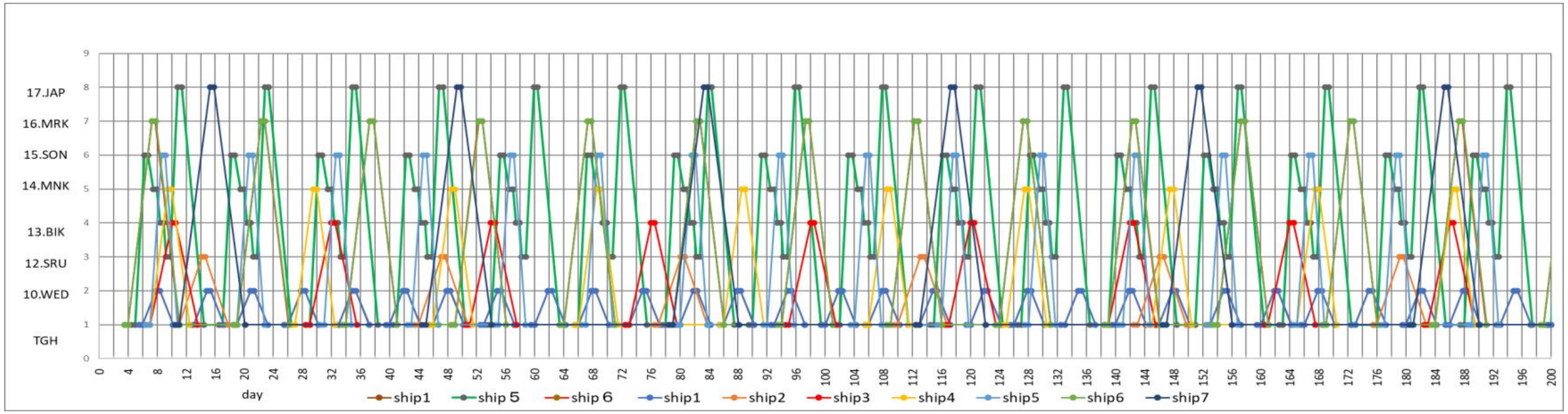
Source: Authors.

Figure 7.38: LNG Storage Level of Each Site, TGH (Case 3)



Source: Authors' analysis.

Figure 7.39: LNG Tanker Operation, TGH (Case 3)



Source: Authors' analysis.

4) Key findings

The operation cost of case 3 is higher than cases 1 and 2. The cruising distance of the ship is shorter than cases 1 and 2, but the tonne miles are more than cases 1 and 2 because one ship has to load a bigger LNG amount than cases 1 and 2 to deliver LNG to five ports. But the increase of operation costs is only 2% from case 1.

Table 7.39: Cruising Distance and OPEX of Tanker, TGH, Milk-Run Method (Case 3)

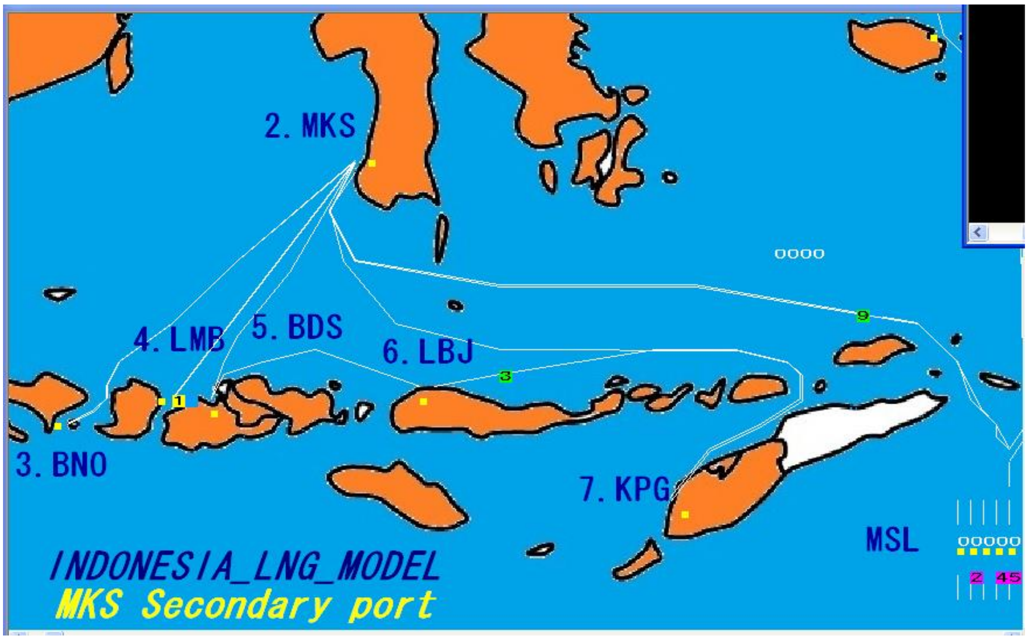
						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (round-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/year)**
TGH	10.WED	S	48,227	447	197,180	5.9	1.16
	12.SRU 13.BIK 14.MNK 15.SON 17.JAP	M	65,368	482	262,921	5.9	1.55
	16.MRK	SS	36,983	50	38,327	5.9	0.23
Total			**150,578**	**980**	**498,428**		**2.94**

Source: Authors.

3. Application of a Secondary Terminal

This section analyses the technical and economic impacts brought about by the application of a secondary terminal system. We assume the secondary port at Makassar in the Masela group covers the following five LNG receiving ports: Bali (Benoa), Lombok (Lembar), Sumbawa (Badas), Flores (Labuan Bajo), and Kupang. Figure 7.40 shows the simulation execution screen on a PC screen.

Figure 7.40: Simulation of LNG Delivery on PC Screen (Secondary Terminal)



Source: Authors.

a. Necessary additional data

1) Distance table

For this analysis, data on two distances are needed: (i) between Masela and Makassar and (ii) between Makassar and the five LNG receiving sites. The distance from Masela and Makassar for each port is less than one half except for Kupang. This surely reduces the operation cost of the LNG tankers. At Makassar, an LL-sized secondary LNG storage is assumed; it covers the LNG consumption at Makassar and the five receiving sites. Makassar never receives LNG from Donggi Senoro.

Table 7.40: Distance from Masera to Makassar and Makassar to the Five Ports

	2	3	4	5	6	7
Base	2.MKS	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG
MSL	695	873	868	767	621	420
2. MKS	—	324	311	298	207	441

Source: Authors.

2) Capacity of a new secondary storage at Makassar

The secondary terminal covers five LNG receiving terminals, which are Bali to Kupang and Makassar. LNG demand and annual LNG delivery amount is 1,624 kilotons. This simulation assumes a 180,000 CBM capacity.

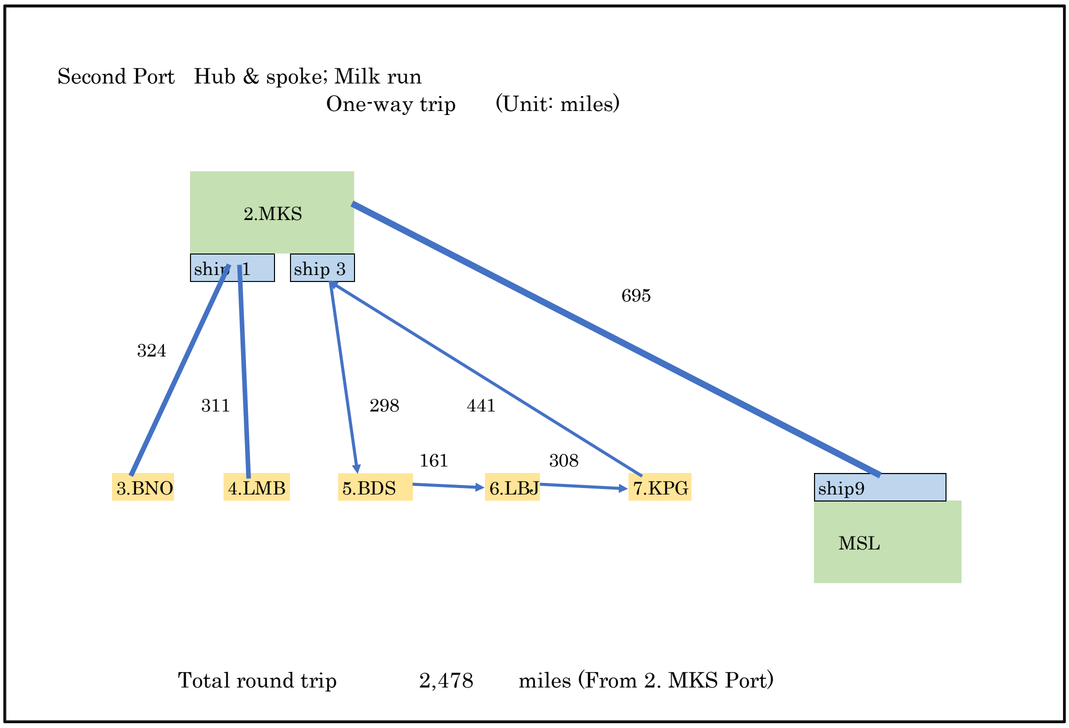
3) Additional LNG tanker between Masela - Makassar

We assume a 70,000 CBM capacity of the secondary super L-type LNG tanker.

b. Operation of the LNG tankers

Figure 7.41 shows the operation of LNG tankers. One super large LNG tanker transports LNG from Masala to the secondary terminal at Makassar. One L-type LNG tanker is assigned to deliver LNG from the secondary terminal at Makassar to Bali and Lombok applying the hub & spoke method, respectively. On the other hand, one M-type LNG tanker covers three ports – Badas, Labuan Bajo, and Kupang – applying the milk-run method. The milk-run method contributes to the reduction of the cruising distance of around 700 miles compared to the hub & spoke method (Table 7.41).

Figure 7.41: LNG Delivery, Secondary Port (Milk-Run Method Partially Applied)



Source: Authors.

Table 7.41: Comparison of Distance of Hub & Spoke and Milk-Run Methods

Secondary Port	City Name	H&S	Milk-Run
		round-trip	
2. MKS	3.BNO	648	648
	4.LMB	622	622
	5.BDS	596	
	6.LBJ	414	1,208
	7.KPG	882	
	Total	**3,162**	**2,478**

H&S = hub & spoke.
Source: Authors.

c. Simulation results

1) Operational status of the storages

- The initial volume of each LNG receiving site is assumed to be two thirds of its storage capacity. But the initial volume of the secondary terminal is assumed to be three fourths of its capacity due to the long-distance cruise of the LNG tanker.
- The storage capacity of each port is appropriate because the ratio defined as maximum level divided by storage capacity at the ports is high.
- Figure 7.42 shows each LNG storage, including the secondary LNG storage. No shortage has happened and remarkable spare capacities of Bali, Lombok, and the secondary terminal are recognised.

Table 7.42: Operational Status of LNG Onshore Storage (Secondary Terminal)

Operational Status of Storage	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	2.MKS
Storage size	L	L	M	S	S	LL
Storage capacity (CBM)	50,000	50,000	30,000	20,000	20,000	150,000
Storage capacity (kiloton)	23.0	23.0	13.8	9.2	9.2	69.0
①Initial value of storage (kilotons)	15.3	15.3	9.2	6.1	6.1	51.8
②Unloading weight (kiloton/year)	518.7	442.8	260.9	107.3	97.2	1642.2
Tanker unloading volumes (kiloton/time)	12.65	12.65	7.05	2.90	2.70	32.20
Level of calling a tanker (kiloton)	11.5	11.5	6.9	4.6	4.6	46.0
Number of unloading (times)	41	35	37	37	36	51
Maximum level of storage (kiloton)	19.84	20.36	11.81	7.58	7.21	68.1
Minimum level of storage (kiloton)	4.48	4.21	4.79	4.1	3.97	9.51
Average level of storage (kiloton)	13.1	13.3	8.3	5.8	5.6	42.9
Maximum level / Storage capacity	0.86	0.89	0.86	0.82	0.78	0.99
③Stock at end of period (kiloton)	15.68	5.48	10.9	7.58	4.78	22.65
④Total supply (kiloton) ①＋②－③	518.3	452.6	259.2	105.9	98.6	1,671.4
⑤Annual consumption (kiloton)	518.9	454.4	257.9	104.4	98.8	1,664.4
⑥Comparison ④/⑤	1.00	1.00	1.00	1.01	1.00	1.00

Source: Authors.

2) LNG tanker operational status

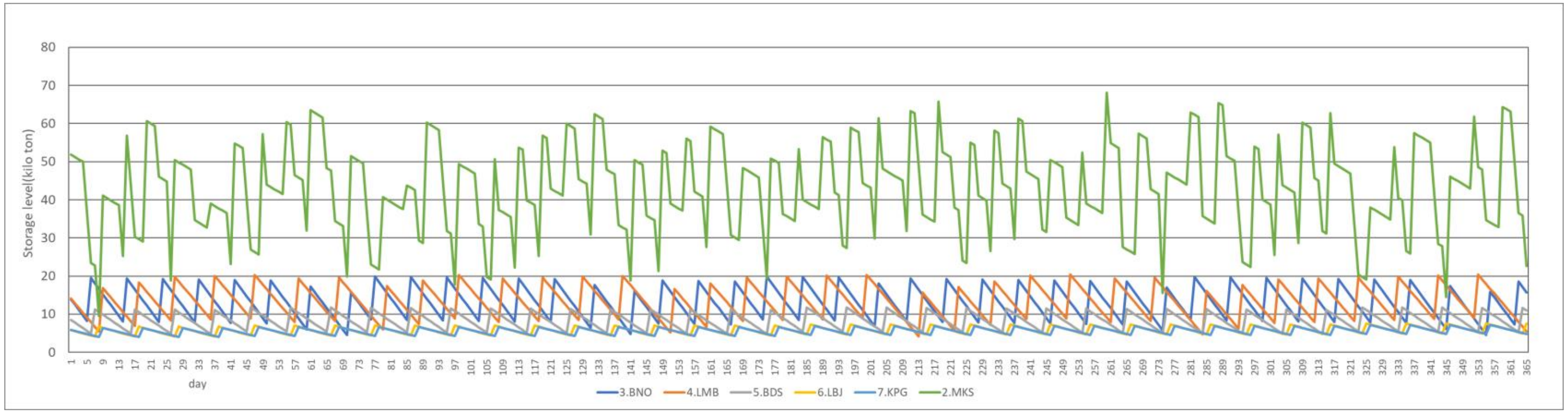
Table 7.43 shows that the operation rates of the two LNG tankers are not significant: 64% for Bali, Lombok and 59% for Badas, Labuan Bajo, and Kupang. In addition, Figure 7.42 indicates no LNG shortage. This is a statistical value regarding the operation of LNG tankers for each route. The waiting time, loading time, transportation time, unloading time, operating time, total time, operating rate, number of times of loading, number of times of unloading are shown.

Table 7.43: Results of Tanker Operations (Secondary Terminal)

Home Port Terminal	Destination	Tanker Number	Waiting Time for Shipment (hour)	Loading Time (hour)	Transport Time (hour)	Unloading Time (hour)	Operating Time (hour)	Total Time (hour)	Rate of Operation	Number of Loading (times)	Number of Unloading (times)
2.MKS	3.BNO 4.LMB	1	3,162	912	3,740	912	5,564	8,726	64%	76	76
	5.BDS 6.LBJ 7.KPG	3	3,512	432	3,328	1,296	5,056	8,568	59%	36	108
Total			**6,673**	**1,344**	**7,068**	**2,208**	**10,620**	**17,294**	**61%**	**112**	**184**
Secondary port transportation											
MSL	2.MKS	9	2,099	612	5,289	612	6,513	8,612	76%	51	51

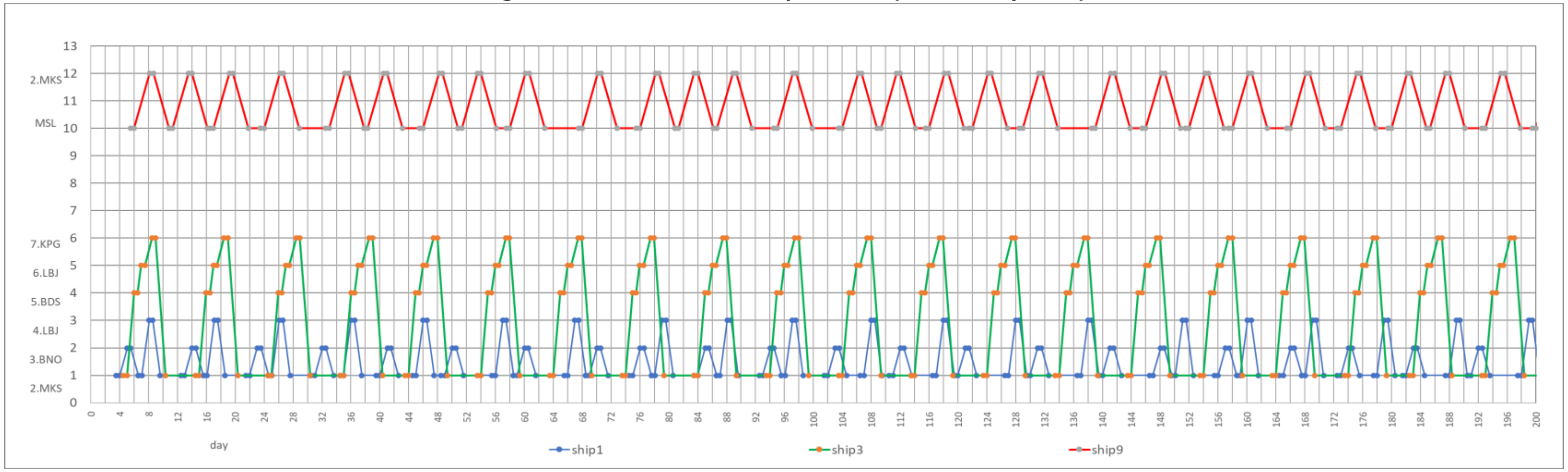
Source: Authors.

Figure 7.42: LNG Storage Level of Each Site (Secondary Port)



Source: Authors' analysis.

Figure 7.43: LNG Tanker Operation (Secondary Port)



Source: Authors' analysis.

3) Key findings

The total operation cost is US$9.70 million, which is much higher than directly delivering LNG from Masela (US$6.94 million). The operation cost from Masela to Makassar of US$6.73 million is high due to the long cruising distance and big volume of loaded LNG. LNG demand in Makassar is 225 kilotons whilst that of five other cities is 1,417 kilotons, so that the share of Makassar is only 14%. Most LNG transported from Masela to Makassar is delivered to the five LNG receiving sites.

Table 7.44: Cruising Distance and OPEX of Tanker (Secondary Terminal)

						Tanker OPEX	
Home Port Terminal	**Destination**	**Tanker Size**	**Cruise Distance (round-trip miles)**	**Unloading Weight (kiloton)**	**Tonne Miles (1,000 tonne miles)**	**Unit Price (US$/1,000 tonne miles)**	**Ship Operating Costs (million US$/year)**
2.MKS	3.BNO 4.LMB	1	—	961	305,738	5.9	1.80
	5.BDS 6.LBJ 7.KPG	3	—	455	198,104	5.9	1.17
Total				**1,417**	**503,842**		**2.97**
Secondary port transportation							
MSL	2.MKS	9	35,445	1,642	1,141,329	5.9	6.73

Source: Authors.

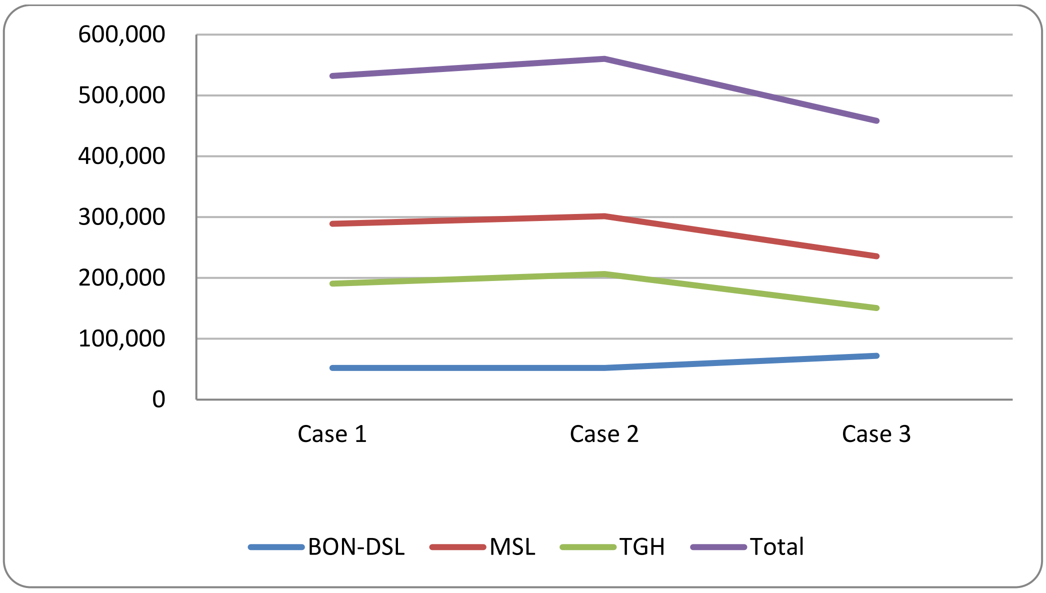
4. Dynamic Simulation Results vs Linear Programming Results

This section compares the DS results with LP results. The unit of LP results is shown by volume x distance, so that the simulation results are also converted to volume x distance. Before that, the cruising distances of cases 1–3 are compared.

4.1. Cruising distance of cases 1–3 (DS)

The cruising distance between cases 1 and 2 are the same or almost the same because the hub & spoke method is applied. But case 3 applies the milk-run method, so that the cruising distance of case 3 is generally shorter than cases 1 and 2, except for the Bontang–Donggi group. For the Masela and Tangguh groups, the milk-run method contributes to the reduction of the number of cruises returning to the LNG production port compared to hub & spoke method. But in the case of the Bontang–Donggi group, the milk-run method reduces returned cruises to Donggi and Bontang, whilst new cruises of Manado–Makassar, Makassar–Bontang, and Palu–Donggi are added. As a result, the cruising distance of case 3 becomes longer than cases 1 and 2 in the Bontang–Donggi group.

Figure 7.44: Cruise Distance, by Case and Group (Round-trip Miles)

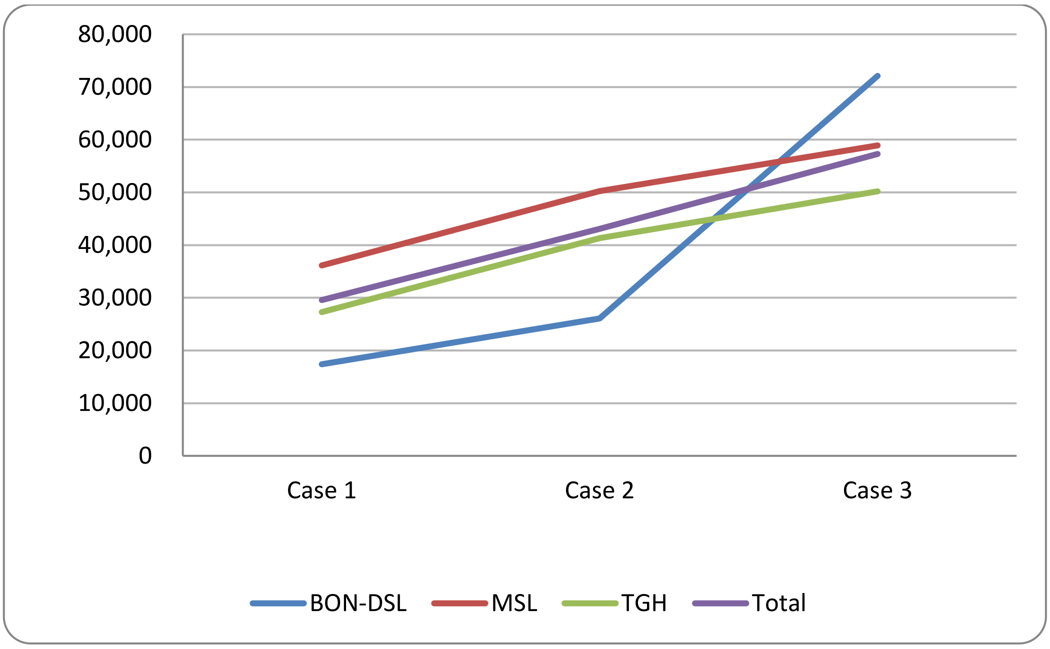


Source: Authors.

4.2. Cruising distance per LNG tanker of the dynamic simulation

Depending on the number of LNG tankers and their operation rates, cruising distance per LNG tanker of case 3 is longest, followed by cases 2 and 1. The Bontang–Donggi group is a small area but, in case 3, only one tanker goes around two LNG production sites and three LNG demand sites. Therefore, case 3 of the Bontang–Donggi group shows a longer cruising distance than Masela and Tangguh.

Figure 7.45: Cruising Distance per Tanker



Source: Authors.

4.3. LP vs DS results based on tonne miles

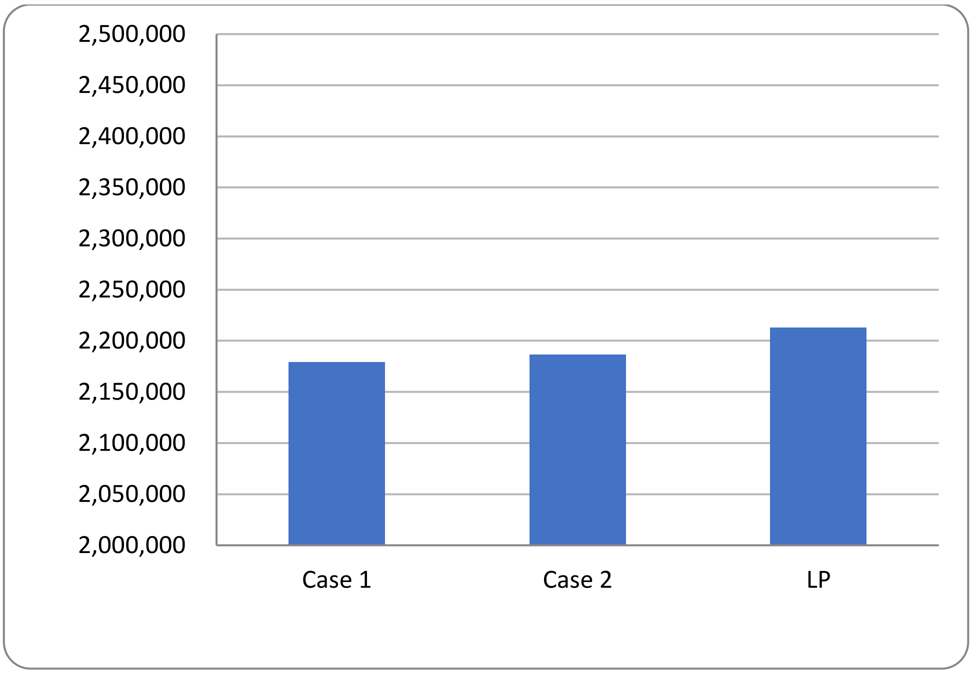
Theoretically, the tonne miles of cases 1 and 2 should be the same as the LP model. But in the DS study, each storage has its initial stock (basically one-half or two-thirds capacity of storage) and this stock is not reflected in tonne miles. In Table 7.45, a ratio defined as DP divided by LP in terms of total tonne miles are close at 0.98. Needless to say, case 3 of the dynamic simulation is much lower than the LP in terms of tonne miles.

Table 7.45: Comparison of Distance of Cases 1–2 and Linear Programming (tonne miles)

Dynamic Simulation		
	Case 1	**Case 2**
BON–DSL	215,851	215,851
MSL	1,475,988	1,486,183
TGH	487,455	484,626
Total	2,179,295	2,186,660
DS/LP	0.985	0.988
LP		
2,213,109		

DS = dynamic simulation, LP = linear programming.
Source: Authors.

Figure 7.46: Comparison of Tonne Miles of Cases 1–2 of Dynamic Simulation and Linear Programming (tonne miles)



Source: Authors.

5. Economic Evaluation based on the Simulation Results

5.1. Estimation of CAPEX and OPEX

a. Bontang–Donggi Senoro group

The estimation results of CAPEX and OPEX of LNG onshore storages and LNG tankers are shown in Table 7.46 based on the cost assumptions specified in Section 7.2 and the simulation results of the Bontang–Donggi group. The CAPEX is converted into annual cost such as depreciation using the construction costs of LNG onshore storages and LNG tankers depending on their sizes, SS–L, and on the duration, which is 20 years. The annual total cost consisting of CAPEX and OPEX is shown in Table 7.47. Due to one LNG tanker's operation, the CAPEX and OPEX of case 3 are much lower than cases 1 and 2. Thus, the milk-run method supported by one LNG tanker is recommended to deliver LNG in the Bontang–Donggi group.

Table 7.46: CAPEX and OPEX of Cases 1–3, BON–DSL

<table>
<tr><td colspan="2" rowspan="4">Onshore Storage</td><td>Abbreviation</td><td>1.PAL</td><td>0.MND</td><td>2.MKS</td><td rowspan="2">Total</td><td rowspan="2">Unit</td></tr>
<tr><td>Size</td><td>M</td><td>M</td><td>M</td></tr>
<tr><td>①CAPEX</td><td>139.5</td><td>139.5</td><td>139.5</td><td>417.0</td><td>Million US$</td></tr>
<tr><td>a. OPEX</td><td>3.5</td><td>3.5</td><td>3.5</td><td>10.5</td><td>Million US$/year</td></tr>
<tr><td rowspan="5">Case 1
Hub & Spoke</td><td rowspan="4">Tanker</td><td>Size</td><td>S</td><td>S</td><td>S</td><td>3</td><td>Tankers</td></tr>
<tr><td>②CAPEX</td><td>48.66</td><td>48.66</td><td>48.66</td><td>145.98</td><td>Million US$</td></tr>
<tr><td>b. OPEX (Management costs)</td><td>4.20</td><td>4.20</td><td>4.20</td><td>12.60</td><td>Million US$/year</td></tr>
<tr><td>c. OPEX (Operating costs)</td><td>0.21</td><td>0.29</td><td>0.77</td><td>1.27</td><td>Million US$/year</td></tr>
<tr><td>Total</td><td>OPEX（b+c）</td><td>4.41</td><td>4.49</td><td>4.97</td><td>13.88</td><td>Million US$/year</td></tr>
<tr><td rowspan="5">Case 2
Multiple Locations</td><td rowspan="4">Tanker</td><td>Size</td><td>S</td><td colspan="2">S</td><td>2</td><td>Tankers</td></tr>
<tr><td>②CAPEX</td><td>48.66</td><td colspan="2">48.66</td><td>97.32</td><td>Million US$</td></tr>
<tr><td>b. OPEX (Management costs)</td><td>4.20</td><td colspan="2">4.20</td><td>8.40</td><td>Million US$/year</td></tr>
<tr><td>c. OPEX (Operating costs)</td><td>0.21</td><td colspan="2">1.06</td><td>1.27</td><td>Million US$/year</td></tr>
<tr><td>Total</td><td>OPEX（b+c）</td><td>4.41</td><td colspan="2">5.26</td><td>9.67</td><td>Million US$/year</td></tr>
<tr><td rowspan="5">Case 3
Milk-Run</td><td rowspan="4">Tanker</td><td>Size</td><td colspan="3">M</td><td>1</td><td>Tankers</td></tr>
<tr><td>②CAPEX</td><td colspan="3">52.50</td><td>52.50</td><td>Million US$</td></tr>
<tr><td>b. OPEX (Management costs)</td><td colspan="3">4.80</td><td>4.80</td><td>Million US$/year</td></tr>
<tr><td>c. OPEX (Operating costs)</td><td colspan="3">1.80</td><td>1.80</td><td>Million US$/year</td></tr>
<tr><td>Total</td><td>OPEX（b+c）</td><td colspan="3">6.60</td><td>6.60</td><td>Million US$/year</td></tr>
</table>

Source: Authors.

Table 7.47: CAPEX and OPEX of LNG Storages and Tankers (Cases 1–3)

BON-DSL Million US$/year

BON-DSL	Case 1	Case 2	Case 3
Storage CAPEX	20.9	20.9	20.9
Storage OPEX	10.5	10.5	10.5
Tanker CAPEX	7.3	4.9	2.6
Tanker OPEX	13.9	9.7	6.6
Total	**52.5**	**45.9**	**40.5**

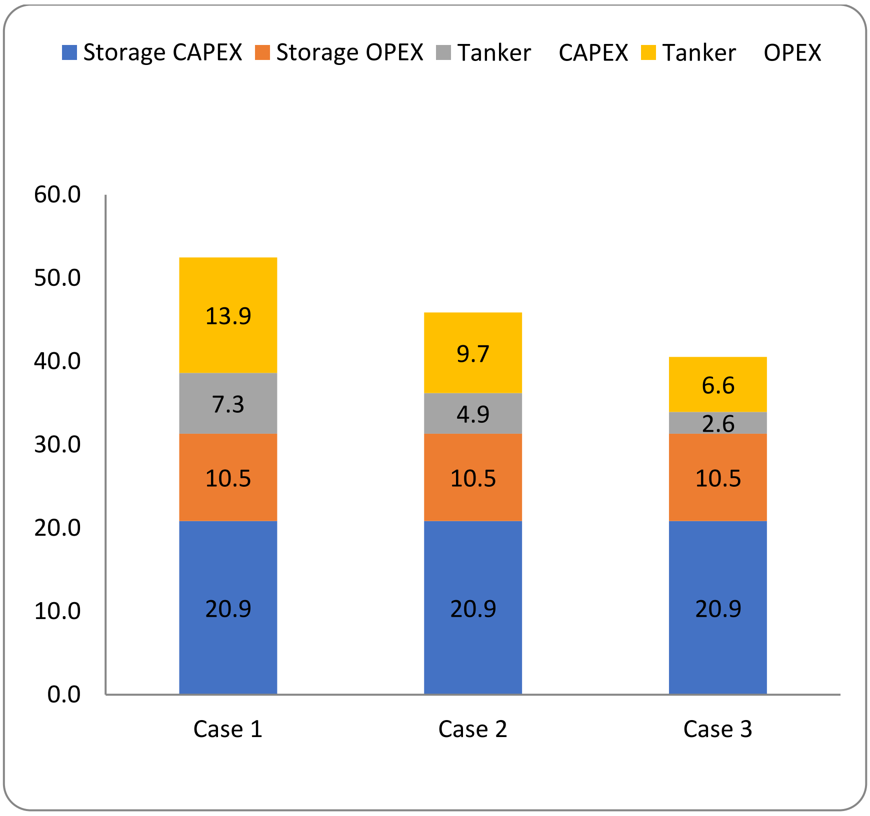
〇〇

Total CAPEX+OPEX (Case 3) Million US$/year

	BON–DSL	MSL	TGH	Total
Storage CAPEX	20.9	48.8	36.9	106.5
Storage OPEX	10.5	24.4	18.4	53.3
Tanker CAPEX	2.6	10.6	6.9	20.2
Tanker OPEX	6.6	28.8	14.3	49.7
Total	**40.5**	**112.6**	**76.5**	**229.7**

Source: Authors.

Figure 7.47: CAPEX and OPEX in LNG Onshore Storages and Tankers, BON–DSL



Source: Authors.

b. Masela group

Table 7.48 shows the estimation results of CAPEX and OPEX of LNG onshore storages and tankers based on the cost assumptions specified in Section 7.2 and the simulation results of the Masela group. Similar to the Bontang–Donggi group, CAPEX is converted into annual cost, such as depreciation, using the construction costs of LNG onshore storages and tankers depending on their sizes, SS to L, and on the duration which is 20 years. The annual total cost of each case consisting of CAPEX and OPEX is shown in Table 7.49. Due to the operation of four LNG tankers, the CAPEX and OPEX of case 3 are much lower than cases 1 and 2. Thus, the milk-run method supported by four LNG tankers is recommended to deliver LNG in the Masela group. Since eight LNG onshore storages and more than four LNG tankers are needed, the total costs of Masela are much higher than the Bontang–Donggi group.

Table 7.48: CAPEX and OPEX, MSL (Cases 1–3)

Onshore Storage		Abbreviation	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	8.AMB	9.NLA	11.TTE	Total	Unit
		Size	L	L	M	S	S	S	S	L		
		①CAPEX	177.2	177.2	139.5	120.6	120.6	120.6	120.6	177.2	975.9	Million US$
		a. OPEX	4.43	4.43	3.49	3.02	3.02	3.02	3.02	4.43	24.41	Million US$/year
Case 1 Hub & Spoke	Tanker	Size	L	M	S	S	S	SS	SS	M	7	Tankers
		②CAPEX	54.8	52.5	48.7	48.7	48.7	36.9	36.9	52.5	324.9	Million US$
		b. OPEX Management costs	5.1	4.8	4.2	4.2	4.2	2.4	2.4	4.8	32.0	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	1.16	0.39	0.25	0.19	0.17	1.63	8.71	Million US$/year
	Total	OPEX (b+c)	7.8	7.0	5.4	4.6	4.5	2.6	2.6	6.4	40.8	Million US$/year
Case 2 Hub & Spoke (Shared use of tankers)	**Tanker**	Size	L	M	S		S	SS		M	5	Tankers
		②CAPEX	54.8	52.5	48.7		48.7	36.9		52.5	262.9	Million US$
		b. OPEX Management costs	5.12	4.78	4.20		4.20	2.38		4.78	25.46	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	1.16		0.70	0.36		1.63	8.77	Million US$/year
	Total	OPEX (b+c)	7.77	7.05	5.36		4.90	2.74		6.41	34.23	Million US$/year
Case 3 Milk-run	**Tanker**	Size	L	M	M			M			4	Tankers
		②CAPEX	54.8	52.5	52.5			52.5			212.4	Million US$
		b. OPEX Management costs	5.12	4.78	4.78			4.78			19.46	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	2.02			2.39			9.33	Million US$/year
	Total	**OPEX (b+c)**	**7.77**	**7.05**	**6.80**			**7.17**			**28.79**	**Million US$/year**

Source: Authors.

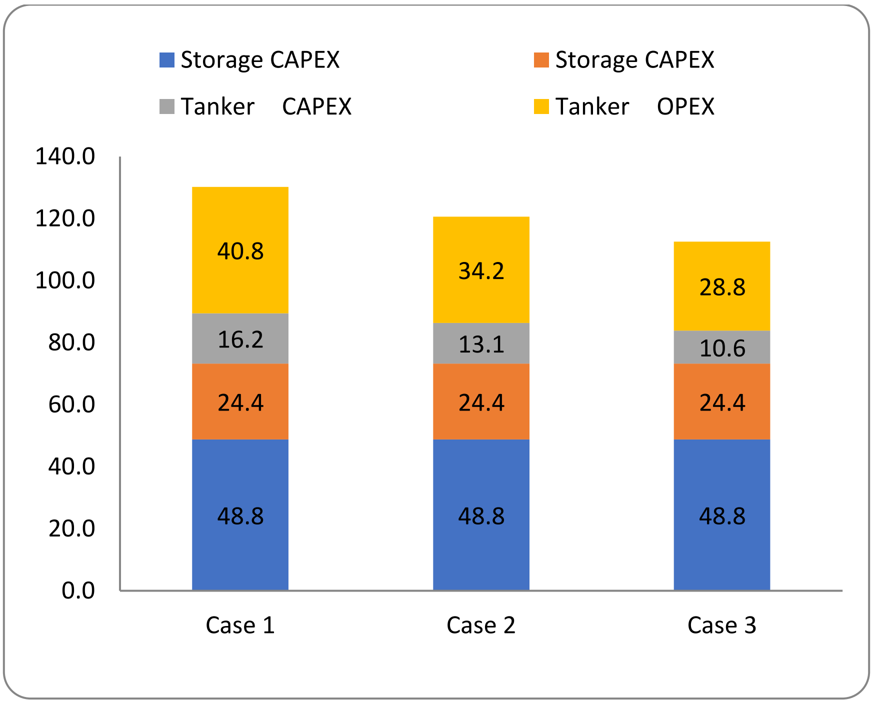
Table 7.49: Comparison of CAPEX and OPEX, MSL (Cases 1–3)

MSL — Million US$/year

MSL	Case 1	Case 2	Case 3
Storage CAPEX	48.8	48.8	48.8
Storage CAPEX	24.4	24.4	24.4
Tanker CAPEX	16.2	13.1	10.6
Tanker OPEX	40.8	34.2	28.8
Total	**130.2**	**120.6**	**112.6**

Source: Authors.

Figure 7.48: Comparison of CAPEX and OPEX, MSL (Cases 1–3)



Source: Authors.

c. Tangguh group

The estimates of CAPEX and OPEX of LNG onshore storages and tankers are shown in Table 7.50 based on the cost assumptions specified in Section 7.2 and the simulation results of the Tangguh group. As in the Masela group, CAPEX is converted into annual cost, such as depreciation, using the construction costs of LNG onshore storages and tankers depending on their sizes, SS to L, and on the duration, which is 20 years. The annual total cost of each case consisting of CAPEX and OPEX is shown in Table 7.51. Due to the operation of three LNG tankers, the CAPEX and OPEX of case 3 are much lower than cases 1 and 2. Thus, the milk-run method supported by three tankers is recommended for LNG delivery in the Tangguh group. Even though seven LNG onshore storages and three LNG tankers are needed, the total costs of Tangguh are much lower than the Masela group. The reasons are shorter cruising distances and smaller LNG delivery amounts than Masela.

Table 7.50: CAPEX and OPEX, TGH, by Case

Onshore Storage		Abbreviation	10.WED	12.SRU	13.BIK	14.MNK	15.SON	17.JAP	16.MRK	Total	Unit
		Size	L	SS	SS	S	M	SS	SS		
		①CAPEX	177.2	75.0	75.0	120.6	139.5	75.0	75.0	737.3	Million US$
		a. OPEX	4.4	1.9	1.9	3.0	3.5	1.9	1.9	18.4	Million US$/year
Case 1	Tanker	Size	S	SS	SS	S	S	SS	SS	7	Tankers
Hub & Spoke		②CAPEX	48.7	36.9	36.9	48.7	48.7	36.9	36.9	297.6	Million US$
		b. OPEX Management costs	4.2	2.4	2.4	4.2	4.2	2.4	2.4	22.1	Million US$/year
		c. OPEX （operating costs ）	1.16	0.09	0.15	0.55	0.56	0.13	0.23	2.88	Million US$/year
	Total	OPEX (b+c)	5.4	2.5	2.5	4.7	4.8	2.5	2.6	25.0	Million US$/year
Case 2	Tanker	Size	S	SS		S		SS	SS	5	Tankers
Hub & Spoke (Shared use of tankers)		②CAPEX	48.7	36.9		52.5		36.9	36.9	212.0	Million US$
		b. OPEX Management costs	4.2	2.4		4.2		2.4	2.4	15.6	Million US$/year
		c. OPEX (operating costs)	1.16	0.24		1.10		0.13	0.23	2.86	Million US$/year
	Total	OPEX (b+c)	5.4	2.6		5.3		2.5	2.6	18.4	Million US$/year
Case 3	Tanker	Size	S	M					SS	3	Tankers
Milk-run		②CAPEX	48.7	52.5					36.9	138.1	Million US$
		b. OPEX Management costs	4.2	4.8					2.4	11.4	Million US$/year
		c. OPEX (operating costs)	1.16	1.55					0.23	2.94	Million US$/year
	Total	**OPEX (b+c)**	**5.4**	**6.4**					**2.6**	**14.3**	**Million US$/year**

Source: Authors.

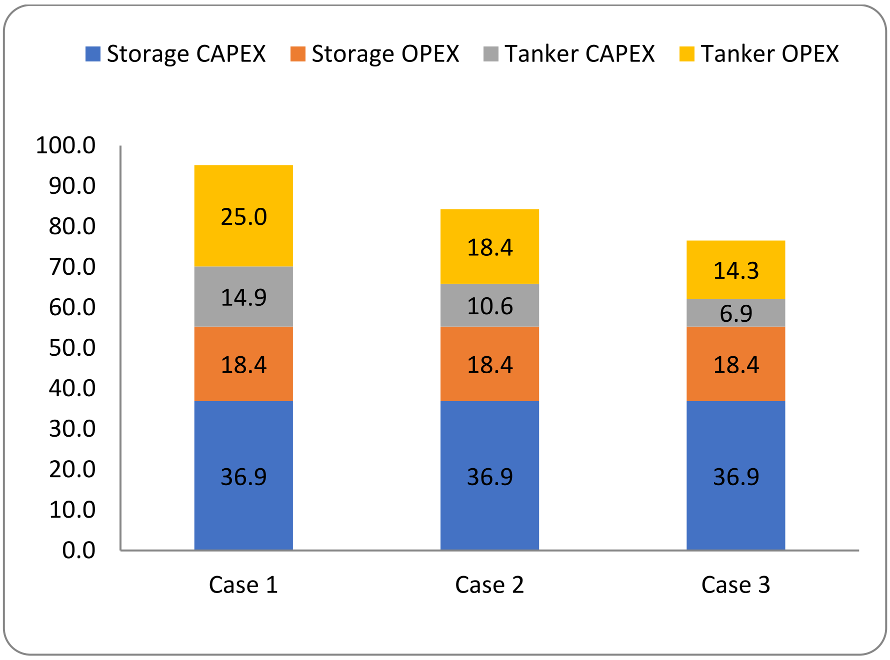
Table 7.51: Comparison of CAPEX and OPEX, TGH (Cases 1–3)

TGH | Million US$/year

	Case 1	Case 2	Case 3
Storage CAPEX	36.9	36.9	36.9
Storage OPEX	18.4	18.4	18.4
Tanker CAPEX	14.9	10.6	6.9
Tanker OPEX	25.0	18.4	14.3
Total	**95.2**	**84.3**	**76.5**

Source: Authors.

Figure 7.49: Comparison of CAPEX and OPEX, TGH (Cases 1–3)



Source: Authors.

d. Application of a secondary terminal between Masela and five destinations

1) CAPEX and OPEX estimates with a secondary terminal

One more simulation applies a secondary terminal at Makassar and five LNG receiving islands, which are Bali, Lombok, Sumbawa, Flores, and Kupang. Estimates of CAPEX and OPEX of LNG onshore storages and tankers are shown in Table 7.52 based on the cost assumptions specified in Section 7.2 and the simulation results of the secondary terminal scenario.

As the Tangguh group, CAPEX is converted into annual cost, such as depreciation, using the construction costs of LNG onshore storages and tankers depending on their sizes, SS to L, and on the duration, which is 20 years. The annual total cost of this scenario consisting of CAPEX and OPEX is shown in Table 7.54. Due to the large LNG onshore storage and tanker operation, the total cost of this scenario is much higher than case 3 of the Masela group.

Table 7.52: CAPEX and OPEX for Application of Secondary LNG Terminal

Secondary Port

			3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	Total	Unit
Onshore Storage		**Abbreviation**	**3.BNO**	**4.LMB**	**5.BDS**	**6.LBJ**	**7.KPG**	**Total**	**Unit**
		Size	**L**	**L**	**M**	**S**	**S**		
		①CAPEX	177.2	177.2	139.5	120.6	120.6	735.2	Million US$
		a.OPEX	4.43	4.43	3.49	3.02	3.02	18.38	Million US$/year
Multiple locations Milk-run	Tanker	Size	M		M			2	Tankers
		②CAPEX	52.5		52.5			105.0	Million US$
		b.OPEX Management costs	4.78		4.80			9.58	Million US$/year
		c.OPEX（operating costs）	1.80		1.17			2.97	Million US$/year
	Total	**OPEX（b+c)**	**6.58**		**5.97**			**12.55**	**Million US$/year**

Secondary port	
2.MKS	Unit
LL	
366.0	Million US$
9.150	Million US$/year
LL 1	Tanker
81.10	Million US$
9.30	Million US$/year
6.73	Million US$/year
16.03	Million US$/year

Source: Authors.

Table 7.53: CAPEX and OPEX for Direct Delivery from MSL to the Five LNG Receiving Sites

3.BNO~7.KPG		Abbreviation	3.BNO	4.LMB	5.BDS	6.LBJ	7.KPG	Total	Unit
Onshore Storage		Size	L	L	M	S	S		
		①CAPEX	177.2	177.2	139.5	120.6	120.6	735.2	Million US$
		a. OPEX	4.43	4.43	3.49	3.02	3.02	18.4	Million US$/year
Case 1	Tanker	Size	L	M	S	S	S	5	Tankers
Hub & Spoke		②CAPEX	54.8	52.5	48.7	48.7	48.7	253.3	Million US$
		b. OPEX Management costs	5.1	4.8	4.2	4.2	4.2	22.5	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	1.16	0.39	0.25	6.7	Million US$/year
	Total	OPEX (b+c)	7.8	7.0	5.4	4.6	4.5	29.2	Million US$/year
Case 2	Tanker	Size	L	M	S		S	4	Tankers
Hub & Spoke (Shared use of tankers)		②CAPEX	54.8	52.5	48.7		48.7	204.7	Million US$
		b. OPEX management costs	5.12	4.78	4.20		4.20	18.3	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	1.16		0.70	6.8	Million US$/year
	Total	OPEX (b+c)	7.77	7.05	5.36		4.90	25.1	Million US$/year
Case 3	Tanker	Size	L	M	M			3	Tankers
Milk-run		②CAPEX	54.8	52.5	52.5			159.8	Million US$
		b. OPEX management costs	5.12	4.78	4.78			14.7	Million US$/year
		c. OPEX (operating costs)	2.65	2.27	2.02			6.9	Million US$/year
	Total	**OPEX (b+c)**	**7.77**	**7.05**	**6.80**			**21.6**	**Million US$/year**

Source: Authors.

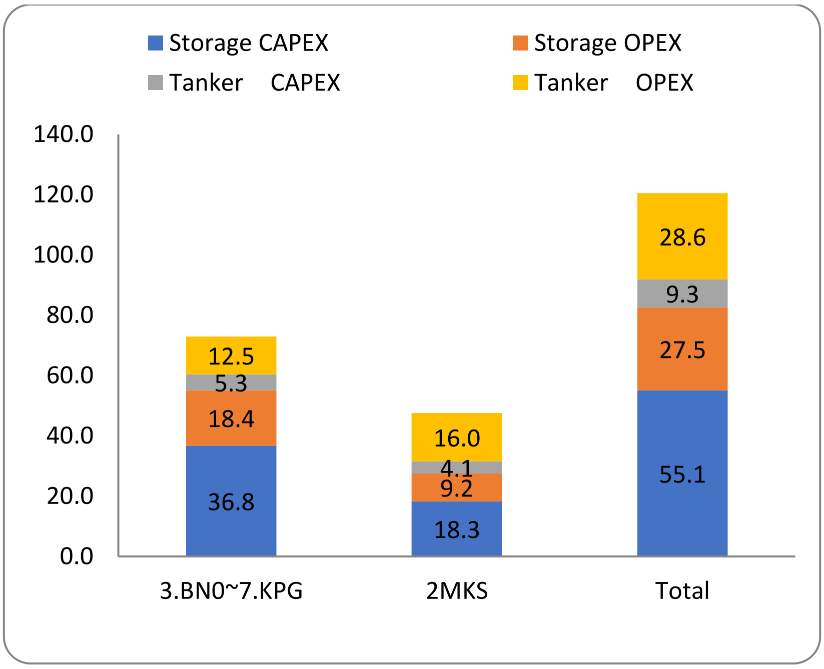
Table 7.54: Total CAPEX and OPEX for Application of Secondary LNG Terminal

Secondary port Million US$/year

	3.BN0~7.KPG	2MKS	Total
Storage CAPEX	36.8	18.3	55.1
Storage OPEX	18.4	9.2	27.5
Tanker CAPEX	5.3	4.1	9.3
Tanker OPEX	12.5	16.0	28.6
Total	**72.9**	**47.5**	**120.5**

Source: Authors.

Figure 7.50: Total CAPEX and OPEX for Application of Secondary LNG Terminal



Source: Authors.

e. Cost comparison between direct delivery of LNG and via a secondary terminal

Table 7.55 compares the cost between direct LNG delivery from Masela to the five LNG receiving sites and via the secondary terminal at Makassar. The left-hand table shows the CAPEX and OPEX of LNG storages and tankers under the secondary terminal scenario, which is the same as Table 7.54. On the other hand, the right-hand table shows the CAPEX and OPEX of LNG storages and tankers of direct LNG deliveries from Masela. ③ indicates the CAPEX and OPEX at Makassar, which is case 1 of Table 7.46. ④ means the CAPEX and OPEX of case 3 of Table 7.48. As a result, the total cost of applying the secondary terminal is US$18 million higher than the direct LNG delivery from Masela. The reason is a significant CAPEX of super L-sized LNG storage at Makassar and L-sized LNG tanker to cruise between Masela and Makassar.

Table 7.55: Cost Comparison between Direct Delivery of LNG and Via a Secondary Terminal

Million US$/year

Secondary port (Delivery from secondary port)				Directly from base		Million US$/year
	① **3.BN0~7.KPG**	② **2.MKS**	**Total**	③ 2.MKS	④ 3.BNO~7.KPG	Newly increasing investment ①＋②－③－④
Storage CAPEX	36.8	18.3	55.1	7.0	36.8	11.3
Storage OPEX	18.4	9.2	27.5	3.5	18.4	5.7
Tanker CAPEX	5.3	4.1	9.3	2.4	8.0	-1.1
Tanker OPEX	12.5	16.0	28.6	5.0	21.6	2.0
Total	**72.9**	**47.5**	**120.5**	17.9	84.8	17.9
	Newly increasing costs			Cost of disappearing		

Source: Authors.

f. Comparison of CAPEX in each group

1) CAPEX

Table 7.56 summarises CAPEX of LNG onshore storages and tankers of case 3 (lowest cost amongst cases 1–3) in each group. A US$2,533 million–worth of investment will be needed to facilitate the LNG delivery chain in Eastern Indonesia and more than 80% of the investment will go to the construction of LNG onshore storages.

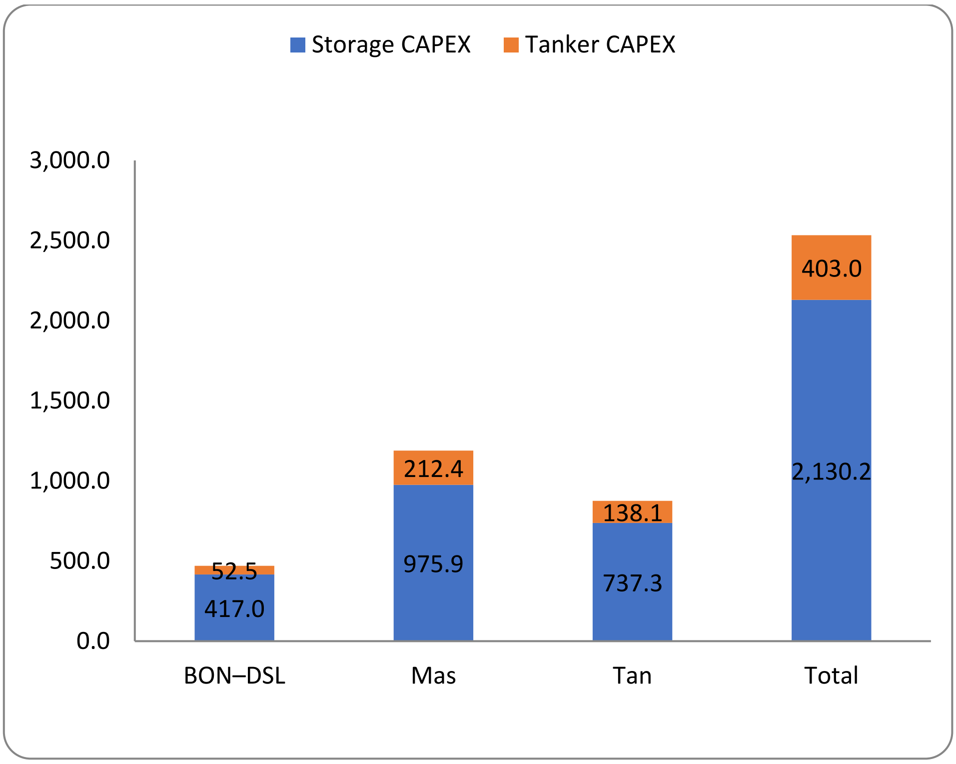
Table 7.56: CAPEX of Each Group (Case 3)

Total CAPEX (Case 3) Million US$

	BON–DSL	Mas	Tan	Total
Storage CAPEX	417.0	975.9	737.3	2,130.2
Tanker CAPEX	52.5	212.4	138.1	403.0
Total	**469.5**	**1,188.3**	**875.4**	**2,533.2**

Source: Authors.

Figure 7.51: CAPEX of Each Group (Case 3)



Source: Authors.

How about CAPEX of cases 1 and 2? Table 7.57 clearly shows that CAPEX of case 3 is the lowest amongst cases 1–3. This is because CAPEX of LNG storages amongst the cases shows no change. However, CAPEX of LNG tankers depends on the number of LNG tankers.

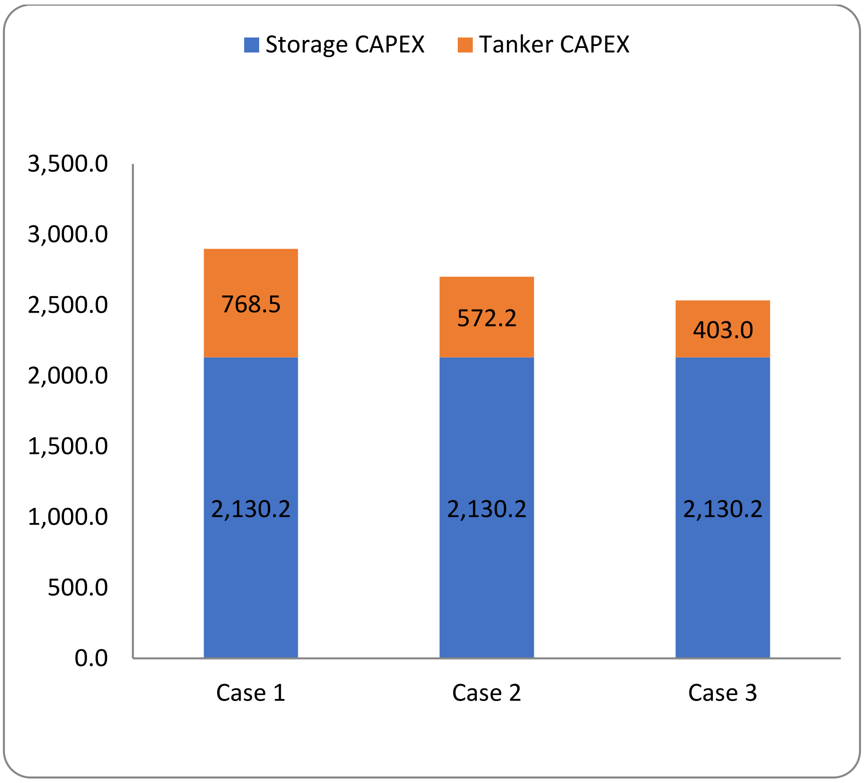
Table 7.57: Total CAPEX of Each Case

Total CAPEX — Million US$

	Case 1	Case 2	Case 3
Storage CAPEX	2,130.2	2,130.2	2,130.2
Tanker CAPEX	768.5	572.2	403.0
Total	**2,898.7**	**2,702.4**	**2,533.2**

Source: Authors.

Figure 7.52 Total CAPEX, by Group (Cases 1–3)



Source: Authors.

2) Annual expenses

Comparing the total cost of each group, Table 7.58 summarises the total costs (CAPEX + OPEX) of LNG onshore storages and tankers of case 3 (which has the lowest cost amongst cases 1–3 [refer to Table 7.59 and Figure 7.54]) per each group. CAPEX is converted into annual basis. A total of US$229.7 million per year of total operation costs will be needed to facilitate the LNG delivery chain in Eastern Indonesia. Using the LNG delivery amounts per each group – 669 kilotons for Bontang–Donggi; 2,047 kilotons for Masela; and 988 kilotons for Tangguh – the unit costs of LNG are calculated at US$60/tonne, US$55/tonne, and US$77/tonne, respectively. These costs do not include LNG production costs. Thus, the unit costs are high compared to Japan's LNG CIF (cost, insurance, and freight), which was US$50–US$70/tonne in the last 2 years.

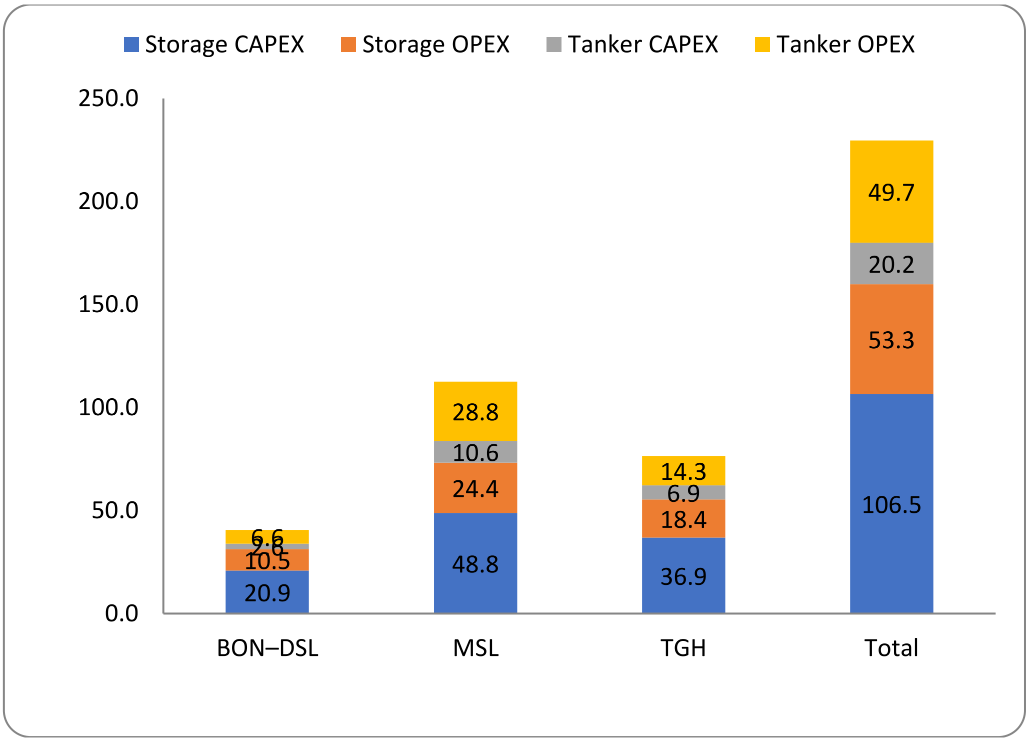
Table 7.58: CAPEX and OPEX of Each Group (Case 3)

Total CAPEX+OPEX (Case 3) Million US$/year

	BON–DSL	MSL	TGH	Total
Storage CAPEX	20.9	48.8	36.9	106.5
Storage OPEX	10.5	24.4	18.4	53.3
Tanker CAPEX	2.6	10.6	6.9	20.2
Tanker OPEX	6.6	28.8	14.3	49.7
Total	**40.5**	**112.6**	**76.5**	**229.7**

Source: Authors.

Figure 7.53: CAPEX and OPEX, by Group (Case 3)



Source: Authors.

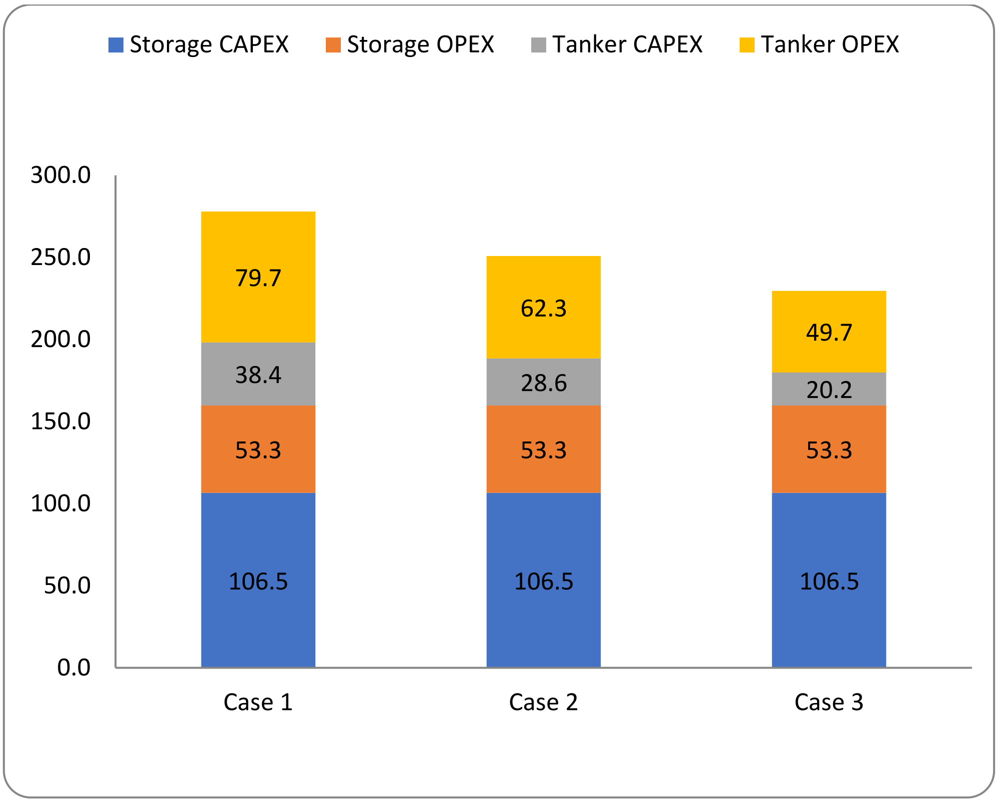
Table 7.59: CAPEX and OPEX (Cases 1–3)

Total CAPEX+OPEX Million US$/year

	Case 1	Case 2	Case 3
Storage CAPEX	106.5	106.5	106.5
Storage OPEX	53.3	53.3	53.3
Tanker CAPEX	38.4	28.6	20.2
Tanker OPEX	79.7	62.3	49.7
Total	**277.9**	**250.8**	**229.7**

Source: Authors.

Figure 7.54: CAPEX and OPEX (Cases 1–3)



Source: Authors.

5.2. Summary of DS results

Since Eastern Indonesia (surrounded by Kalimantan, Sulawesi, Papua, and Nusa Tenggara islands) covers a wide area, this study applied the LP model (optimisation approach) to seek basic LNG delivery routes from four LNG production sites (Bontang, Donggi, Masela, and Tangguh) to 18 LNG demand sites. The LP model extracts three LNG delivery groups: (i) the Bontang–Donggi group to cover three cities in the north-west; (ii) Masela group to cover eight cities in the south and north-central part; (iii) Tangguh group to cover seven cities in the east.

DS was applied to seek for the appropriate capacity of onshore storages at each LNG demand site and the number of LNG tankers and tanker size through three case studies. Case 1 assigns one tanker to one LNG demand site with hub & spoke as the delivery method. Thus, case 1 needs the same number of LNG tankers as the number of LNG demand sites. Case 2 reduces the number of LNG tankers, assuming that one ship covers two LNG demand cities; thus, case 2 shows a higher operation rate of LNG tankers than case 1. Case 2 applies the hub & spoke method. Case 3, which applies the milk-run method, also reduces the number of LNG tankers from case 2. Due to appropriate setting of assumed parameters which are capacity, initial volume and calling time of an LNG tanker of the LNG onshore storages, and capacity of LNG tankers, all three cases in the three groups are feasible.

Basically, the capacity of onshore storage per each demand site is assumed to be appropriate considering the annual LNG demand volume of and the distance between the cities and an LNG production site. Cases 2 and 3 indicate efficient use of the LNG onshore storages because the ratios defined as maximum level capacity are more than 0.6, except for Weda (0.45). If the number of LNG tankers are reduced, the maximum level of the storages has to be higher than case 1 because the transport of LNG takes time compared to case 1.

The necessary number of LNG tankers depends on the size of LNG onshore storages and LNG delivery methods, which are hub & spoke and milk-run. The number of LNG tankers of all cases shown in this report is feasible. Looking at the economic analysis results, case 3 is recommended due to its lowest cost. But case 3 applies the milk-run method whose operation is complicated; an emergency disruption might affect normal operations. Thus, a contingency plan is also recommended if the milk-run method will be applied.

5.3. Policy Implications

a. Issues and challenges

The dynamic simulations are successful under appropriate assumptions such as several parameters of LNG onshore storages at the demand sites and LNG tankers in the groups. As a result, the simulation study contributes to extracting the appropriate size of LNG onshore storage per each demand site and the size and operation method of LNG tankers per each group. But the simulation study does not consider natural disasters, accidents, and preventive maintenance. Therefore, more thorough simulation studies to include the negative conditions mentioned earlier will be needed. One more issue is that smaller LNG tankers are main vessels due to the shallow water depth of ports at the LNG demand sites. But if the simulation assumes the construction of dolphin structures between a pier on land and a berth at a deeper place in the water, the simulation can use large LNG tankers to engage the milk-run method.

b. Secondary terminal scenario

Application of a secondary LNG storage between LNG production sites and LNG demand sites is expected. This is to reduce LNG delivery costs due to shorter distance from the secondary terminal to the demand sites and have economic advantage to achieve bulk LNG transport using a large LNG tanker from LNG production site to the secondary terminal. But the results of the simulation studies do not recommend this scenario due to significant costs of the secondary terminal.

c. Milk-run method

The milk-run method contributes to reducing the number of LNG tankers. Therefore, the total operation cost of the LNG tankers become lower than the hub & spoke method due to the lower CAPEX of the LNG tankers. Thus, appropriate assumptions of LNG storages, such as initial volume and scheduling of the LNG tankers, are extremely important in case the milk-run method is applied.

d. Power development policy

As mentioned before, the LNG delivery cost in Eastern Indonesia, which consists of four LNG production sites and 18 LNG demand sites, is too high according to the simulation study. It will be US$55–US$77 per tonne without LNG production cost. One reason is that LNG demand at more than half of the 18 demand sites is not significant due to smaller electricity demand. Thus, gas power generation can be applied for higher electricity demand sites such as Bali, Lombok, Halmahera, and Ternate. Other power generation systems such as the hybrid system of diesel and solar PV with microgrid can be applied in small and midsized electricity demand sites.

Chapter 8

Conclusions and Recommendations

This project used the linear programming (LP) and dynamic simulation (DS) approaches. The LP approach is one of the optimisation methods and, under several constraints, it seeks to minimise costs or maximise profits. In this project, the LP approach, considered as the optimal transport model, was used to find the minimum cost of LNG flows from origin (LNG production sites) to destination (LNG demand sites) based on distances between them. There are two constraints: supply and demand. On the other hand, the DS approach fully depends on the queuing theory of operations research. Usually, the queuing theory applies to seek, for example, the necessary number of elevators when a new office building is constructed based on the number of workers at and visitors to the office building. A PC-based DS software generates transactions at random. In the case of a new office building mentioned above, the transactions are the number of workers and visitors to arrive in front of the elevators every second or minute during rush hours, such as 8–9 a.m. and 5–6 p.m. The status of the queues in front of the elevators are checked. In this case, the number of elevators is a parameter and, based on trial and error, we seek for the appropriate number of elevators by assessing the length of the queues. In this project, the parameters were necessary capacity, initial amount of LNG before starting the simulation, storage level to call an LNG tanker at 18 cities and areas in Eastern Indonesia. For LNG tankers, we sought for their necessary number and size to deliver LNG from the production sites to the demand sites. We also assessed two LNG delivery methods, hub & spoke and milk-run under the DS approach. By implementing multiple simulations to tune up the parameters, the results of nine cases (three cases x three groups) plus one were eventually extracted.

MEMR Indonesia plans to shift from the current diesel power plants system to the gas-fired power plant (GPP) system in Eastern Indonesia, roughly defined as the area surrounded by Kalimantan, Sulawesi, Papua, and Nusa Tenggara islands. One reason is that four LNG production sites in this area are currently exporting LNG to Japan. Another reason is the remarkable electricity demand potential in this area. However, the electricity demand will be extremely diverse – from 16,799 GWh at Makassar to 116 GWh at Serui, Yapen Island in 2030. On the other hand, GPPs consuming LNG need an ISO (International Standard Organization) tank or storage to stock LNG. Storage is very expensive because CAPEX plus OPEX of ISO tanks account for 70% of the total cost of LNG delivery to 18 cities and areas in this area, according to the simulation results. Thus, this report suggests that the following cities and areas shift to GPP by 2030 due to their large LNG demands:

1) Bali, Lombok and Sumbawa in Nusa Tenggara Island
2) South Halmahera, Ternate, Sorong city, and Manokwari in Maluku and Papua
3) Palu, Makassar, and Manado in Sulawesi

Other cities and areas, such as Jayapura city, Labuan Bajo, Kupang, etc., need to seek for other power systems, such as a hybrid power system integrating a diesel power plant and solar/PV with microgrid system, to decrease their power generation costs.

This area has four LNG production sites: Bontang, Donggi Senoro, Masela, and Tangguh. LNG production at Bontang LNG will decrease after 2026 and will be less than 3 MTPA in 2030. Donggi Senoro LNG will increase its LNG production by about 2 MTPA and all will be exported to Japan and the Republic of Korea. Masela LNG will start LNG production in 2020 and will increase it to 9 MTPA eventually after finding its LNG buyers. Tangguh LNG will decrease its LNG production from 2029 which will be less than 10 MTPA in 2030. On the other hand, GPPs will be constructed in Sulawesi (north, central, and south), West Nusa Tenggara Islands such as Bali and Lombok, and Weda and Ternate in northern Maluku. Regarding distance to these high LNG-demand places, Bontang LNG and Donggi Senoro LNG are in better positions to deliver to these places. Thus, this report recommends that Bontang and Donggi Senoro dedicate LNG delivery to domestic users whilst Masela and Tangguh mainly engage in LNG export to minimise shipping costs of LNG to domestic users in Eastern Indonesia.

This project extracts a wealth of meaningful information regarding LNG delivery to GPPs in Eastern Indonesia. The milk-run method is much better than the hub & spoke method in this area. Since LNG demand sites are close to each other, the milk-run method can reduce total cruising distance of LNG tankers and decrease the number of LNG tankers by making an LNG tanker cover a few LNG demand sites. The LNG delivery cost consists mainly of LNG storages and tankers. The cost share of LNG storages is around 70% and CAPEX of LNG storages is about 50%. Thus, the construction cost of LNG storages is crucial due to the necessity for an ISO tank. However, the operation rate of some LNG tankers is still less than 50% and the capacity of some LNG storages seems to be oversized. These non-realistic assumptions should be improved. Thus, more precise DS studies will be needed to obtain more realistic simulation solutions based on more accurate parameters, such as capacity, initial amount of LNG at LNG storages, appropriate LNG level to call an LNG tanker, as well as CAPEX and OPEX of LNG storages and tankers.

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