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Assessment of Readiness for Fossil Fuel Import Disruption

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Contents

List of Figures

List of Tables

List of Abbreviations

ASEAN	Association of Southeast Asian Nations
bcm	billion cubic metres
BPK	Bang Pakong power plant
BTU	British thermal unit
BV#22, #26	Block Valve #22, #26
BVW#1, #10	Block Valve West #1, #10
C_2+	ethane or higher molecular weight components
EAS	East Asia Summit
EGAT	Electricity Generating Authority of Thailand
EPEC	Eastern Power and Electric power plant
EPPO	Energy Policy and Planning Office, Thailand
GLW	Glow IPP power plant
GNS	Gulf JP Nong Saeng district power plant
GPG	Gulf Power Generation power plant
GPSC	Global Power Synergy power plant
GSP	gas separation plant
GUT	Gulf JP Uthai district power plant
GWh	gigawatt hour
IEEJ	Institute of Energy Economics, Japan
IPP	independent power producer
JDA	Joint Development Area (Malaysia-Thailand)
kboed	thousand barrels of crude oil equivalent/day
kg	kilogram
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m^3	cubic metre
MEA	Metropolitan Electricity Authority
MJ	megajoule
mmbtu	million British thermal units
MMSCFD	million standard cubic feet per day
mmtpa	million metric tonnes per annum
MTJDA	Malaysia-Thailand Joint Development Area
MTP	Map Ta Phut
MVA	megavolt ampere
MW	megawatt
NBK	North Bangkok power plant
NG	natural gas
NGD	natural gas distribution company
NGL	natural gas liquids
NGR	natural gas distribution
NGV	natural gas for vehicles
OCS #1,2,3	Onshore Compressor Station #1, 2, 3
PEA	Provincial Electricity Authority, Thailand

PL	pipeline
PPA	power purchase agreement
PTIT	Petroleum Institute of Thailand
PTT	Petroleum Authority of Thailand, PTT Public Company Limited
RA#6	Ratchaburi-Wangnoi #6 Block Valve Station
RE	renewable energy
RGCO	Ratchaburi Electricity Generating Co, Ltd power plant
RGTE	Ratchaburi Tri Energy Co, Ltd power plant
RPCL	Ratchaburi Power Co, Ltd power plant
SBK	South Bangkok power plant
scf	standard cubic foot
SPP	small power producer
TTM	Trans Thailand–Malaysia Gas Pipeline
TSO	transmission system operator
TWh	terawatt-hour
VSPP	very small power producer
WI	Wobbe Index
WN	Wang Noi power plant
yr	year
2C	contingent proved plus probable resources
2P	proved plus probable reserves
3P	proved plus probable plus possible reserves

Executive Summary

Many emerging countries in the East Asia Summit (EAS) region are likely to increase dependence on imported fossil fuel supply in the future. This trend means that the energy security of these countries will become more vulnerable. Thus, it will be vital for them to do the following:

(i) understand the influence and impact of unexpected import disruptions,

(ii) understand how a country can react, and

(iii) implement necessary policy actions to enhance energy security.

Among various fossil fuels, liquefied natural gas (LNG) is considered an increasingly important energy supply source in the coming decades. This study looks at disruption of LNG imports to investigate possible countermeasures and contingency plans.

The study compares the energy status in emerging EAS countries introducing LNG, such as Myanmar, the Philippines, Thailand, and Viet Nam. Among these countries, Thailand is chosen as the most suitable candidate for a case study for a number of reasons, such as its reasonably diversified natural gas supply sources, including indigenous natural gas resources and import of natural gas from Myanmar via pipelines. Furthermore, Thailand plays a leading role in LNG imports in the region.

The risk assessment process for analysing LNG import disruptions is discussed. This study applies the 'N-1 formula', which has been widely used to assess gas supply security in the European Union. Having identified risk sources of LNG disruption and their amounts and durations, the study has compiled a set of LNG import disruption scenarios. These include import disruption of the largest long-term contract and total failure of the largest LNG receiving terminal as the two most serious disruption possibilities. They also cover unprecedented worst-case scenarios that necessitate action from the government as a matter of national energy security.

The study investigates in-depth possible countermeasures for LNG import disruptions. For Thailand, comprehensive results demonstrate that in the short term the country is reasonably resilient against LNG import disruptions, although consideration should be given to long-term energy security, especially as Thailand is expected to rely on more LNG imports in the future.

The report concludes with some policy recommendations. The risk assessment process of LNG import disruptions and countermeasures are generalised and summarised for countries to potentially incorporate into national energy supply plans. In addition, recommendations for energy policy, LNG import and natural gas policy, and regional cooperation are discussed. It is stressed that countries need to set up long-term energy supply plans, which should be considered along with building resilience against LNG import disruptions..

Chapter 1

Background and Objective

Many emerging countries in the East Asia Summit (EAS) region are likely to increase dependence on fossil fuel imports in the future. This trend means an increase in countries' energy security vulnerability. It is imperative for such countries to do the following:

(i) understand the influence and impact of unexpected import disruptions,

(ii) understand how a country can react, and

(iii) implement necessary policy actions to enhance energy security.

Each country in the EAS region has a unique energy supply portfolio consisting of a variety of energy sources such as coal, oil, natural gas, and renewables. Some countries have indigenous energy sources and their degree of diversification in energy supply sources varies. What almost all EAS countries have in common, however, is that they are very likely to rely on more fuel imports to grow their economies. Therefore, more attention should be given to resilience against the disruption of fuel imports. Such disruptions are not an uncommon occurrence and happen for a variety of reasons –political, economic, technical, and environmental.

Among various fossil fuels, liquefied natural gas (LNG) has been chosen for this study for a number of reasons, which are mentioned below. Although LNG is expected to play a bigger role in the future energy mix, since it is somewhat new among Member States of the Association of Southeast Asian Nations (ASEAN), there has been little attention on its supply security in terms of study or tangible actions. Oil and coal, on the other hand, given that they are more conventional and popular fuels in the region, enjoy the benefit of a mature global market, a redundant domestic supply system, and stockpile. Assessing resilience against the disruption of LNG imports may provide crucial insights for the energy security of many emerging EAS countries in the coming future.

1.1. Increasing demand and import dependence

LNG is considered an increasingly important energy supply source in the coming decades, both for resource reserve and environmental reasons. However, natural gas production is not keeping pace with the increased demand in many ASEAN Member States, which have just started or will soon start importing LNG. Even Indonesia and Malaysia, major LNG exporting countries in the EAS region, will soon rely on LNG imports to support their own economic growth. This gives rise to new concerns over national energy supply security.

Meanwhile, even though the import dependence of oil is higher than that of natural gas, because of the inherent supply security risk of oil, better countermeasures have been implemented. For coal, in general, import dependence – and thus supply security risk – is well below that of oil and natural gas due to the abundance of the resource in the region.

1.2. Exporting countries

While LNG exporting countries are widely believed to be diversified, Qatar, a country located inside the Strait of Hormuz, dominates global LNG production/export its share nearing one third in recent years. Recent conflicts between Qatar and its neighbours have highlighted the significance of LNG from Qatar – and the resulting need for further diversification.

Even the largest oil producers, Saudi Arabia and the Russian Federation, have a share of only around 13% of the world's production, respectively. Together with the tight oil production and exports from the United States, oil exporting countries are more diversified than LNG exporting countries. Coal exporting countries are rather concentrated, but their significance is that most trading partners are within the same EAS region (Australia, China, Indonesia, and the Russian Federation), whereas supply is free from geopolitical problems in the Middle East and choke-point risks in the Strait of Hormuz.

1.3. Flexibility of supply

Unlike crude oil and coal, which have mature global markets, the LNG market is rather new and still lacks the flexibility of redundant export and import capacity. Most of the transactions are still made under traditional long-term oil-price-linked contracts. Therefore, flexible spot transactions that can fill the supply–demand gap in emergency situations are limited compared to oil and coal.

Similarly, oil and coal are generally traded under short-term (less than 1-year) contracts or on a spot basis. Therefore, they have more supply flexibility. This flexible global market provides short-term supply security for market participants – that is, anyone can procure the necessary amount of the commodity whenever they need it, at transparent market prices.

1.4. Redundancy of domestic supply system

LNG receiving terminals are basically designed and built to withstand large natural disasters. The 3.11 earthquake in Japan in 2011, however, has proved that the unimaginable could happen even to an LNG receiving terminal and domestic gas supply system. If a country is equipped with a redundant supply system (i.e. multiple LNG receiving terminals connected with pipelines), import of LNG and supply of natural gas can be maintained to some extent even when certain parts of the system are damaged. This means that young/emerging LNG importing countries are at higher risk of losing 100% of their gas supply because of less redundant/connected LNG/gas supply systems in their country.

Since more countries have experience with oil as their fuel source, many have more redundant supply systems, both in terms of geography and capacity, multiple refineries, tank terminals, and pump stations connected with diverse shipping routes and road networks.

For coal, in general, the situation is similar to that of LNG. Due to limited demand (i.e. for power generation and some industries), the domestic supply system is simple. In addition, due to the range in coal quality, provision of coal between different destinations is difficult even in the case of an emergency.

1.5. Stockpile

Stockpiling is a useful tool to enhance supply security. However, the stockpile of LNG is limited compared to oil and coal due to its physical nature (gaseous state in ambient temperature and extremely low temperature required to become liquid). In the case of Japan, LNG importers hold 1–2 weeks' worth of stock in their receiving terminals.

Meanwhile, every International Energy Agency (IEA) member country holds more than 90 days' net import equivalent of oil stock. Many developing countries are trying to hold their own oil stocks as well, along with rising oil imports. For coal, Japanese importers hold about 1 month of stock.

The objective of this study is to develop a generalised procedure to assess the readiness of a country in case of an LNG supply disruption. First, a hypothetical assessment procedure is applied to one country to present how it can be applied and to provide useful policy recommendations. Then, the assessment procedure is further generalised to apply to other countries in the EAS region.

Chapter 2

Disruption Scenarios and Procedure of Assessment

2.1. Selection of a fossil fuel for the study

Table 2.1 summarises the status of fossil fuels used in the EAS region. Coal, oil, natural gas supplied by pipelines and LNG are compared along the supply chain.

Table 2.1. Status of Fossil Fuels Used in the East Asia Summit Region

	Source/ Procurement	Market flexibility	Present usage	Future usage	Transport of fuels	Stock	Supply-chain resilience
Coal	Indigenous/ Import	Medium	Electricity/ Industry	Constant	Flexible	Flexible	High
Oil	Indigenous/ Import	High	Transport/ Industry/ Chemical	Increase	Flexible	Flexible	High
PL gas	Indigenous/ Import	Very low	Electricity/ Industry	Constant	Fixed	Limited	Low
LNG	Import	Low	Electricity/ Industry	Increase	Limited	Limited	Medium

LNG= liquefied natural gas; PL= pipeline
Source: Authors.

Coal is used primarily for power generation. Some EAS countries have indigenous coal resources. The use of coal may increase to meet more demand for electricity and other process industries, but may remain at a relatively constant level due to the environmental concern linked with coal consumption.

Oil is largely used for transportation and various industries. Some EAS countries have indigenous oil resources and also have been investing in overseas upstream business. Thanks to the mature, flexible and redundant capacity and the shale gas/oil revolution originated in the United States, the procurement of oil has now become relatively easy. Oil refineries are generally located at several key locations countrywide. Oil products as well as crude oil can be imported, allowing for a more flexible and resilient oil supply structure. Many countries in the EAS region have already gained a lot of experience importing oil.

The use of natural gas is relatively new compared to coal and oil. Some EAS countries have a variety of natural gas supply sources, including LNG and/or indigenous gas resources and import via international pipelines from neighbouring countries. Supply security is considered very high for indigenous natural gas production because the government can manage it directly. There are many concerns, however, such as the depletion of indigenous natural gas resources in the region. Unlike in Europe and the United States, there is virtually no interconnected gas pipeline network available in ASEAN. The ASEAN Council of Petroleum has recently revised its natural gas security policy, recommending that, rather than solely pursuing a regional natural gas pipeline network, countries in the EAS region should establish a gas spot market and infrastructure that incorporate LNG trade.

While a number of emerging countries in the EAS region have just started or will soon start introducing LNG, careful attention should be paid to the supply security, both commercially and technically. For most countries that have just introduced LNG or virtually have limited demand for LNG in the initial stage, the amount of imported LNG is relatively small, within a few million tonnes. They need to rely on just one or two traditional long-term oil-price-linked contracts. They would need to create more LNG demand to enjoy flexible and diversified procurement. LNG in general requires more technical effort to stockpile as compared to coal and oil. The treatment of boil-off gas is essential for LNG storage, limiting the duration of storage. In the introduction phase of LNG or in the period of limited demand, typically just one LNG receiving terminal is operational, supplying regasified natural gas mainly for power generation. A single LNG terminal is responsible for a certain portion of the country's entire power generation, and its power supply is vulnerable. Thus, several LNG receiving terminals are needed, diversified geographically and connected by gas pipelines to be more resilient for natural gas supply.

A disruption of LNG imports could generate serious problems for the country's total energy supply, particularly when the LNG infrastructure is not yet mature. An unexpected disruption of LNG imports may occur at any process in the LNG supply chain, such as gas production, liquefaction, LNG transport, and LNG receiving and regasifying, either due to political, commercial, technical, or environmental reasons. These should be carefully examined.

2.2. Selection of a country for case study

Among emerging EAS countries, one country is selected as suitable for the case study to assess resilience against LNG import disruption. Comprehensive insights and policy recommendations are generated. Finally, a generalised assessment procedure is established, which should be applicable to many other countries in the EAS region.

Thailand is believed to be the most suitable candidate for the case study of LNG import disruption as described below.

Myanmar, the Philippines, Thailand, and Viet Nam are regarded typical 'LNG introducing emerging countries'. They either have just introduced or will soon introduce LNG import. They are somewhat similar in terms of natural gas supply and utilisation. While they all have indigenous gas resources, they require LNG import to meet increasing demand for economic growth. A major part of indigenous natural gas is used for power generation, and LNG import is expected to supplement the shortage of indigenous natural gas. Table 2.2 summarises natural gas utilisation in Myanmar, the Philippines, Thailand, and Viet Nam.

Table 2.2. Natural Gas Utilisation in Myanmar, the Philippines, Thailand, and Viet Nam

As of 2015		Myanmar	Philippines	Thailand	Viet Nam
Natural gas in total primary energy supply[a]		15%	6%	28%	13%
Natural gas in power generation[a]		39%	23%	71%	33%
Natural gas sources (bcm / %)[b]	Indigenous	3.48 / 100% (total 17.5 bcm)	3.47 / 100%	33.0 / 68%	11.3 / 100%
	PL import	–	–	11.7 / 24%	–
	LNG	–	–	3.6 / 7%	–
	Total	3.48 /100%	3.47 /100%	48.3 /100%	11.3 /100%
Natural gas for power gen. (bcm / % in total natural gas consumption)[b]		2.29 / 66%	3.28 / 96%	29.6 / 61%	9.50 / 83%
Power generated in 2015		16 TWh	82 TWh	178 TWh	153 TWh
LNG receiving terminals		Under planning	Under planning	In operation: 1, under construction: 1	Under planning
LNG or PL import in power generation	2015 (actual)	0	0	5% PL import: 17%	0
	2020-2025 (estimated)	1–5%	1–5%	15–25% PL import: 5%	5–10%
	After 2030 (estimated)	5–10%	5–10%	approx. 30% PL import: 0%	10–20%

bcm = billion cubic metres; LNG = liquefied natural gas; PL = pipeline; TWh = terawatt-hour
Sources: [a] Institute of Energy Economics, Japan, [b] International Energy Agency natural gas information; data collected and summarised by authors.

Myanmar, which self-supplies as much as 400% of the country's natural gas, is planning to import LNG to meet increasing demand for electricity in the near future. Two thirds of natural gas consumed in Myanmar was used for power generation in 2015.

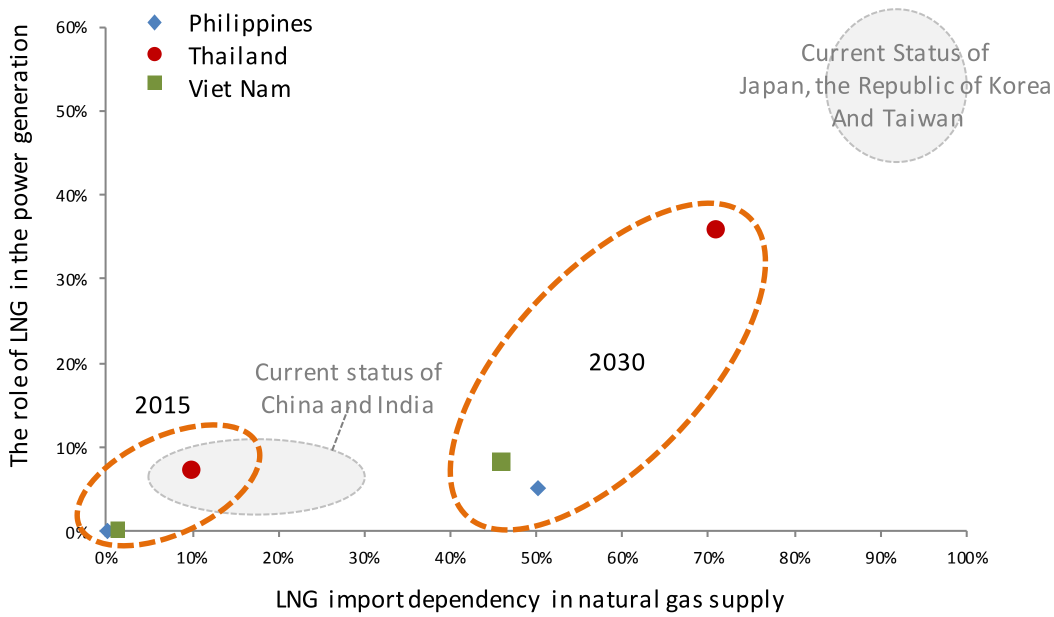
The Philippines and Viet Nam are currently self-sufficient in terms of natural gas supply with indigenous gas production. In 2015, most indigenous natural gas was used for power generation (83% in Viet Nam and 96% in the Philippines). Both countries, however, have been planning to introduce LNG imports to meet increasing demand for electricity. They initially plan to use most imported LNG for power generation, expanding gradually to use in industry.

Thailand has reasonably diversified natural gas supply sources. The country has indigenous natural gas resources and has been importing natural gas from Myanmar via pipeline as well. Furthermore, Thailand has a leading role in LNG imports in the region. In 2015, Thailand relied on natural gas for 71% of its power generation and 31% of natural gas was imported (24% via pipelines and 7% as LNG). This means Thailand relied on imported natural gas for 22% of its power supply, consisting of 17% via pipeline and the remaining 5% as LNG. It should be noted that since approximately 80% of the total LNG was imported from Qatar, Qatari LNG alone was responsible for 6% of the total natural gas supply and 4% of the total power supply to Thailand. Of the total natural gas supplied, 61% was used for power generation.

Figure 2.1 shows LNG import dependence in total natural gas supply and the role of LNG in power generation. Current (2015) and estimated (2030) status of LNG dependence for the Philippines, Thailand and Viet Nam are shown. The current status of LNG dependence for Japan, the Republic of Korea and Taiwan (as matured LNG importing countries) and those for China and India (as other emerging LNG importing countries) are also shown for reference. Dependence on LNG is estimated to increase substantially from 2015 to 2030. Thailand, in particular, is expected to depend heavily on LNG in 2030, approaching current levels for Japan, the Republic of Korea and Taiwan. The Philippines and Viet Nam are expected to follow a similar trend.

Thailand has a full set of natural gas supply sources: indigenous gas resources and gas imports via pipelines and LNG. Thailand will be increasingly dependent on LNG for power generation. It has just entered the expansion phase of LNG projects with viable diversification of LNG sources. Thailand has been leading EAS emerging countries regarding experience in LNG import.

Figure 2.1. LNG Import Dependence in Total Natural Gas Supply and the Role of LNG in Power Generation

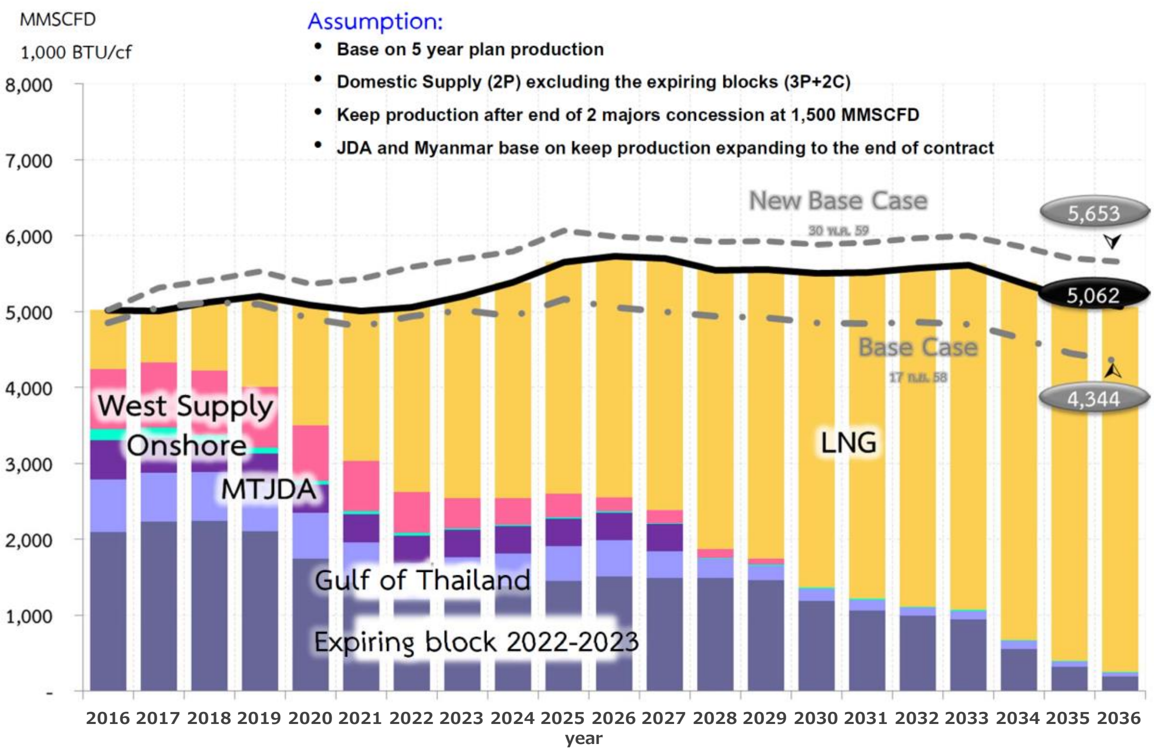


LNG = liquefied natural gas.
Source: International Group of Liquefied Natural Gas Importers (GIIGNL) 2017, BP Statistical Review 2017, Asian LNG Demand-Key Drivers and Outlook (Oxford institute for energy studies, Apr 2016), Philippines LNG-Developing New Import Markets (The Latau Group Nov. 2014), and Thailand's Gas Plan (Ministry of Energy, June 2017); data collected and summarised by authors.

2.3. Overview of natural gas status in Thailand

Figure 2.2 shows gas supply plan in Thailand. After 2020, a substantial decrease in Thai indigenous natural gas production is expected from onshore, Malaysia Thailand Joint Development Area (MTJDA), and Gulf of Thailand supply. Natural gas imports from Myanmar via pipelines (shown as 'West Supply') are also expected to decrease sharply. A substantial increase in LNG imports is essential to compensate for the decrease in indigenous gas production and pipeline gas imported from Myanmar. On top of this, more LNG will be needed to meet increasing demand for natural gas. Dependence on imported natural gas was 31% in 2015, which will jump up to 50% in 2020. In 2030 when the pipeline import is supposedly terminated, LNG will be responsible for 70% of the total natural gas supply. Indigenous natural gas production will be depleted after 2030, suggesting that eventually Thailand's natural gas supply will become almost 100% dependent on LNG import.

Figure 2.2. Gas Supply Plan in Thailand



BTU = British thermal unit, LNG = liquefied natural gas, MMSCFD = million standard cubic feet per day, MTJDA = Malaysia Thailand Joint Development Area, JDA =Joint Development Area (Malaysia-Thailand), 2P = proved plus probable reserves, 3P = proved plus probable plus possible reserves, 2C = contingent proved plus probable resources

Note: 'West Supply' refers to natural gas import via pipeline from Myanmar. In the original figure the timeline was expressed in the Buddhist calendar. It has been rewritten using the AD by the authors.

Source: Thailand's Gas Plan 2015 (2015–2036) (revised in 2016), Dr Sarawut Kaewtathip, Department of Mineral Fuels, Ministry of Energy, 26 June 2017.

Table 2.3 summarises Thailand's LNG procurement. Qatar has been the major LNG supplier in the last several years. It is the first long-term supplier to Thailand with 2 mmtpa (million metric tonnes per annum) of LNG for 20 years. With additional spot LNG supply, Thailand depended heavily on Qatar for more than two thirds of the imported LNG in 2015 and 2016. In 2017, Map Ta Phut LNG receiving terminal, the first and only terminal in Thailand, will be expanded to double its receiving capacity from 5 mmtpa (one train) to 10 mmtpa (two trains). Thailand will be able to diversify LNG sources, with three more independent long-term contracts of approximately 1 mmtpa each. The country is entering into an expansion phase of LNG import, after several years in the introduction phase with only one long-term contract.

Table 2.3. Thailand's LNG Procurement (bcm/yr)

Year	Total	Country of origin
2016	4.2	Qatar 4.1, Oman 0.1 – long term + spot basis
2015	3.6	Qatar 2.9, Australia 0.3, Nigeria 0.2 – long term + spot basis
2014	1.9	Qatar 1.3, Nigeria 0.2, Malaysia 0.1, Yemen 0.1, Oman 0.1, Russian Federation 0.1 – spot
2013	2.0	Qatar 1.4, Nigeria 0.3, Yemen 0.1, E. Guinea 0.1, European Union 0.1 – spot basis
2012	1.4	Yemen 0.5, Peru 0.4, Qatar 0.3, Trinidad and Tobago 0.1, Nigeria 0.1 – spot basis
2011	1.0	Qatar 0.3, Peru 0.3, Russian Federation 0.2, Nigeria 0.2 – spot basis
Long term contracts		
・ Qatar LNG		: 2.0 mmtpa (2.76 bcm/yr) (2013–2032, 20 yrs)
・ BP portfolio		: 1.0 mmtpa (1.38 bcm/yr) (2017–2031, 15 yrs)
・ Shell portfolio		: 1.0 mmtpa (1.38 bcm/yr) (2017–2031, 15 yrs)
・ Petronas portfolio		: 1.2 mmtpa (1.66 bcm/yr) (2017–2031, 15 yrs, ramp-up basis)

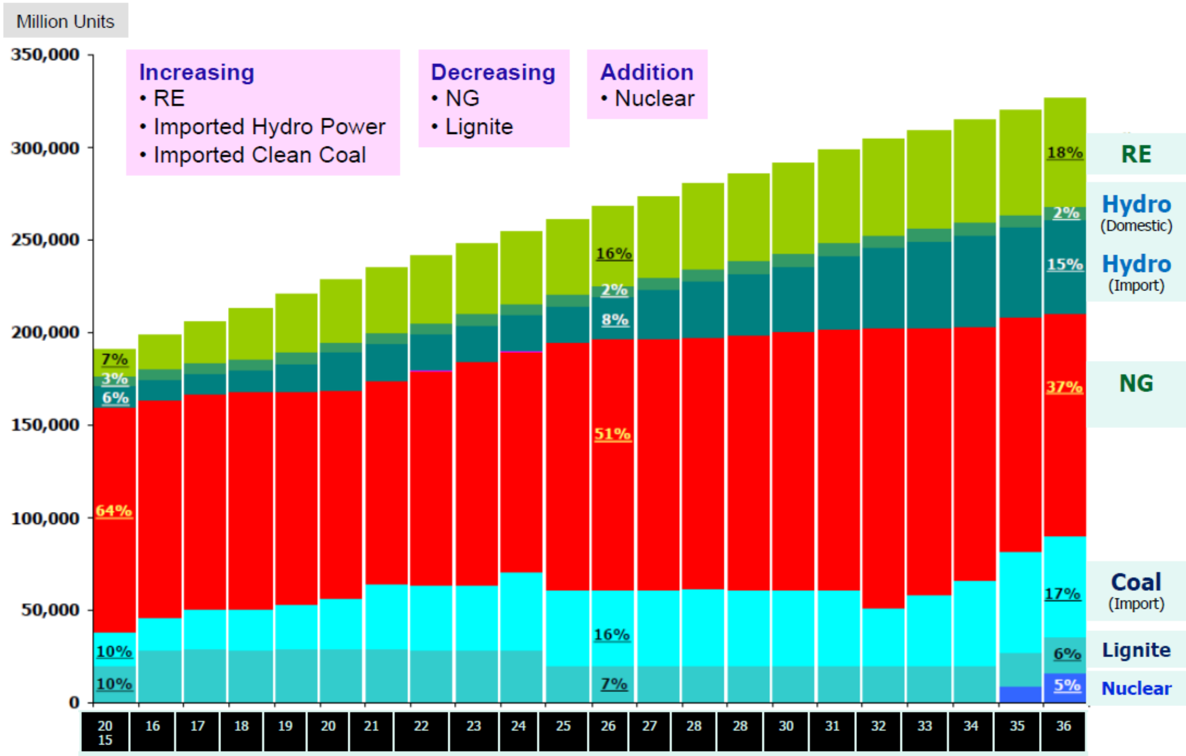
bcm = billion cubic meters, LNG = liquefied natural gas, mmtpa = million metric tonnes per annum, yr = year.

Source: BP Statistical Review-2016; data collected and summarised by authors.

Figure 2.3 shows power generation by fuel type in Thailand. While the total demand is expected to increase steadily, the capacity of natural-gas-powered generation will be maintained virtually unchanged until 2030. The share of natural gas in power generation decreases gradually from approximately 60% in 2015-2016 to 50% in 2020-2025 and less than 40% after 2030. While the share of natural gas is gradually decreasing, a sharp increase in LNG import is planned as was shown in Figure 2.2. This will eventually result in more dependence on LNG in the total power generation. The share of LNG in power generation, which used to be just 5% in 2015, is expected to jump up to 15% in 2020, 25% in 2025, and 30% in 2030. LNG will be increasingly and inevitably crucial for energy supply security in Thailand.

It should be noted again that Myanmar, the Philippines and Viet Nam are expected to follow a similar trend as shown in Table 2.2. These three countries will soon start importing LNG. In the coming decade up to 2030, Myanmar and the Philippines are estimated to rely on LNG import for approximately 5% of total power generation. Viet Nam is somewhere between these two countries, and Thailand will rely on LNG import for approximately 10% of total power generation.

Figure 2.3. Power Generation by Fuel Type in Thailand



NG = natural gas, RE = renewable energy.
Source: Dawan Wiwattanadate, Thailand's Integrated Energy Blueprint (2015–2036).

2.4. General idea on the risk assessment for LNG disruption

A variety of risk assessment methods have been proposed and utilised. In general, risk sources are identified and categorised first. Then risk sources are viewed both quantitatively and qualitatively. Basic categorisation is classifies risk sources as 'Intentional' and 'Non-intentional', which are also called as 'Threads' and 'Hazards' respectively. Another categorisation is according to the origins of risk such as 'Political', 'Economic', 'Technical' and 'Environmental'. Table 2.4 shows a list of example of risk sources, which has been taken as reference from a study on gas risk assessment in European Union. The categorisation of risk sources in the table is applicable to a variety of energy disruptions as well.

Table 2.4. Example of Risk Sources

Intent	Failure/Accident	Nature	Cascade
Acts of terrorism Acts of vandalism Theft (copper/metals) Theft (equipment) Industrial action Targeted cyberattack Virus/trojans Electromagnetic pulse Act of war Diplomatic incident	Negligence Mistake Impact (e.g. vehicle against pylon/pole) Ingress of water Explosion Disclosure of information (theft/leakage) Equipment malfunction or failure Chemical (spillage) Loss, unavailability, or turnover of personnel Outdated and unmaintainable technology	Extreme weather conditions Pandemic (flu/etc.) Geological Fire Flood Solar activity	Loss of power supply/utilities/services Loss of telecoms Loss of energy supply to the electricity transmission network (interconnector / generated supply) Loss of 'black start' capability Loss of pumped storage capacity

Source: Table 2 of Categorisation of sources of risk according to EURACOM project; EURACOM, Del. 2.3 in Ricardo Bolado, Francesco Gracceva, Peter Zeniewski, Pavel Zastera, Lenhard Vanhoorn, and Anna Mengolini (2012), *Best practices and methodological guidelines for conducting gas risk assessments*, JRC Scientific and Technical Reports. Luxembourg: Publications Office of the European Union.

Referring to the examples above, Table 2.5 summarises risk sources for LNG disruption and its estimated amount and duration of disruption. The LNG supply chain is divided into five phases: LNG exporting countries, upstream gas field, LNG liquefaction and loading, LNG transport, and LNG receiving. In each phase of the LNG supply chain, risk sources have been divided into either political or technical. Environmental aspects such as bad weather and natural disaster have been included in the 'technical' category. The amount and duration of LNG disruption are estimated, which are based on experiences by a number of LNG experts in the Republic of Korea and Japan. Note that 'several weeks' in the table is defined as durations longer than 1 week and shorter than 4 month, and 'several months' is longer than 1 month and shorter than half a year or 6 months.

Table 2.5. Risk Sources of LNG Disruption and Its Amount and Duration

		Risk sources for disruption	Estimated amount and period of disruption
LNG exporting countries	Political	・ Default by civil unrest, war, or deteriorated diplomatic relationship ・ Default due to policy change (e.g. prioritising domestic consumption)	・ Years of disruption with either part or entire amount of contracted LNG export ・ A few months of disruption before procuring either part or entire amount of substitute LNG from short-term market
Upstream gas field	Political	・ War or terrorist attack on gas fields or gas pipeline ・ Change in regulation (environment or safety) ・ Labour strikes	・ A few months to one year disruption with either part or entire amount of LNG ・ A few weeks to one month of disruption before procuring substitute LNG from short-term market
	Technical	・ Gas resource depletion ・ Technical or operational failures ・ Natural disaster ・ Utility disruption	・ Depletion predictable ・ A few weeks of disruption due to technical or operational failure ・ Up to a month disruption before procuring substitute LNG from short-term market
LNG liquefaction and loading	Political	・ War or terrorist attack ・ Change in regulation ・ Labour strikes	(same as 'Upstream gas field' above)
	Technical	・ Technical or operational failure ・ Natural disaster ・ Utility disruption	・ A few weeks of disruption from respective LNG project ・ Up to a month disruption before procuring substitute LNG from short-term market
LNG transport	Political	・ Strait blockade by war or deteriorated diplomatic relationship ・ Terrorist or pirates ・ Change in regulation ・ Labour strikes	・ Malacca Strait: One-week disruption for detour/Strait of Hormuz: same as disruption from exporting countries ・ Terrorist or pirates: loss of an LNG carrier, up to a month to charter a substitute. ・ A few weeks for regulation / labour issues
	Technical	・ Stranding/collision ・ Technical failure of an LNG carrier ・ Delay by natural disaster	・ Disruption by loss of an LNG carrier ・ Up to a month to charter a substitute LNG carrier ・ A week delay of delivery by bad weather
LNG receiving	Political	・ Terrorist attack, etc. ・ Change in regulation (environment or safety) ・ Labour strikes	・ A few months to years of disruption depending on the damage to the terminal ・ A few weeks to month for regulation/labour issues
	Technical	・ Natural disaster ・ Technical failure ・ Utility disruption ・ Unable to dock due to serious troubles in a port	・ A few months to years of disruption due to a big disaster, such as a huge tsunami ・ A few days to weeks of disruption due to technical or operational failure and trouble in a port

LNG = liquefied natural gas.
Note: one week < 'a few weeks' < 1 month, 1 month < 'a few months' < half a year.
Source: Authors.

2.4.1 LNG exporting countries

All or part of LNG export could be disrupted by either civil war or a war between countries, in which an exporting country is involved. The Middle East oil crisis in the 1970s and several wars in the region are typical examples. Deterioration of diplomatic relations could also cause disruption. Various disputes between the Russian Federation and Ukraine over the last decade have led the Russian Federation to disrupt natural gas supply to Ukraine, which eventually had enormous impacts on the rest of Europe. Political risks include changes in policy in favour of domestic gas supply. Unless it causes global-scale disturbances, however, the effect of a war is rather limited to respective countries or a region.

The net contracted amount of LNG between the exporting and importing countries could be disrupted, usually in the order of several million tonnes per annum (mmtpa). Substitute LNG could be procured from the international LNG spot market. If the disruption is expected to be long, then LNG importing countries could look for another long-term purchase contract with third-party countries. Depending on the demand-supply status in the global LNG market, substitute LNG could be delivered within several weeks to months if the LNG supply is disrupted from a single exporting country. The duration of disruption could be as long as several months.

The recent dispute between Qatar and its neighbouring countries suggests a possible worst-case scenario. Qatar exported 78 mmtpa of LNG in 2015, which amounted to approximately 31.8% of global LNG exports of 245 mmtpa. There was approximately 66 mmtpa of short-term LNG trade in 2015, which was not enough to cover the potential loss by Qatari LNG disruption. Nevertheless, the global LNG market has been a buyer's market, with approximately 50–100 mmtpa of additional production capacity reportedly available from LNG producing countries. In the current LNG global market, substitute LNG could be procured at most in a few months even if Qatari LNG, the largest supply source, were to be disrupted. It should be recalled also that it took just a few months for Japanese utilities to procure additional 20 mmtpa of LNG to make up for the energy shortage caused by the disaster in 2011.

2.4.2 Upstream gas field and liquefaction

LNG export could be disrupted for months to years if an upstream gas field or a liquefaction facility were to be totally destroyed by a terrorist attack or huge natural disaster. The maximum amount of disruption could be the production capacity of the respective LNG project, from approximately 5 mmtpa for a single standard LNG project to approximately 20 mmtpa for a large-scale project such as in Bintulu, Malaysia. Unless caused by a global-scale disaster or terrorism, the disruption should be limited to the respective projects. Substitute LNG could be procured within several months from the global LNG market. Disruption due to a technical failure or bad weather condition is not uncommon, with its duration ranging from a few days to at most several months. Several hurricanes have caused a lot of damage to various oil/gas infrastructure in the southern states of the United States in recent years, but it took only a few months to resume operations. Every several years, LNG liquefaction facilities require major maintenance lasting a few months, during which their LNG export is temporarily halted. Arrangements are made between exporting and importing countries as to how to deal with such temporary disruptions. Generally speaking, unless the damage is totally devastating, LNG export is believed to resume within a month.

2.4.3 LNG transport

LNG transport could be disrupted by a war, terrorist attack, or pirating. Stranding and/or collisions sometimes occur also under deteriorated weather conditions. If an LNG carrier is severely damaged, the delivery of one cargo of LNG could be suspended. The loss of LNG could amount to 60,000–130,000 tonnes, depending on the ship's cargo capacity. The damaged LNG carrier could be out of service for a certain period, and it could take several weeks to charter an alternative LNG carrier if needed. Delay in delivery, or disruption duration, is estimated to be several weeks. In 2016, there were approximately 360 LNG carriers operational in the world, with 46 ready for short-term charter (International Gas Union 2017 report). It should be noted that several hundred thousand tonnes of LNG could be procured from the international spot market within a short period of time.

The Malacca Strait and Strait of Hormuz are strategically important for the supply of LNG to the EAS region. The Malacca Strait could become blocked due to various accidents such as a collision or stranding of ships, whether or not involving an LNG carrier. LNG carriers could make a detour through the Lombok Strait, which would cause several days of delay in delivery. A blockade of the Strait of Hormuz, either due to political or technical reasons, could result in the total disruption of Qatari LNG, not to mention oil from the Persian Gulf area. It could have a similar impact as the export embargo of Qatari LNG. If a blockade were to last long, it might become necessary to procure substitute LNG from the spot market, which could take several weeks to months. Additional LNG carriers might need to be chartered if Qatari LNG carriers were trapped in the Persian Gulf.

In 1974, a fully loaded oil tanker collided with another ship at the mouth of Tokyo Bay. The collision caused a huge fire and the oil tanker was stranded. Tokyo Bay was closed for 10 days, during which nearly all marine transports into and out of Tokyo Bay were suspended. Since then, several LNG receiving terminals have been built inside Tokyo Bay. It is widely believed that this accident has led to the efforts to maintain the LNG stock at around 20 days of total demand, twice the suspended duration of 10 days. Marine accidents occurring at bottlenecks of sea lanes might cause serious disruption of LNG as well.

2.4.4 LNG receiving

The longest disruption of LNG could occur if LNG receiving terminals are totally destroyed by, for example, a terrorist attack or huge natural disaster. If major facilities such as LNG tanks and a berth/jetty are destroyed, it could take months or even years to restore the terminal. The tsunami caused by the Great East Japan Earthquake on 11 March 2011 is well-known to have totally devastated the Fukushima No. 1 nuclear power plant. It also struck Minato LNG receiving terminal in the city of Sendai, 300 kilometres north of Tokyo. Although no serious damage was identified for the LNG tank, it took 9 months to repair the entire receiving terminal before it was operational again. (For reference, Figure 2.4 shows a photo taken as the tsunami struck Minato LNG receiving terminal in Sendai on 11 March 2011.)

Figure 2.4. Tsunami at Minato LNG Receiving Terminal in Sendai, Japan

Source: Gas Bureau, City of Sendai, http://www.gas.city.sendai.jp/top/info/2013/05/001936.php

LNG receiving terminals have an LNG storage capacity of up to 10–20 days, allowing them to manage delays of several days up to 2–3 weeks. A delay of several days is not uncommon, for example due to unexpected outage of liquefaction facilities or bad weather conditions en route. Generally, if delivery is delayed for a month, LNG receiving terminals can no longer maintain their planned or rated supply of regasified natural gas.

A global LNG market is being established, where exporting countries and regions are gradually diversified. Hundreds of LNG carriers are in operation to secure the flexibility and redundancy in LNG transportation. However, if a country has just started importing LNG with merely one receiving terminal, this terminal itself could be the most crucial bottleneck in the entire LNG supply chain. To be more specific, a berth/jetty of a receiving terminal is believed to be one of the most crucial facilities of an LNG receiving terminal that determine the supply security of LNG.

A standard-sized, economically preferable LNG receiving terminal with a single berth/jetty has a capacity of approximately 5 mmtpa, which could generate 30–40 terawatt-hours of electricity annually. Referring to Table 2.2, a single standard-sized LNG terminal, if fully operational for power generation alone, could provide potentially more than 20% of the total power generated in Thailand or Viet Nam, 40% in the Philippines, and virtually 200% in Myanmar. For emerging EAS countries, the first LNG project alone could have a substantial impact on the country's power generation portfolio. The impact of a single LNG project is rather small for the developed LNG importers such as Japan, the Republic of Korea, and Taiwan, which already have several LNG terminals in operation to meet much larger demand for power.

2.5. LNG disruption scenarios for Thailand

Based on the consideration above, risk scenarios of LNG disruption for Thailand are formulated and shown in Table 2.6. Four disruption scenarios (A–D) are assumed, consisting of interactions between two different amounts (2 mmtpa and 10 mmtpa) and durations (30 days and 180 days). One of the two cases for disrupted amount is associated with LNG production/export and the other with LNG receiving.

Thailand's largest long-term contract is for Qatari LNG (2 mmtpa), which is considered the most serious risk source in the LNG production/export phase. Thailand has only one LNG receiving terminal whose receiving capacity was recently expanded to 10 mmtpa. The worst disruption scenario in the receiving phase is assumed to be the shutdown of the entire terminal.

A disruption of 30 days represents relatively serious but not fatal disruption scenarios. It generally takes a month to procure additional LNG from the spot market, the same time that it takes to repair a relatively serious failure of a receiving terminal. A disruption of 180 days represents fatal scenarios, in which the delivery of LNG is halted due to global-scale political uncertainty or a large-scale technical failure of a receiving terminal.

Table 2.6. LNG Disruption Scenarios: Amount and Duration for Thailand

		Disrupted amount (annualised amount)	
		Largest long-term contract amount 2 mmtpa	**Capacity of the largest LNG terminal 10 mmtpa***
Disrupted duration	30 days	A	C
	180 days	B	D

LNG = liquefied natural gas, mmtpa = million metric tonnes per annum.
* There is only one terminal in Thailand, thus it is the largest.
Source: Authors.

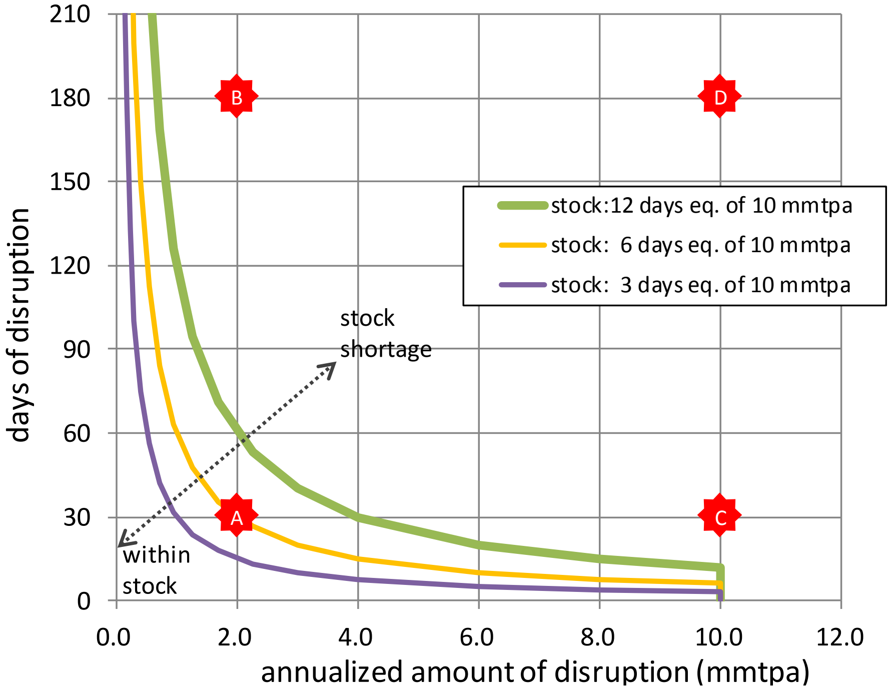
The selection criterion for the two cases of disrupted amount is similar to the 'N–1 principle', which has been widely applied when assessing gas supply security in European Union countries.[1] The N–1 principle is a realistic scenario that describes the technical capacity of the gas infrastructure to satisfy total gas demand in the calculated area in the event of a disruption of the single largest gas infrastructure.

Figure 2.5 illustrates the disruption scenarios and the effect of LNG stock. Each of the four scenarios (A–D) in Table 2.6 is plotted in terms of annualised amount of disruption and days of disruption. Note that the amount of disruption is represented as 'annualised' on an equivalent basis. In the years up to 2020, Map Ta Phut LNG receiving terminal, the only receiving terminal in Thailand, will have a receiving capacity of 10 mmtpa. The LNG stock is reported to be in the order of 10 days at maximum. The three lines in the figure represent the relationship between allowable days of disruption and amount of disruption under three different levels of LNG stock, equivalent to 3, 6, and 12 days of 10 mmtpa LNG receiving.

Under a fixed amount of stock, allowable days of disruption bear an inverse relation to the amount of disruption theoretically. For example, LNG stock equivalent to 6 days of 10 mmtpa (orange line) allows maximum 30 days of the rated supply when LNG disruption is equivalent to 2 mmtpa LNG. This example coincides with disruption scenario A, suggesting that the amount of stock is crucial as to whether or not the disruption is tolerable. Disruption scenario A is therefore in a kind of grey zone, suggesting that countermeasure to LNG disruption should be studied in case of a relatively low level of stock. Under scenarios B, C, and D, due to the shortage of stock, the receiving terminal is no longer able to maintain its rated supply of gasified natural gas over the days of disruption.

[1] Regulation (EU) No. 994/2010 of the European Parliament and of the Council of 20 October 2010, concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.

Figure 2.5. Disruption Scenarios and the Effect of LNG Stock



LNG = liquefied natural gas, mmtpa = million metric tonnes per annum.
Source: authors

Countries such as the Republic of Korea and Japan have sufficiently diversified LNG exporting countries and regions. Also, a large number of LNG receiving terminals have been built. Thus, LNG disruption from a single export project could have relatively limited impact on the country's total LNG procurement. An unexpected long-term shutdown of an LNG receiving terminal could be compensated by several other existing LNG terminals. A high degree of LNG supply security has been already achieved. In contrast, LNG supply security is rather vulnerable for the EAS countries that are in the introduction phase of LNG import. Like the Thailand case, a single exporting country or project is often dominant in the total LNG procurement. Only one LNG receiving terminal is in operation, and a single serious failure of the terminal could affect the country's entire supply of natural gas.

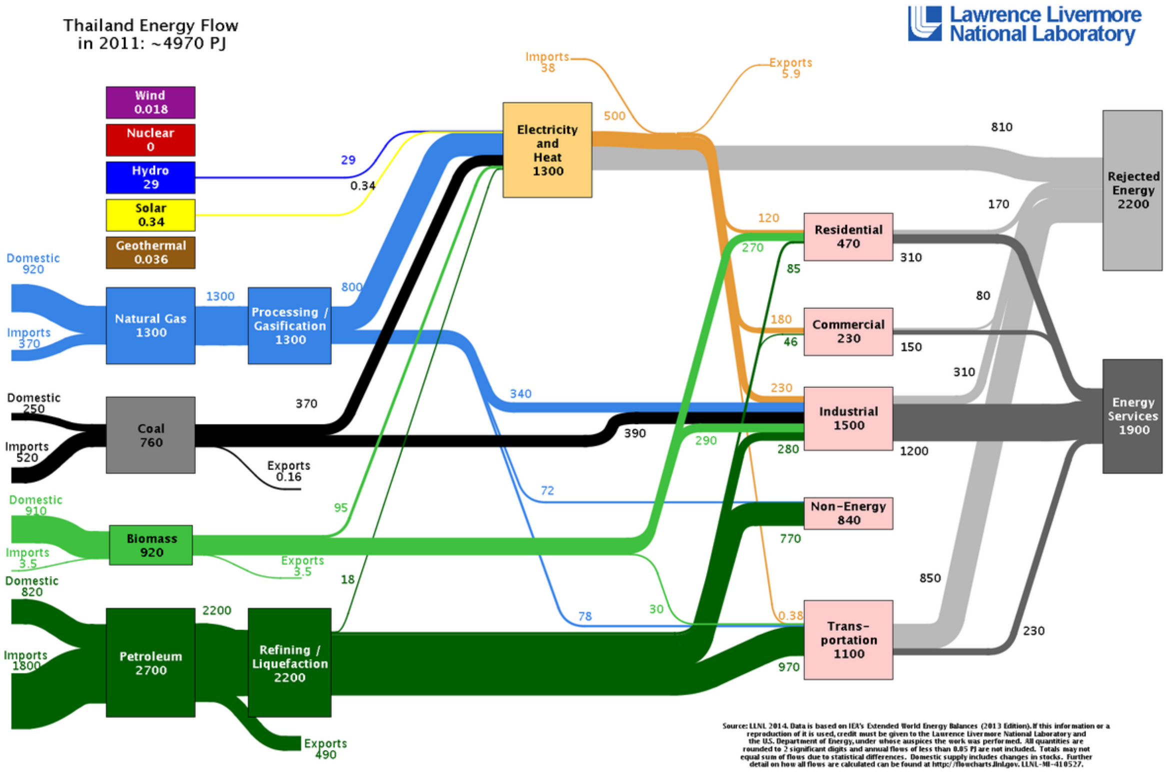
2.6. Assessment procedure of LNG disruption

The major objective of this study is to investigate how to secure the total supply of energy as a whole, and electricity in particular, in the event of an LNG disruption. In this subsection, typical scenarios of LNG import disruption have been identified. The easiest shortcut would be to build LNG tanks to increase the stockpile up to, for example, 90 days as mandated by IEA for oil stock. This could automatically solve most of the disruption scenarios assumed here.

There are many other viable countermeasures, however, by managing the energy supply system totally. As a reference, Figure 2.6 shows the energy flow in Thailand in 2011. Part of the disrupted

LNG could be supplemented by increasing indigenous gas production or gas import via pipelines; part of natural gas could be replaced by other fuels such as oil, coal, and biomass. Some power plants are reportedly ready to deal with dual fuels, allowing oil to replace natural gas. The procurement of substituting fuels should be carefully assessed economically as well as technically. Flexibility and redundancy of the domestic energy supply network play a key role in changing energy sources. Particular considerations should be given to power generation and supply, for which the flexibility and redundancy of power grids should be examined. Detailed knowledge and understanding are essential regarding the energy supply system. Quantitative assessment of the energy supply system is needed to identify potential bottlenecks that constrain the flexibility of the energy supply chain.

Figure 2.6. Energy Flow in Thailand in 2011



Source: Lawrence Livermore National Laboratory

The following generalised countermeasures are proposed. The viability of each countermeasure should be analysed step by step:

0) To use existing LNG stock
1) To increase indigenous natural gas production
2) To increase natural gas import via pipelines
3) To increase the use of other energy sources such as oil, coal, and renewables
5) To increase electricity import
6) To reduce energy export

7) To save energy consumption by means of planned outage of electricity and/or gas
8) To increase LNG storage/stock capacity
9) Other measures

2.6.1 Countermeasures in the event of LNG disruption in Thailand

More specifically for Thailand, these countermeasures can be rewritten as follows:

Step 0: To use existing LNG stock or storage

Step 1: To increase indigenous natural gas production
- Production volume of indigenous gas – e.g. average/max production volume, flexibility, etc.
- Capacity or flexibility of natural gas pipeline network in Thailand – e.g. max flow of natural gas pipeline network, different zones, etc.
- Capacity of gas separation processes, if needed

Step 2: To increase natural gas import from Myanmar
- Import volume of Myanmar gas
- Procurement contracts
- Capacity of the import transmission pipeline
- Capacity or flexibility of natural gas pipeline network in Thailand

Step 3: To increase natural gas from MTJDA
- Production volume of MTJDA gas delivered to Thailand
- Procurement contracts
- Capacity of the MTJDA transmission pipelines
- Capacity or flexibility of natural gas pipeline network in Thailand

Step 4: To increase the use of other fuel sources such as oil and/or coal for power generation and/or industry gas supply
- Capacity of power plants of oil and/or coal
- Fuel switch from natural gas to other fuels
- Capacity or flexibility of power supply network in Thailand
- Stock of oil and/or coal

  (Note: Increased amount of imported oil and/or coal is assumed marginal in the global market)

Step 5: To increase electricity import, if possible

Step 6: To reduce energy export, if possible and substantial

Step 7: To save energy consumption
- Planned outage of electricity and/or city gas supply

Step 8: To increase LNG storage/stock

Step 9: Other measures

Chapter 3

Assessment of Resilience against Liquefied Natural Gas Import Disruptions in Thailand

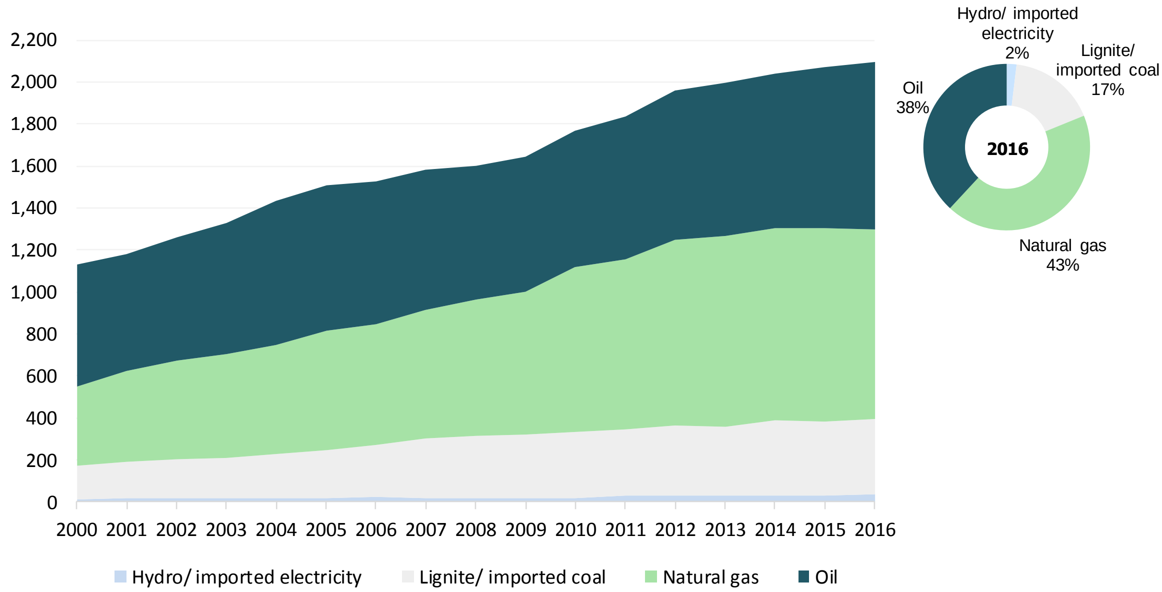
As a case study to apply the assessment procedure developed in the Chapter 2, the study assessed the resilience against LNG import disruptions in Thailand.[2] Prior to the assessment, the Petroleum Institute of Thailand (PTIT) was provided with scenarios of LNG import disruption and possible countermeasures presented in the previous section. PTIT, with using its varied and in-depth information and expertise on the energy supply system in Thailand, assessed the country's resilience to the LNG import disruption scenarios. This chapter presents the results of the PTIT assessment study.

3.1. Background on Natural Gas Market and Infrastructure in Thailand

Thailand's energy use reflects its expanding economic activities, which generally trend with the world's economy. Non-renewable fossil fuels constitute most of the energy use in the country; and although Thailand can produce some of its energy, indigenous supply is rather limited. The country has to rely on energy imports. In addition, Thailand relies only on several sources of energy – with natural gas being the most heavily consumed. In 2016, natural gas consumption averaged 901 kboed (thousand barrels of crude oil equivalent per day) and made up 43% of the country's total commercial primary energy consumption of 2,093 kboed – followed by oil at 798 kboed (38%), lignite/imported coal at 355 kboed (17%), and hydro/imported electricity at 40 kboed (2%).

[2] This part of the study was conducted by the Petroleum Institute of Thailand (PTIT).

Figure 3.1. Commercial Primary Energy Consumption in Thailand



Source: Energy Policy and Planning Office Ministry of Energy; data collected and summarised by the Petroleum Institute of Thailand.

3.1.1 Natural gas market in Thailand

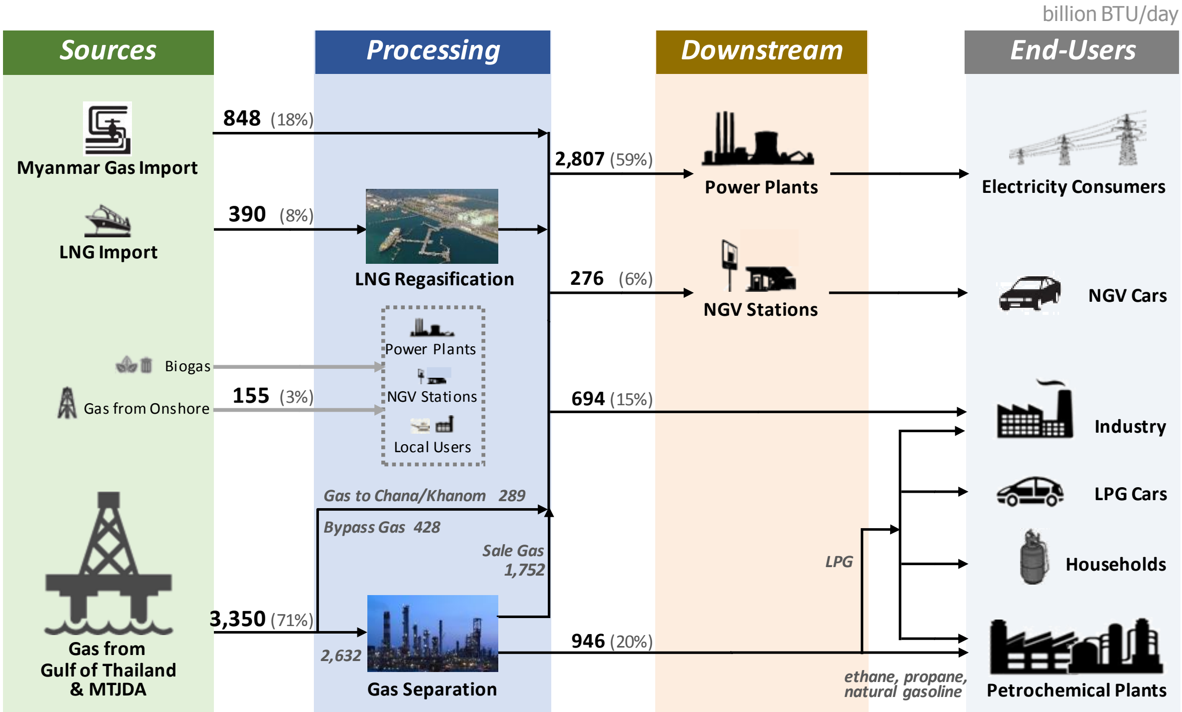
Thailand is both a producer and an importer of natural gas. The country produces natural gas from offshore fields in the Gulf of Thailand and the Malaysia–Thailand Joint Development Area (MTJDA) and from onshore fields in the north and northeast. Indigenous gas, however, does not suffice for the country's demand; thus necessitating piped gas imports from Myanmar and LNG imports.

Figure 3.2 summarises the natural gas supply chain in Thailand. In 2016, Thailand consumed altogether 4,723 billion British thermal units per day (billion BTU/day)[3] of natural gas, consisting of 2,807 billion BTU/day for electricity generation (equivalent to 59% of total natural gas demand), 276 billion BTU/day as natural gas for vehicles (NGV) (6%), 694 billion BTU/day for industrial use (15%), and 946 billion BTU/day by gas separation plants to extract ethane, propane, liquefied petroleum gas (LPG), and other hydrocarbons[4] (20%).

[3] In this report, natural gas demand and supply figures are expressed in terms of heating value – that is, in billion BTU/day and 1,000 BTU/scf (standard cubic foot of gas).

[4] Natural gas produced from the Gulf of Thailand is generally 'wet' gas. That is, it is made up of other hydrocarbons (ethane, propane, butane, etc.) besides methane. It is fed into gas separation plants (GSPs) to extract these hydrocarbons for other applications besides simply burning as fuel.

Figure 3.2. Natural Gas Supply Chain in Thailand



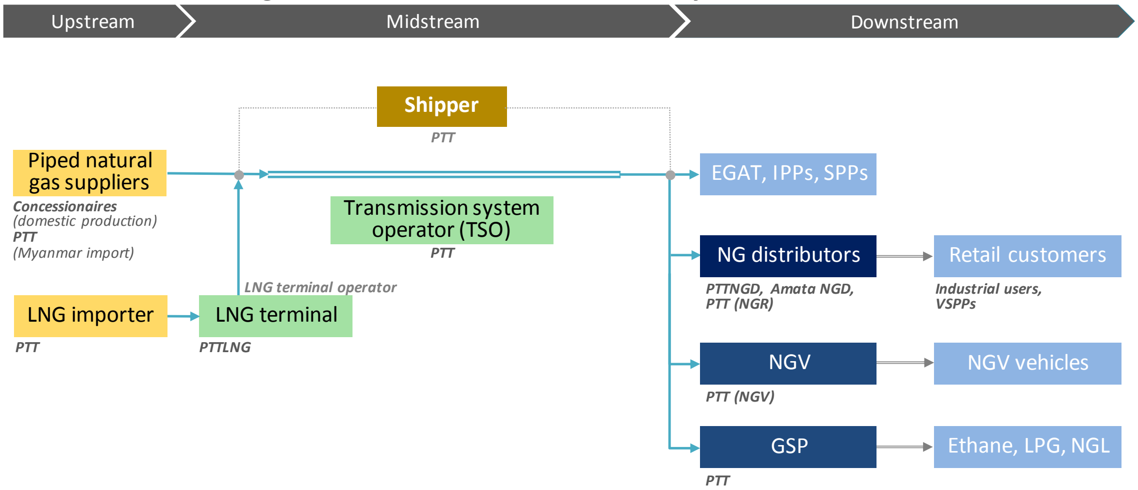
BTU = British thermal unit, LNG = liquefied natural gas, LPG = liquefied petroleum gas, MTJDA = Malaysia–Thailand Joint Development Area, NGV = natural gas for vehicles, scf = standard cubic foot.
Note: Based on 2016 statistics and natural gas supply and demand volumes at 1,000 BTU/scf.
1) Onshore natural gas is stranded; that is, transmission pipelines are not interconnected to the main trunk lines. Hence, it is consumed only by local/nearby power plants, NGV stations and community enterprises. Similarly, there is biogas, which is mainly produced and consumed in nearby small-scale power and industrial plants.
2) Offshore natural gas constituted 2,853 billion BTU/day from the Gulf of Thailand and 497 billion BTU/day from MTJDA.
3) Calculation is subject to rounding off.
Source: Department of Mineral Fuels, Energy Policy and Planning Office, Department of Energy Business, PTT, and Electricity Generating Authority of Thailand; data collected and analysed by the Petroleum Institute of Thailand.

On the supply side, in 2016, Thailand produced 3,350 billion BTU/day of natural gas from the Gulf of Thailand and MTJDA (equivalent to 71% of total natural gas supply) and 155 billion BTU/day from onshore fields (3%), while importing 848 billion BTU/day from Myanmar (18%) and 390 billion BTU/day of LNG (8%) from Qatar and Oman – adding up to 4,743 billion BTU/day.

3.1.2 Natural Gas infrastructure in Thailand

At present, the players in the Thai natural gas market are rather limited in number as shown in Figure 3.3. As energy security is of ultimate concern and natural gas infrastructure requires huge capital investments, PTT as the national oil and gas state enterprise was assigned to operate the whole natural gas industry. Over the years, PTT has become the sole natural gas shipper, the sole transmission system operator, the sole LNG importer, the sole LNG terminal operator (through PTTLNG, a 100% PTT affiliate), a gas distributor, and an NGV retailer.

Figure 3.3. Natural Gas Market Players in Thailand



GSP = gas separation plant, IPP = independent power producer, LPG = liquefied petroleum gas, NG = natural gas, NGL = natural gas liquids, NGD = natural gas distribution company, NGR = natural gas distribution, SPP = small power producer, TSO = transmission system operator, VSPP = very small power producer.

Source: PTT; data collected and analysed the Petroleum Institute of Thailand.

Having PTT, the country's oil and gas state enterprise and flagship, as the key player in the market could be both an advantage and a disadvantage during a crisis. One advantage is that the government could order PTT to promptly take action, while a disadvantage is that a single player's network could be constrained. Realising that liberalisation would improve efficiency through equitable and transparent competition, the country has been liberalising the natural gas market by encouraging more players in the business and limiting the size of the incumbent. In the second half of 2017, the Electricity Generating Authority of Thailand (EGAT) successfully applied for an LNG shipper license to become the second LNG shipper besides PTT.

- **Natural gas transmission network**

Thailand's natural gas transmission network is divided into five different zones as shown in Figure 3.4 :

- **Zone 1**

The offshore gas transmission system off Rayong coast – for transporting most of the Gulf of Thailand and MTJDA gas ashore at Map Ta Phut, Rayong province, for feeding into PTT's gas separation plants (with the volume exceeding the gas separation plants' capacities being bypassed and injected directly into the main onshore transmission network)

- **Zone 2**

The offshore gas transmission system off Khanom coast – for transporting part of the Gulf of Thailand gas ashore at Khanom, Suratthani province, for feeding into PTT's Khanom gas separation plant (GSP #4) to extract methane for the Khanom power plant and LPG

- **Zone 3**

The main onshore gas transmission system spanning over the eastern, central, and western regions – into which bypassed gas from the Gulf of Thailand and MTJDA, sales gas extracted from PTT's gas separation plants in Rayong, LNG and gas imported from Myanmar are injected for delivery to power and industrial plants and NGV stations

- **Zone 4**

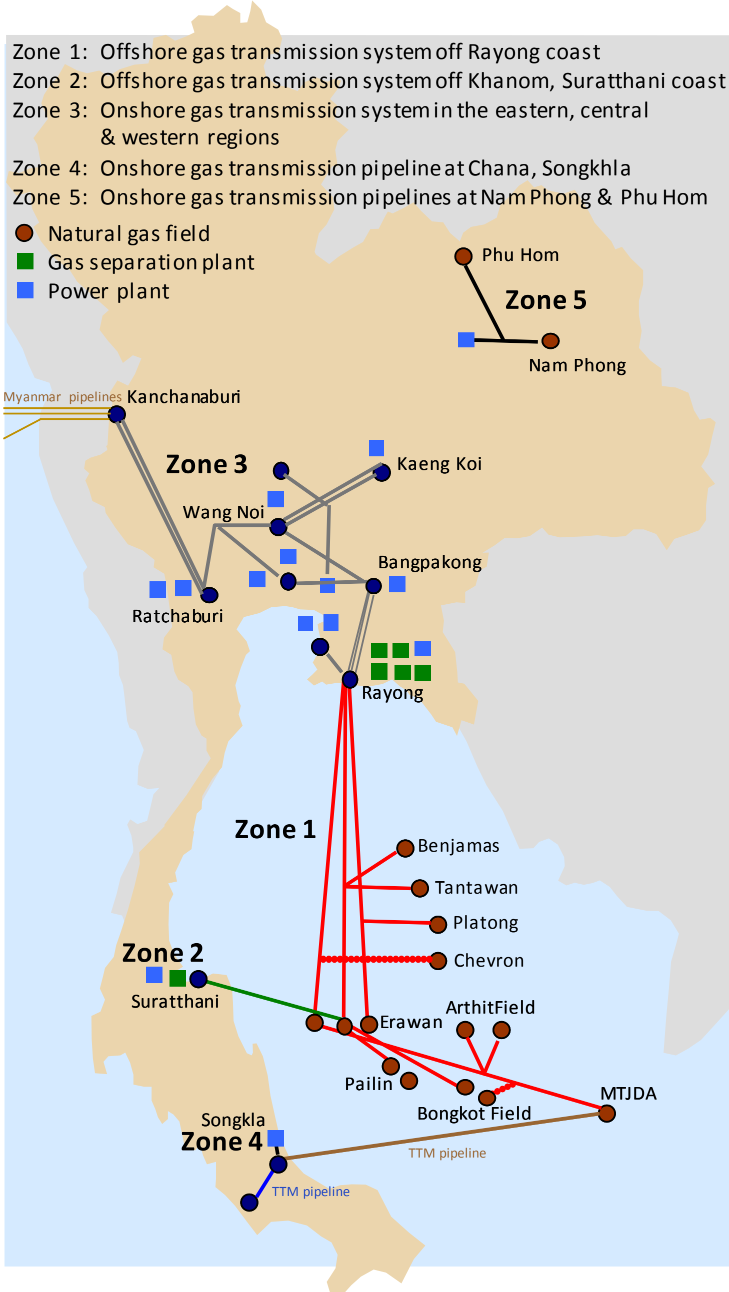
The onshore gas transmission pipeline at Chana, Songkhla – for delivering part of the MTJDA gas to Chana power plant

- **Zone 5**

The onshore gas transmission pipeline at Nam Phong and Phu Hom – for delivery of the onshore gas from Phu Hom and Nam Phong fields to Nam Phong power plant in the northeast.

The purpose of zoning the network is to calculate and collect transmission pipeline tariffs.

Figure 3.4. Natural Gas Pipeline Network in Thailand



MTJDA = Malaysia–Thailand Joint Development Area, TTM = Trans Thailand–Malaysia Gas (Pipeline).
Sources: Energy Policy and Planning Office and PTT; data collected and summarised by the Petroleum Institute of Thailand.

- **LNG terminal**

With rising demand for natural gas, depleting gas reserves in the Gulf of Thailand and MTJDA, and Myanmar's clear-cut policy of no future gas export to Thailand, importing LNG is essential. Presently, Thailand has a single LNG receiving terminal in Map Ta Phut, Rayong province. It is owned and operated by PTT LNG Company Limited (PTTLNG), a wholly-owned subsidiary of PTT.

The LNG terminal completed its first phase of construction with a regasification capacity of 5 million tonne per year and started receiving commercial LNG cargoes in 2011. In 2017, the terminal completed its second phase, expanding its regasification capacity to 10 million tonnes per year as shown in Table 3.1. However, as shown in Figure 3.5, PTTLNG's regasification terminal has not been fully utilised. Before completing the second-phase expansion, terminal utilisation only reached 56% at maximum, equivalent to approximately 390 mmscfd (million standard cubic feet per day) in 2016.

Table 3.1. Existing LNG Receiving Terminal in Map Ta Phut, Rayong, Thailand

Capacity	Phase 1	Phase 2	Total
Regasification (mmtpa / mmscfd)	5 / 700	5 / 700	10 / 1,400
Jetty (no.)	1	1	2
Vessel size (m^3) (max. mmscf)	125,000-264,000 5,720	125,000-264,000 5,720	
LNG tank (m^3 x no.) (mmscf x no.)	160,000 x 2 3,470 x 2	160,000 x 2 3,470 x 2	160,000 x 4 3,470 x 4

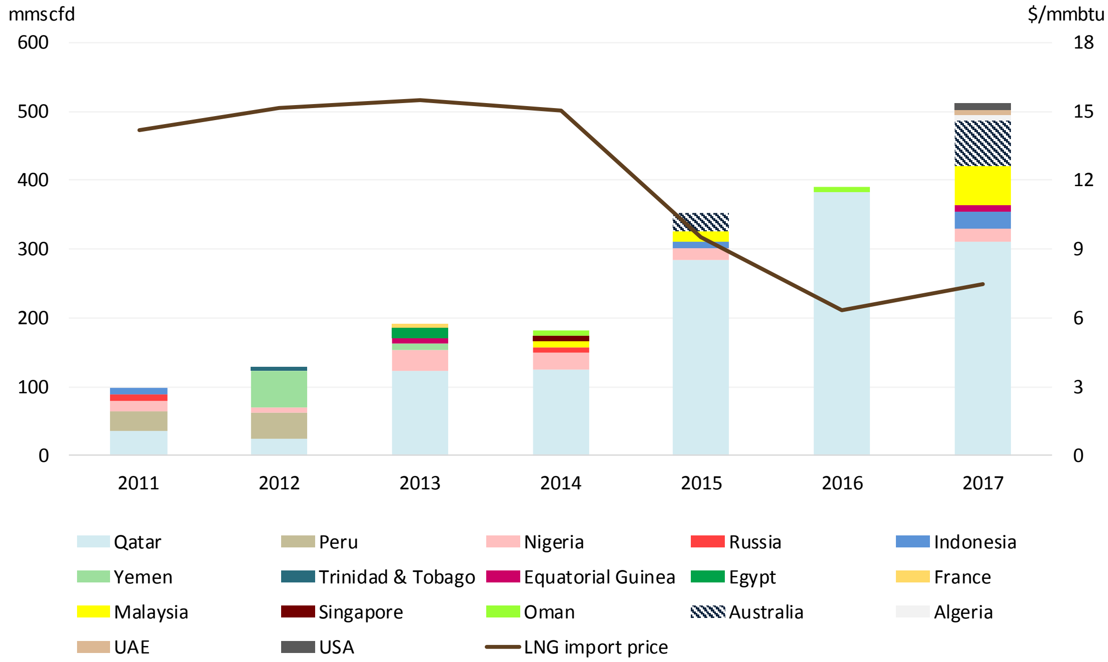
LNG = liquefied natural gas, m^3 = cubic metre, mmtpa = million metric tonne per annum, mmscfd = million standard cubic feet per day.

Note: On 17 September 2015, the National Energy Policy Council, chaired by the Prime Minister, reached a resolution to expand PTTLNG's first receiving terminal by another 1.5 million tonnes per year to 11.5 million tonnes per year. This additional capacity will be brought on stream by 2019.

Sources: PTTLNG, PTT, and Energy Policy and Planning Office; data collected and summarised by the Petroleum Institute of Thailand.

The Ministry of Energy projects LNG imports to rise to 34 million tonnes per year in 2036. It is anticipated that LNG imports will exceed PTTLNG's total regasification capacity of 11.5 million tonnes per year by 2021/22. The country is hence studying the feasibility of constructing another LNG receiving terminal with a capacity of 7.5 million tonne per year in Nong Fab, Rayong, by PTT (PTTLNG) to be operational by 2022 and a 5 million tonne per year floating storage and regasification unit (FSRU) in the upper Gulf of Thailand by EGAT by 2024.

Figure 3.5. Volume and Price of LNG Imports in Thailand



LNG = liquefied natural gas, mmbtu = million British thermal units, mmscfd = million standard cubic feet per day, UAE = United Arab Emirates, USA = United States of America.
Note: LNG import price is the weighted average import price for the year.
Source: Department of Energy Business; data collected and summarised by the Petroleum Institute of Thailand.

- **Natural gas distribution network**

Currently, there are three natural gas distribution system operators/retailers in Thailand: PTT, PTT Natural Gas Distribution Company Limited (PTTNGD), and Amata Natural Gas Distribution Company Limited (Amata NGD). The latter two have PTT as their major shareholder.

Natural gas distribution in Thailand is distinctly segregated. That is, PTTNGD and Amata NGD sell natural gas to industrial users in industrial estates only, while PTT serves customers both inside and outside industrial estates. The three operators oversee their specific service areas/customers, which are generally located in proximity to the main onshore Zone 3 transmission system in the eastern, central, and western regions.

3.1.3 Natural gas quality and flow in Thailand

Having seen the supply/demand overview, the players, and the infrastructure in the Thai gas market, the study now turns to natural gas quality and how natural gas flows in Thailand.

- **East and West Gas quality**

Natural gas from various sources have varying qualities/properties – as measured particularly by the Wobbe Index (WI)[5], which is an indicator of combustion energy output of fuel gas and has a direct impact on the gas-fuelled appliances/machinery in industrial and power plants. For Thailand, the standard WI for designing appliances and machinery to receive Gulf of Thailand and MTJDA gas (the so-called 'East Gas') is between 1,220 and 1,340 BTU/scf ($\pm$ 5%).[6] On the other hand, the standard WI for Myanmar gas is between 970 and 1,040 BTU/scf.[7]

For the East Gas, PTT manages the gas quality by mixing three different gas supplies: (1) sales gas from gas separation plants (GSPs), with carbon dioxide (CO_2) stripped off: WI = 1,330 BTU/scf; (2) bypass gas with 15–20% CO_2 & 0–3% nitrogen gas (N_2): WI = 1,050 BTU/scf; and (3) LNG: WI = 1,380–1,400 BTU/scf (see Figure 3.6). The decline in the Gulf of Thailand gas supply will foremost curb the bypass gas volume and then the sales gas from the GSPs, while the LNG volume will escalate. The shifting proportion of these gases will alter the WI, thus affecting gas users. As of 2017, PTT has already changed the standard WI three times. PTT has projected that it will likely adjust the WI range of the East Gas around 2020 to be between 1,280 and 1,420 BTU/scf – as the LNG (with high WI) import share will rise to over 30% of the total natural gas supply.

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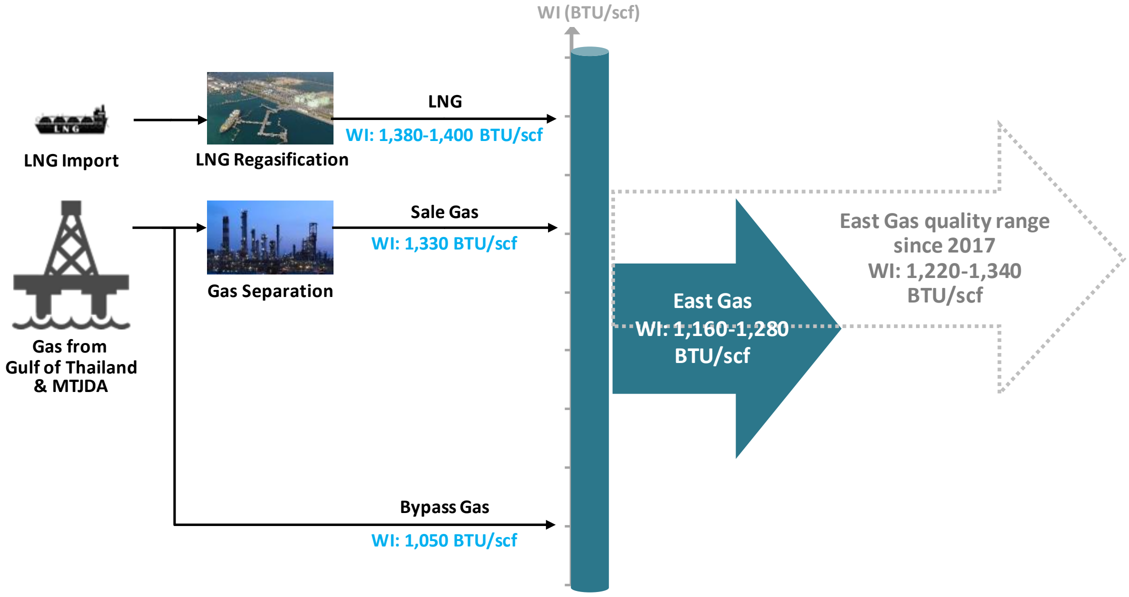
[5] Wobbe Index (WI) indicates the relationship of combustion energy output of a burner and fuel gas property (WI = HHV(dry)/SQR(SG) where HHV = high heating value, SQR(SG) = square root of specific gravity) at constant pressure. In general, the burners can receive fuel gas of $\pm$5% WI – for some up to $\pm$10-15% – with no impact on the combustion process (see PTT website).

[6] In 2017, PTT adjusted the WI range of the East Gas to between 1,220 and 1,340 BTU/scf, meaning that all the industrial and power plants using the East Gas had to adjust their gas-fuelled appliances and machinery to receive the East Gas in the WI range of 1,220–1,340 BTU/scf ($\pm$5%).

[7] Calculated by rounding off from actual HHV(dry) and WI (see PTT website, April 2016). Normally, natural gas import from Myanmar is measured based on its heating value (HV). Yadana gas is N2-rich (more than 24%) compared with Yetagun and Zawtika, resulting in a much lower HV than the other two gases. Yadana gas's HV averages around 720 BTU/scf, Yetagun around 950 BTU/scf, and Zawtika around 900 BTU/scf. When the three gases are mixed and imported to Baan I-Tong, Kanchanaburi province, for injecting into the West Gas transmission system, the average HV stands at 803–858 BTU/scf or in the WI range of 970–1,040 BTU/scf ('West Gas quality').

Figure 3.6. East Gas Quality Management



BTU = British thermal units, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, scf = standard cubic foot, WI = Wobbe Index.

Note: The East Gas WI range of 1,160–1,280 BTU/scf had been effective since July 2010. Then, in 2017, PTT adjusted the WI range of the East Gas to 1,220–1,340 BTU/scf, resulting in all the industrial and power plants using the East Gas having to adjust their gas-fuelled appliances/machinery to receive the East Gas of WI range of 1,220–1,340 BTU/scf (±5%).

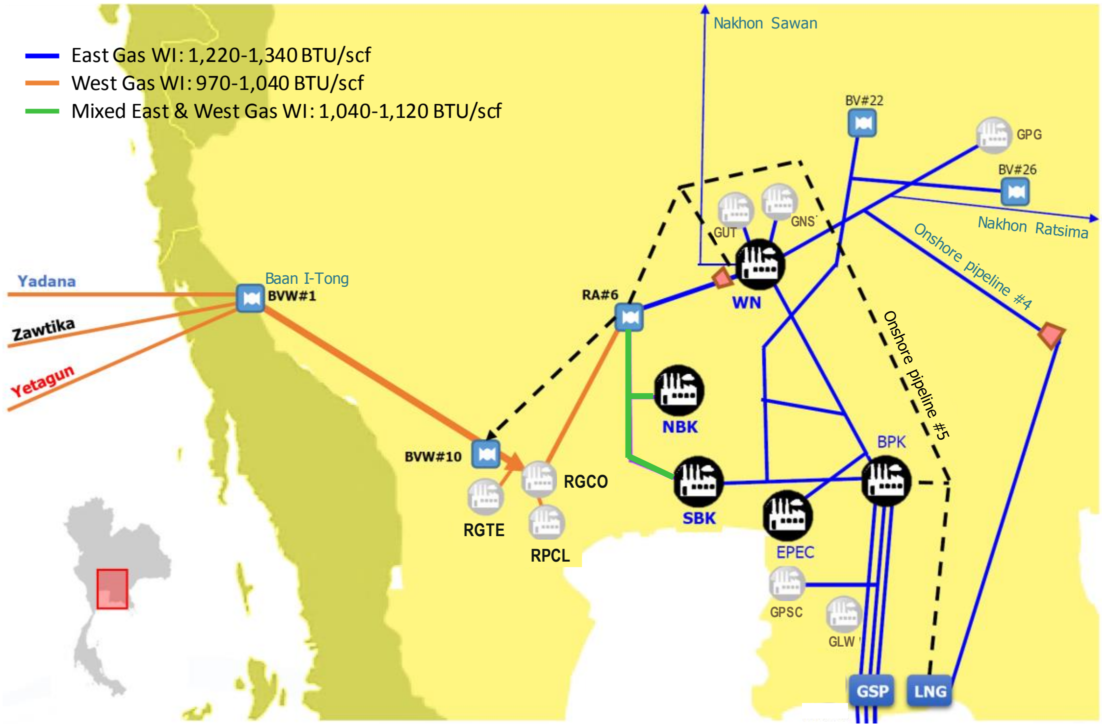
Source: PTT; data collected and summarised by the Petroleum Institute of Thailand.

The West Gas quality management is more complicated and has fewer options than the East Gas due to supply constraints of the Myanmar gas (from Yadana, Yetagun and Zawtika fields) which have caused the quality to decline rapidly. Yadana gas is N_2-rich (over 24%). Its heating value is thus lower than Yetagun and Zawtika gas. The average heating values are around 720 BTU/scf for Yadana, 950 BTU/scf for Yetagun, and 900 BTU/scf for Zawtika. With Yetagun gas production and the daily contract quantity shrinking since 2014, Yetagun gas producers have been experiencing technical problems and have notified PTT of the decline in natural gas reserves and daily contract quantity. PTT must lower its call for Yadana gas (resulting in a take-or-pay) – in order to control/maintain the WI range so that it does not impact gas users' appliances/machinery. Such a decline in daily contract quantity will inevitably affect PTT's natural gas supply management both in terms of quantity and quality.

The RA#6 compression station in Sainoi, Nonthaburi province, is where the East Gas and the West Gas meet and are mixed (see Figure 3.7). The mixed gas, with WI ranging around 1,040–1,120 BTU/scf, is used by EGAT's North Bangkok and South Bangkok power plants.

It can be concluded that natural gas consumption in Thailand is rather 'supply source-specific' and is divided into three distinct areas: the East, the West, and the mixed zone. Disruption of certain supply sources, thus, does have specific regional impacts.

Figure 3.7. Natural Gas Transmission Network in Thailand by Gas Quality

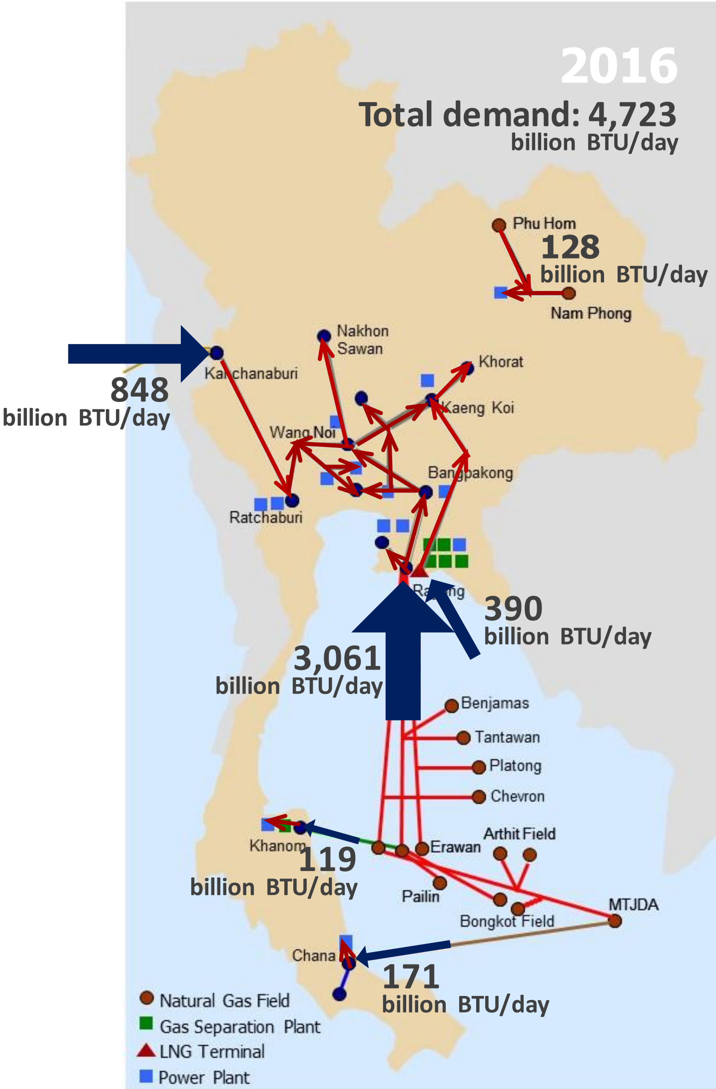


BPK = Bang Pakong power plant, BTU = British thermal units, BV#22, #26 = Block Valve #22, #26, BVW#1, #10 = Block Valve West #1, #10, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, NBK = North Bangkok power plant, RA#6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, SBK = South Bangkok power plant, scf = standard cubic foot, WI = Wobbe Index, WN = Wang Noi power plant

Source: PTT and Energy Policy and Planning Office; data collected and summarised by the Petroleum Institute of Thailand.

- **Thailand's natural gas flow**

Figure 3.8. Natural Gas Flow in Thailand



BTU = British thermal units, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area.

Notes:

1) Only onshore Phu Hom and Nam Phong gas fields are shown on the map, but there is also associated gas produced from Sirikit (26.8 billion BTU/day) and Burapa (0.5 billion BTU/day) oil fields in central-north Thailand. Such associated gas is consumed only by local community enterprises and small nearby power plants. Their pipelines are not connected to the main trunk lines.

2) The volume shown for MTJDA gas that goes ashore at Chana, Songkhla represents only Thailand's portion.

Source: Department of Mineral Fuels, Energy Policy and Planning Office, Department of Energy Business, PTT, Electricity Generating Authority of Thailand; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.8 illustrates the country's natural gas flow. In general, around 96% of the Gulf of Thailand gas and 66% of the MTJDA gas is transported via PTT's offshore transmission pipelines no. 1, 2, and 3 ashore at Map Ta Phut, Rayong, where it is fed into GSPs to extract sales gas (methane) and various hydrocarbons. The sales gas is then injected into the onshore Zone 3 transmission system along with the bypass gas and LNG for consumption by or via power and industrial plants and NGV stations situated in the eastern and central regions. The other 4% of the Gulf of Thailand gas is transported via the Khanom offshore pipeline to be fed into the Khanom gas separation plant (GSP #4) and Khanom power plant, respectively, whereby the remaining 34% of the MTJDA gas goes to Chana power plant in the south.

Imported Myanmar gas is primarily consumed by power plants, NGV stations, and industrial plants in the west, with around 27% mixed with the East Gas (2%) for use by power plants in North and South Bangkok.

As the fields (be they Nam Phong and Sin Phu Hom gas fields in the northeast and Sirikit and Burapa oil fields in the north)[8] are not interconnected with the main trunk lines, onshore natural gas is therefore consumed only within the vicinity – that is, in nearby power plants, community enterprises, and NGV stations.

3.2 Background on the power market in Thailand

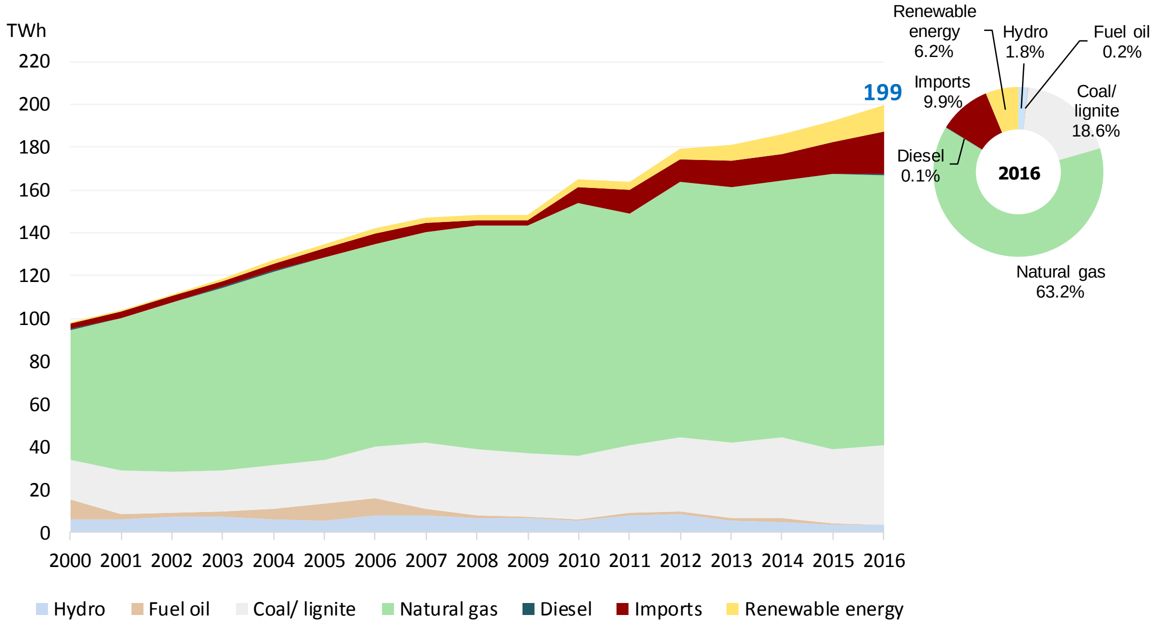
3.2.1 Power market in Thailand

Thailand largely consumes natural gas as fuel in electricity generation as shown in Figure 3.9. Out of the total electricity generated in 2016, over 63% came from natural gas as fuel – followed by coal at 18.6%, electricity imports 9.9%, renewable energy 6.2%, domestic hydroelectricity 1.8%, fuel oil 0.2%, and diesel 0.1%. Generally, power plants in Thailand rarely run on fuel oil and diesel. When a disruption occurs to the natural gas supply, however, the power plants (e.g. thermal power plants, switching between natural gas and fuel oil; or combined cycle power plants, switching between natural gas and diesel) that can also run on these fossil fuels help prevent possible brownouts and/or blackouts.

The majority of the natural gas-fired power plants in Thailand have a form of fuel-switching capability – either to fuel oil or to diesel. Under existing power purchase agreements (PPAs), power plants with fuel-switching capability must demonstrate this ability by operating under the alternative fuel for at least 3–5 consecutive days.

[8] 'Associated gas' is not shown on the map in Figure 3.8.

Figure 3.9. Power Generation by Fuel Type in Thailand



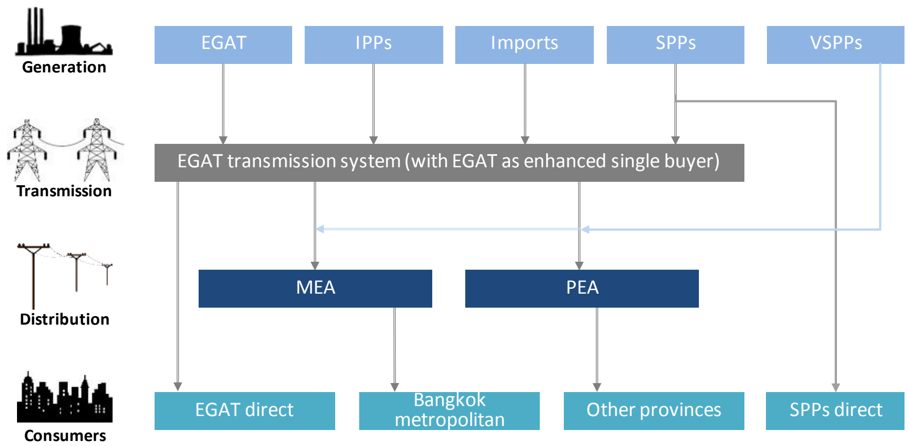
Note: Power generation on the Electricity Generating Authority of Thailand system.
Source: Energy Policy and Planning Office; data collected and analysed by the Petroleum Institute of Thailand.

Like PTT, EGAT – also a state-owned enterprise – is a vertically integrated utility and the key player in Thailand's power sector as shown in Figure 3.10. It owns and operates many power plants (approximately 38% of Thailand's total installed generation capacity). As an enhanced single buyer, EGAT has the exclusive rights to purchase electricity generated by independent power producers (IPPs) and small power producers (SPPs) and sell it to the two state distribution agencies: the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA).

EGAT is the sole owner of the transmission system nationwide. It is also responsible for system operations, including central dispatching of electricity generation.

In 2016, EGAT power plants nationwide consumed a combined total of 941 billion BTU/day of natural gas, while IPPs consumed 1,014 billion BTU/day and SPPs 852 billion BTU/day. Figure 3.11 specifically shows natural gas flow to the gas-fired power plants via the main onshore Zone 3 trunk lines (i.e. excluding the onshore gas in the North, the Northeast, and the Gulf of Thailand and MTJDA gas that goes to Khanom and Chana power plants in the south). Of the total East Gas of 3,450 billion BTU/day, 1,521 billion BTU/day went to EGAT and IPP power plants in the central and eastern regions, and 852 billion BTU/day went to SPPs. Meanwhile, of the total West Gas of 848 billion BTU/day, 575 billion BTU/day went to IPP power plants in Ratchaburi province, and 232 billion BTU/day went to mix with the East Gas of 82 billion BTU/day for consumption by EGAT's North Bangkok and South Bangkok power plants in the mixed gas zone.

Figure 3.10. Power Market Players in Thailand

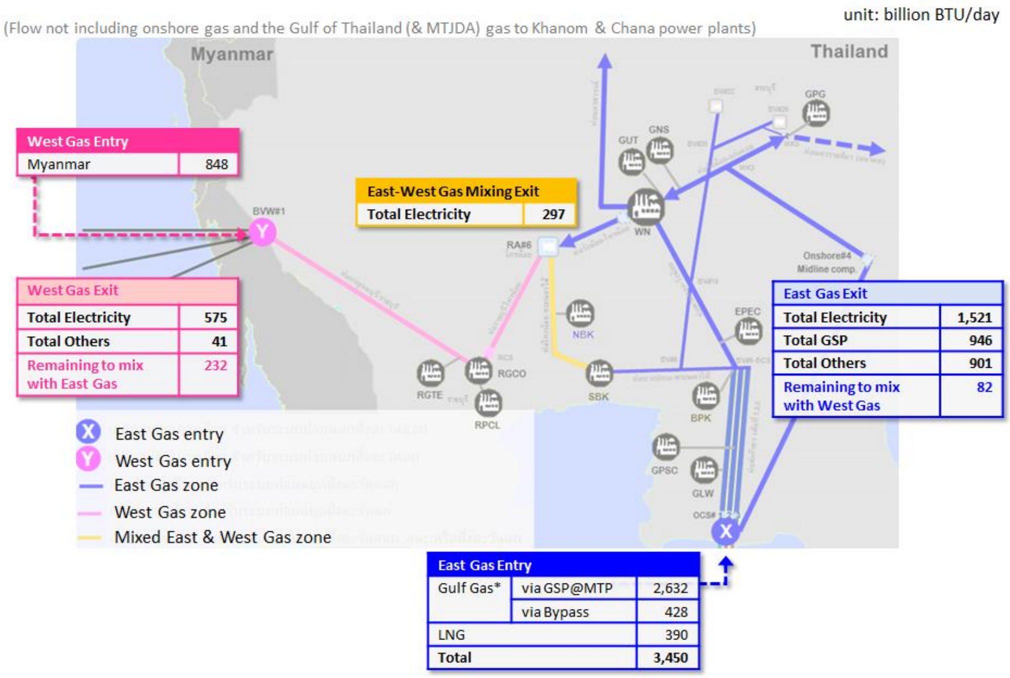


EGAT = Electricity Generating Authority of Thailand, IPP = independent power producers, MEA = Metropolitan Electricity Authority, PEA = Provincial Electricity Authority, SPP = small power producer, VSPP = very small power producer.

Notes: IPPs with generation sold to EGAT > 90 megawatts (MW); SPPs with generation sold to EGAT ±90 MW; VSPPs with generation sold to MEA/PEA ±10 MW.

Source: Office of the Energy Regulatory Commission; data collected and summarised by the Petroleum Institute of Thailand.

Figure 3.11 Main Natural Gas Flow to Power Plants in Central, Eastern and Western Regions in Thailand, 2016



BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 =

Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

One critical point that must be mentioned is that Thailand has a high power reserve margin. Tables 3.2 and 3.3 show the country's total installed power generation capacity in mid-September 2017 of 42,013.2 megawatts (MW), while generation capacity was 26,089 MW. Electricity demand typically peaks during the hottest months of April and May. In 2016, peak demand reached a record high of 29,619 MW in May (Figure 3.12).

Table 3.2. Installed Power Generation Capacity vs Actual Generation in Thailand, by Player

Installed capacity	MW	% share	Generation	MW	% share
EGAT	16,071.1	38.3%	EGAT	8,212	31.5%
IPPs	14,948.5	35.6%	IPPs	8,776	33.6%
SPPs	7,116.0	16.9%	SPPs	5,365	20.6%
Foreign	3,877.6	9.2%	Foreign	3,736	14.3%
Total	**42,013.2**	**100%**	**Total**	**26,089**	**100%**

EGAT = Electricity Generating Authority of Thailand, IPP = independent power producers, MW = megawatt, SPP = small power producer.

Note: Data in mid-September 2017; calculation is subject to rounding off.

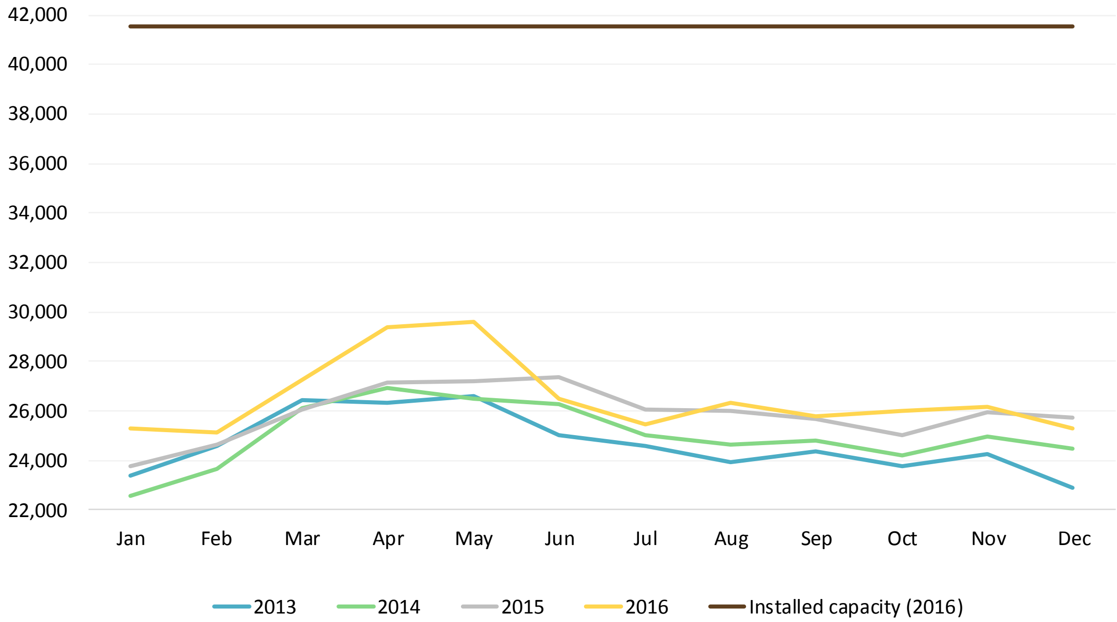
Source: EGAT; data collected and summarised by the Petroleum Institute of Thailand.

Table 3.3. Installed Power Generation Capacity vs Actual Generation in Thailand by Fuel Type

Installed capacity	MW	% share	Generation	MW	% share
Natural gas	27,957.0	66.5%	Natural gas	17,167	65.8%
Renewables	6,869.4	16.4%	Domestic hydropower	417	1.6%
Domestic coal	4,564.0	10.9%	Imported hydropower	1,904	7.3%
Imported coal	1,473.0	3.5%	Other renewables	600	2.3%
Fuel oil	319.5	0.8%	Domestic coal	3,992	15.3%
Diesel	30.4	0.1%	Imported coal	1,565	6.0%
Others	800.0	1.9%	Others	444	1.7%
Total	**42,013.3**	**100.0%**	**Total**	**26,089**	**100.0%**

MW = megawatt.
Note: Data in mid-September 2017; calculation is subject to rounding off.
Source: Electricity Generating Authority of Thailand; data collected and summarised by the Petroleum Institute of Thailand.

Figure 3.12. Monthly Peak Electricity Demand vs Installed Generation Capacity in Thailand, 2013–2016



Source: Energy Policy and Planning Office; data collected and analysed by the Petroleum Institute of Thailand.

3.3 Countermeasures in the event of LNG disruption

3.3.1 Setting the scene

At present, Thailand has four long-term LNG contracts – with Qatar, Shell, BP, and Petronas. They total 5.2 million tonnes per year of LNG. Details of these long-term contracts are shown in Table 3.4.

Table 3.4. Existing Long-Term LNG Contracts in Thailand

Contract partner	Contract volume		Duration	
	mmtpa	mmscfd @1,000 BTU/scf	No. of years	Period
Qatargas	2	280	20	2013–2032
Shell	1	140	15	2017–2032
BP	1	140	20	2017–2037
Petronas	1.2	168	15	2017–2032
Total	**5.2**	**728**		

BTU = British thermal unit, mmscfd = million standard cubic feet per day, mmtpa = million metric tonnes per annum, scf = standard cubic foot.
Note: Period does not necessarily start at the beginning of that calendar year.
Source: Energy Policy and Planning Office; data collected and analysed by the Petroleum Institute of Thailand.

In order to investigate countermeasures that Thailand could take in the event of LNG disruptions, IEEJ has set out four different LNG disruption scenarios as illustrated in Table 3.5.

Table 3.5. LNG Disruption Scenarios

Disruption duration	Disruption to	
	largest long-term contract of 2 mmtpa	existing LNG terminal of 10 mmtpa capacity
30 days	A	C
180 days	B	D

LNG = liquefied natural gas, mmtpa = million metric tonnes per annum.
Source: Authors, refer to Table 2.6.

- **Scenario A: Largest long-term LNG contract of 2 mmtpa disrupted for 30 days**

This is equivalent to the disruption of 280 billion BTU/day or 8% of total natural gas supply to the country for 30 consecutive days, which amounts to 8,400 billion BTU. The impact is minimal as the total disrupted volume is much less than the available LNG stock level.

- **Scenario B: Largest long-term LNG contract of 2 mmtpa disrupted for 180 days**

This is similar to Scenario A but for a more extended period. The daily disrupted volume is also 280 billion BTU/day or 8% of the total natural gas supply. With the disruption duration of 180 days, however, the total disrupted volume amounts to 50,400 billion BTU, which well exceeds the available LNG stock level. Hence, additional countermeasure(s) must be explored.

- **Scenario C: Existing LNG terminal of 10-mmtpa capacity disrupted for 30 days**

In terms of terminal capacity, 10 mmtpa of LNG is equivalent to the disruption of 1,400 billion BTU/day of natural gas supply. However, as illustrated earlier, the LNG terminal is at present not being fully utilised. Prior to completing the second-phase expansion, PTTLNG's terminal utilisation only reached 56% at maximum in 2016, equivalent to approximately 390 billion BTU/day. In 2017, with the terminal's capacity expanded to 10 mmtpa, preliminary data show a maximum LNG import of 693 billion BTU/day and a minimum of 288 billion BTU/day, averaging out around 512 billion BTU/day. Hence, for the analyses in the event of the existing LNG terminal disruption, the resulting disrupted LNG volume is assumed to equal the total long-term contracted volume of 728 billion BTU/day at present[9].

Thus, this is equivalent to the disruption of 728 billion BTU/day or 21% of the total natural gas supply to Thailand for 30 consecutive days, which amounts to 21,840 billion BTU. The impact is clearly perceptible. It would be the equivalent of approximately six 700 MW power plants going offline for 1 month – though the country has lots of spare power generation capacity and fuel-switching capability for most of the gas-fired power plants.

- **Scenario D: Existing LNG terminal of 10-mmtpa capacity disrupted for 180 days**

Using the same logic as for Scenario C, Scenario D is more intensified as the disrupted volume of 728 billion BTU/day (21%) lasts for 180 days – totalling 131,040 billion BTU of natural gas supply shortfall. It is therefore interesting to see if Thailand's high spare power generation capacity and fuel-switching capability could still hold out, or if supplementary countermeasure(s) must be considered.

3.3.2 Investigating possible countermeasures

In the event of LNG import disruption, there are possible countermeasures that Thailand could take as indicated in Table 3.6. The viability as well as the limitations of countermeasures are explored.

[9] This is in line with the latest Ministry of Energy Gas Plan 2015 (as of 8 December 2016) that projects LNG imports to average around 790 billion BTU/day in the next years, before climbing to over 1,400 billion BTU/day in 2020.

Table 3.6. Possible Countermeasures in the Event of LNG Import Disruption in Thailand

<table>
<tr><th>Countermeasures</th><th>Details/remarks/assumptions</th></tr>
<tr><td colspan="2">Step 0: To use existing LNG stock or storage</td></tr>
<tr><td></td><td>With four LNG tanks of 160,000 m^3 or 3,470 mmscf in size each, this amounts to a total of 13,880 mmscf or 13,880 billion BTU of natural gas supply.

If 5% is subtracted for dead stock, the available volume becomes 13,186 billion BTU.</td></tr>
<tr><td colspan="2">Step 1: To increase indigenous natural gas supply (including MTJDA)</td></tr>
<tr><td>1.1 Indigenous gas supply volumes</td><td>
<table>
<tr><th>Total supply volume in 2016:</th><th>billion BTU/day</th></tr>
<tr><td>Gulf of Thailand</td><td>2,853</td></tr>
<tr><td>MTJDA (volume delivered to Thailand)</td><td>497</td></tr>
<tr><td>Onshore</td><td>155</td></tr>
<tr><td>Gulf of Thailand + MTJDA at East Gas entry</td><td>3,060</td></tr>
</table>
This analysis will be based on the total East Gas entry volume, because it is the point where the major portion of Gulf of Thailand and MTJDA gas is mixed with LNG and transported through the main onshore transmission system. This is the so-called ‘East Gas’, which constitutes the main portion of Thailand’s natural gas consumption and flow (see Figure 3.11).

This is in line with the Ministry of Energy Gas Plan 2015 (revised 8 December 2016 version), which projects the Gulf of Thailand and MTJDA gas supply to reach a maximum volume of around 3,300 billion BTU/day in 2017/18. If subtracting the Gulf of Thailand gas that goes to Khanom (119 billion BTU/day) and the MTJDA gas that goes to Chana (171 billion BTU/day), the remaining Gulf of Thailand and MTJDA gas volume at the East Gas entry would be 3,010 billion BTU/day. Hence, for this analysis, the supply of the Gulf of Thailand and MTJDA gas for the East Gas entry is assumed to be ramped up to 3,060 billion BTU/day maximum (2016 figure).

Typically, indigenous gas supply has a $\pm$ 15% flexibility. With dwindling reserves (particularly MTJDA supply to last only until 2027), 2016 volumes are kept as the best possible case.

Remark: The onshore gas is not considered in this analysis as there are no pipelines connecting the onshore gas fields to the main onshore transmission network. The onshore gas is consumed only by local/nearby power plants, NGV stations, and community enterprises. Plus, its volume is fairly small.</td></tr>
</table>

Countermeasures	Details/remarks/assumptions
1.2 Natural gas pipeline network for Gulf of Thailand and MTJDA gas	There are three main offshore trunk lines that bring natural gas from the Gulf of Thailand and MTJDA ashore at Map Ta Phut, Rayong province, and continue on to constitute the main onshore trunk lines (as shown in Figure 3.4). These pipelines are called the 1st Pipeline, 2nd Pipeline, and 3rd Pipeline. Flow rates reported for them are as follows: Flow (mmscfd) — max 1st Pipeline — 840 2nd Pipeline — 1,137 3rd Pipeline — 1,900 Total — 3,877 In addition, there are separate pipelines that bring a portion of the Gulf of Thailand gas to Khanom, Suratthani province, and a portion of the MTJDA gas to Chana, Songkhla province in the south. These have the following flow rates: Flow (mmscfd) — max Offshore Khanom Pipeline *(Gulf gas)* — 250 TTM Pipeline *(MTJDA gas)* — 425 Hence, the overall pipeline capacity or network for both the Gulf of Thailand and MTJDA gas should not put any limitation on this analysis.
1.3 Capacity of gas separation plants	The total capacity of PTT's gas separation plants #1–6 stands at around 2,800 mmscfd (or billion BTU/day). The main objective of the gas separation plants – particularly, GSP #1–3 and 5–6 located in Map Ta Phut, Rayong – is to maximise extraction of ethane, propane, LPG, and other hydrocarbons ('natural gas liquids' or 'C_2+'), which combines to a maximum of around 950 mmscfd (or billion BTU/day). However, when necessary (e.g. during a natural gas supply shortage), C_2+ extraction from the gas separation plants could be reduced in order to have more sales gas for power generation.
Step 2: To increase natural gas import from Myanmar	
2.1 Myanmar gas import volume	Total import volume in 2016: — billion BTU/day Myanmar gas import — 848 *Yadana* — *419* *Yetagun* — *213* *Zawtika* — *216*

		As already mentioned in Section 3.1.3, importing Myanmar gas is a rather complicated issue in itself due to the differing heating values of the various fields and the rapidly shrinking Yetagun gas production. Natural gas from Yadana is N_2-rich and, thus, has a much lower heating value than the gas from Yetagun and Zawtika. Therefore, there must be a 'balanced' combination of supply among the Yadana, Yetagun, and Zawtika gas fields in order for Thailand to receive the gas that can meet the country's West Gas quality range. For this analysis, the option of increasing Myanmar gas import is hence omitted.
2.2	Natural gas pipeline network for Myanmar gas import	The Yadana, Yetagun, and Zawtika gas fields are all located in the Gulf of Martaban, Myanmar. Gas from these fields is transported via distinct offshore and onshore transmission pipelines before being combined at the border and piped into Thailand's main onshore transmission network at BW#1 at Ban I-tong, Kanchanaburi province, and then distributed to various gas-fired power plants located in western and central Thailand as well as to industrial plants and NGV service stations. The main trunk line extending from BW#1 has a (maximum) flow rate of 1,100 mmscfd.
Step 3:	To increase LNG import from other suppliers	
		This is a possibility for Scenarios A and B (though for Scenario A, the disruption duration may be too short) – where the contracted LNG volume of 2 mmtpa is disrupted and the LNG terminal can still operate. With the present environment, where continuously growing LNG supply (from Qatar, the United States, Australia, etc.) has led to a supply glut, buyers have more choices for flexible contracting terms. Thailand could consider importing spot/short-term cargoes from Malaysia, Indonesia, or Qatar. This measure has been implemented from time to time.

<table>
<tr><th colspan="2">Countermeasures</th><th>Details/remarks/assumptions</th></tr>
<tr><td colspan="3">Step 4: To increase the use of other fuel sources such as oil and/or coal for power generation</td></tr>
<tr><td>4.1</td><td>Capacity of power plants of oil and/or coal

(see Table 3.3 in Section 3.2.1)</td><td>As discussed in Section 3.2.1, Thailand has lots of spare power generation capacity, with total installed capacity of around 42,000 MW vs peak demand of 29,619 MW.

Specifically, there are 4,564 MW of coal-fired power plants in the country and (almost) all of them are being fully operated due to coal's price competitiveness. Raising power generation by coal-fired plants as natural gas supply is disrupted is thus not an option for this analysis.</td></tr>
<tr><td>4.2</td><td>Fuel switch from natural gas to other fuels</td><td>The majority of the natural gas-fired power plants in Thailand have a form of fuel-switching capability – either to fuel oil (approx. 4,000 MW of installed capacity) or to diesel (approx. 15,500 MW). Under the existing PPAs, power plants with fuel-switching capability must demonstrate this ability by operating under the alternative fuel for at least 3–5 consecutive days.</td></tr>
<tr><td>4.3</td><td>Capacity or flexibility of power supply network in Thailand</td><td>As of January 2018, the country has a total of 33,239.53 circuit-kilometres of transmission and distribution lines at all voltage levels. Approximately 17.5% of the country's transmission network is made up of 500 kV lines.

<table>
<tr><th>Voltage level
(kV)</th><th>Line length
(circuit-kilometre)</th><th>Number of substations</th><th>Transformer capacity
(MVA)</th></tr>
<tr><td>500</td><td>5,830.84</td><td>17</td><td>32,199.78</td></tr>
<tr><td>300</td><td>23.066</td><td>–</td><td>388.02</td></tr>
<tr><td>230</td><td>14,409.59</td><td>79</td><td>59,500.01</td></tr>
<tr><td>132</td><td>8.705</td><td>–</td><td>133.4</td></tr>
<tr><td>115</td><td>12,948.54</td><td>127</td><td>14,668.16</td></tr>
<tr><td>69</td><td>18.8</td><td>–</td><td>–</td></tr>
<tr><td>Total</td><td>33,239.53</td><td>223</td><td>106,889.37</td></tr>
</table>

The power transmission and distribution network is not a concern in the central, eastern, and western regions – which are the subject of this analysis. (However, this may not be so for the south.)</td></tr>
<tr><td>4.4</td><td>Stock of oil and/or coal</td><td>The country's combined cycle power plants that can switch to using diesel must stock diesel for fully operating the plants under their PPAs for at least 3 consecutive days. Based on this calculation, this is equivalent to around 240 million litres of diesel stock at one time.

Meanwhile, thermal power plants that can switch to using fuel oil must stock fuel oil for fully operating the plants under their PPAs for at least 5 consecutive days. Based on this calculation, this is equivalent to around 100 million litres of fuel oil stock at one time.

Presently, Thailand exports around 14 million litres per day of diesel and almost 10 million litres per day of fuel oil. Therefore,</td></tr>
</table>

Countermeasures	Details/remarks/assumptions
	fuel-switching to diesel and fuel oil by certain gas-fired power plants should not be a point of concern in terms of their availability.
	Department of Energy Business statistics for 2017:

million litres/day	Diesel	Fuel oil
Production	73.70	16.05
Import	2.23	0.16
Demand	63.73	5.76
Export	14.37	9.64

Step 5: To increase electricity import, if possible

As of December 2017, Thailand has PPAs with the Lao People's Democratic Republic and Malaysia – with a combined total of 3,877.6 MW.

Power import	MW
Lao People's Democratic Republic	3,577.6
Theun-Hin Boun hydropower	*434.0*
Houay Ho hydropower	*126.0*
Nam Theun 2 hydropower	*948.0*
Nam Ngum 2 hydropower	*596.6*
Hongsa Lignite	*1,473.0*
Malaysia	300.0
Total	3,877.6

Typically, the country receives electricity in full from both neighbours. As far as it is known, there is a reduction margin of 5%, should Thailand requests for less electricity in certain cases for Theun-Hin Boun and Houay Ho PPAs. It is therefore an unlikely option to further increase electricity import from the existing PPAs.

Countermeasures	Details/remarks/assumptions
Step 6: To reduce energy export, if possible	
	At present, Thailand does not export any natural gas. The country does, however, export some electricity to Cambodia, the Lao People’s Democratic Republic, and Malaysia at the borders. The electricity export volume for the past year amounts to around 1,110 GWh, which is merely 0.6% of the country’s annual generation of around 201,070 GWh.
Step 7: To reduce natural gas consumption by sector	
	The National Energy Policy Council at a meeting in July 1996 passed a resolution on natural gas rationing in the event of supply disruption and natural gas shortage. The consideration order for natural gas supply reduction by consumption share runs from item # 6 upward (i.e. item #6 would be the first to be considered for reduction): 1. Users of natural gas as raw materials in the manufacturing process and as petrochemical feedstocks 2. Users of gas in the residential (LPG), transport (NGV and LPG), industrial (methane and LPG), and commercial sectors, who can derive more economic value than just burning natural gas as fuel in power generation and who cannot readily switch to other fuels/forms of energy 3. Power plants: 3.1 EGAT’s combined cycle power plants in operation 3.2 IPP power plants from the first round of bidding 4. Other combined cycle and cogeneration power plants besides those in item #3 5. Industrial and commercial gas users who can readily switch to other fuels/forms of energy 6. Steam and gas turbine power plants However, in reality, the two key stakeholders (i.e. PTT and EGAT), which happen to be both state-owned, would be in serious discussions and planning with the Ministry of Energy to allocate natural gas supply in the event of a natural gas/LNG disruption. It would be ‘easier’ to manage one’s own businesses/affiliates – for example, EGAT to manage their own power plants to switch to other fuels or PTT to manage NGV supply to service stations. To ration gas supply for industrial users, on the other hand, would be less easy as it may result in take-or-pay problems and many users may no longer be able to switch back to fuel oil, for example after they have changed their appliances/machinery to gas-fuelled.

Countermeasures		Details/remarks/assumptions
Step 8:	To save energy consumption	
8.1	Planned outage of electricity	It is possible to devise a plan for an electricity outage (be it a brownout or a blackout), but this would be the very last resort. EGAT, MEA, and PEA would have to work closely on the plan, and public communication and understanding must be promoted.
Step 9:	To increase LNG storage/stock	
		This is a rather long-term proposition. Under the already approved plan by the National Energy Policy Council to expand PTTLNG's Map Ta Phut regasification terminal by another 1.5 mmtpa to 11.5 mmtpa by 2019, no additional LNG storage tank will be built. However, for PTTLNG's second terminal at Nong Fab (also in Rayong province) with a capacity of 7.5 million tonnes per annum to be commercially operational by 2022, two LNG storage tanks of 250,000 m3 in size each will also be constructed.

BTU = British thermal unit, C_2+ = ethane or higher molecular weight components, EGAT = Electricity Generating Authority of Thailand, GWh = gigawatt-hour, IPP = independent power producer, kV = kilovolt, LNG = liquefied natural gas, m3 = cubic meter, MEA = Metropolitan Electricity Authority, mmscf = million standard cubic feet, mmscfd = million standard cubic feet per day, mmtpa = million metric tonnes per annum, MTJDA = Malaysia–Thailand Joint Development Area, MVA = megavolt ampere, MW = megawatt. NGV = natural gas for vehicles, PEA = Provincial Electricity Authority, PPA = power purchase agreement, TTM = Trans Thailand–Malaysia Gas Pipeline.
Note: Assume security at all cost. Any increased amount of imported fuels is assumed marginal in global market.
Source: Petroleum Institute of Thailand.

3.3.3 Assessment results

From the assessment of the four scenarios in comparison with the Base Case, at most up to only four countermeasures (excluding the use of existing LNG stocks as Step 0) are taken. These countermeasures, considered to be some of the most fundamental ones, comprise:

Step 1: to increase indigenous offshore gas supply,

Step 2: to substitute for natural gas shortfall by switching to fuel oil/diesel for power generation,

Step 3: to reduce NGV supply, and

Step 4: to reduce GSP C_2+ extraction.[10]

[10] Extraction of ethane, propane, LPG, and other hydrocarbons ('natural gas liquids' or 'C2+').

Table 3.7 shows these countermeasures and their impacts, and Table 3.8 and Figures 3.13–3.19 quantify them. Please note the differing reference to the step numbers in Table 3.6 and in these tables.

Countermeasures for the four scenarios (A–D) are summarised as follows:

- **Scenario A: Largest long-term LNG contract of 2 mmtpa (equivalent to 280 billion BTU/day) disrupted for 30 days**

Step 0: Use existing LNG stock, which can last for 47 days.
(No more countermeasures needed)

- **Scenario B: Largest long-term LNG contract of 2 mmtpa (equivalent to 280 billion BTU/day) disrupted for 180 days**

Step 0: Use all existing LNG stock, which lasts until day 47.
Step 1: After day 48, increase Gulf of Thailand and MTJDA gas supply from 2,722 BTU/day to 3,002 billion BTU/day.
(No more countermeasures needed)

- **Scenario C: Existing LNG terminal of 10 mmtpa capacity (equivalent to 728 billion BTU/day as the total long-term contracted volume) disrupted for 30 days**

Step 0: Unable to use existing LNG stocks due to the terminal failure.
Step 1: Increase Gulf of Thailand and MTJDA gas supply from 2,722 BTU/day to 3,060 billion BTU/day. Still, a shortfall of 390 billion BTU/day.
Step 2: Switch to fuel oil/diesel use to substitute for the 390 billion BTU/day gas shortfall.
(No more countermeasures needed)

- **Scenario D: Existing LNG terminal of 10-mmtpa capacity (equivalent to 728 billion BTU/day as the total long-term contracted volume) disrupted for 180 days**

Day 1–30:
same as Scenario C
Day 31–180:
Step 0: Unable to use existing LNG stocks due to the terminal failure.
Step 1: Increase Gulf of Thailand and MTJDA gas supply to 3,060 billion BTU/day. Still, a shortfall of 390 billion BTU/day.
Step 2: Use of fuel oil/diesel needs to be lowered to 80% of that in the first month, equivalent to 312 billion BTU/day gas to secure supply of fuel oil/diesel. This leads to yet another gas shortfall of 78 billion BTU/day.
Step 3: Reduce gas supply to NGV by 10% equivalent to 28 billion BTU/day, by switching to gasoline.

Step 4: Reduce GSP (gas separation plant) C_2+ extraction by 5.3%, saving 50 billion BTU/day gas.
(No more countermeasures needed)

In conclusion, Thailand appears to be resilient to LNG import disruption according to this assessment. This could be a result of Thailand's high reserve margin and fuel-switching capability.

Nevertheless, it must be pointed out that LNG in the current assessment constitutes 21% of total natural gas supply at most. If the scenarios were to be evaluated again in 10 years when LNG import is projected to constitute over two-thirds of the country's natural gas supply, necessary countermeasures will prove to be exceedingly intricate. Thailand must consider and plan seriously for its future energy security now.

Table 3.7. Countermeasures Taken and Their Impacts

Countermeasures taken	**Scenario A:** 280 billion BTU/day disrupted for 30 days	**Scenario B:** 280 billion BTU/day disrupted for 180 days	**Scenario C:** 728 billion BTU/day disrupted for 30 days	**Scenario D:** 728 billion BTU/day disrupted for 180 days	
				Day 1–30	Day 31–180
Step 0: Use existing LNG stock	Yes This is more than adequate.	Yes Same as Scenario A But LNG stock lasts only for Day 1–47 Additional countermeasures necessary	No Due to terminal disruption problem	No Due to terminal disruption problem	No Due to terminal disruption problem
Step 1: Increase Gulf of Thailand (including MTJDA) natural gas supply	-	Yes For Day 48–180, have to increase Gulf of Thailand and MTJDA gas supply to 3,002 billion BTU/day	Yes Same as Scenario B But to a higher volume of 3,060 billion BTU/day Still 390 billion BTU/day short.	Yes Same as Scenario C	Yes Same as Scenario C

Countermeasures taken	**Scenario A:** 280 billion BTU/day disrupted for 30 days	**Scenario B:** 280 billion BTU/day disrupted for 180 days	**Scenario C:** 728 billion BTU/day disrupted for 30 days	**Scenario D:** 728 billion BTU/day disrupted for 180 days	
				Day 1–30	Day 31–180
Step 2: Switch to fuel oil/ diesel for some power plants	-	-	Yes Switch to use fuel oil/diesel to substitute for the 390 billion BTU/day gas shortfall. This equates to 2,256 MW of electricity. Approx. 11 million litres/day of fuel oil/diesel are needed (338 million litres total).	Yes Same as Scenario C	Yes Same as Scenario C But needs time to build up fuel oil and diesel stocks spent at power plants, thus only 80% is available after the first month. This equates to 312 billion BTU/day of gas shortfall and 1,805 MW of electricity. Approx. 9 million litres/day of fuel oil/diesel are needed (1,354 million litres total).

Countermeasures taken	Scenario A: 280 billion BTU/day disrupted for 30 days	Scenario B: 280 billion BTU/day disrupted for 180 days	Scenario C: 728 billion BTU/day disrupted for 30 days	Scenario D: 728 billion BTU/day disrupted for 180 days	
				Day 1–30	Day 31–180
Step 3: Reduce NGV supply by 10% (most NGV vehicles are dual-fuelled)	-	-	-	-	Yes NGV consumption in 2016 = 276 billion BTU/day 10% = ~28 billion BTU/day Assume this portion of NGV switches to gasoline (personal cars), 0.9 million litres/day of gasoline are needed
Step 4: Reduce GSP C_2+ extraction	-	-	-	-	Yes Natural gas consumption by GSP to extract C_2+ products in 2016 = 946 billion BTU/day Let 50 billion BTU/day or 5.3% be reduced This is equivalent to approx. 4.9 kilobarrels/ day or 419 tonnes/day of LPG supply reduction from GSP.

Countermeasures taken	**Scenario A:** 280 billion BTU/day disrupted for 30 days	**Scenario B:** 280 billion BTU/day disrupted for 180 days	**Scenario C:** 728 billion BTU/day disrupted for 30 days	**Scenario D:** 728 billion BTU/day disrupted for 180 days	
				Day 1–30	Day 31–180
Impact	No impact on gas users	No impact on gas users	No power shortage but electricity price may not be as competitive. No fuel oil/diesel supply problem as Thailand currently exports fuel oil and diesel. No impact on the West Gas and mixed gas users	No power shortage but electricity price may not be as competitive. No fuel oil/diesel supply problem as Thailand currently exports fuel oil and diesel. No impact on the West Gas and mixed gas users	Ethylene crackers in Thailand have some flexibility between LPG and naphtha. They could be asked to switch from LPG to naphtha for this amount. With local gasoline in oversupply, refineries could flex to distil the equivalent amount of naphtha for the ethylene crackers. Power plants have an extra 78 billion BTU/day of natural gas foregone by NGV and GSP for power generation. No impact on the West Gas and mixed gas users

BTU = British thermal unit, C_2+ = ethane or higher molecular weight components, GSP = gas separation plant, LNG = liquefied natural gas, LPG = liquefied petroleum gas, MTJDA = Malaysia–Thailand Joint Development Area, MW = megawatt, NGV = natural gas for vehicles

Source: the Petroleum Institute of Thailand.

Table 3.8. Natural Gas Volumes at East and West Gas Entry and Exist by Scenario

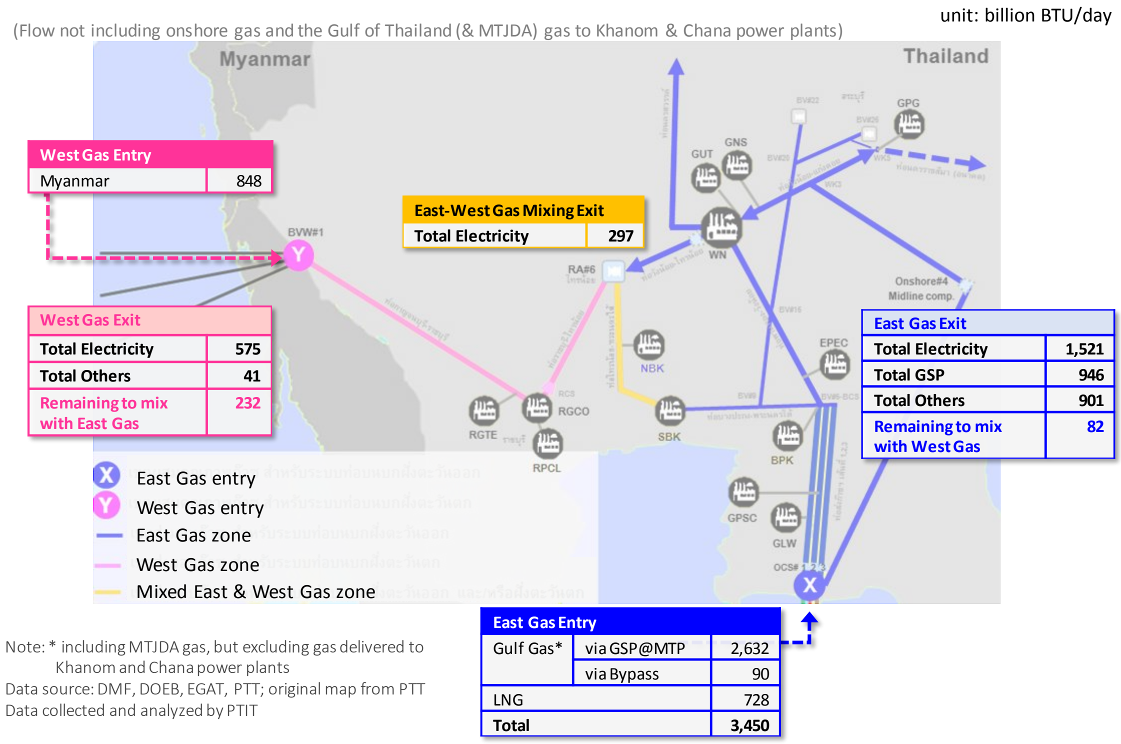
(unit: billion BTU/day)	Base Case	Case A	Case B		Case C	Case D	
East Gas Entry		Day 1–30	Day 1–47	Day 48–180	Day 1–30	Day 1–30	Day 31–180
Gulf Gas (including MTJDA)							
via GSP@MTP	2632	2632	2632				
via Bypass	90	90	90				
Total Gulf Gas (including MTJDA)	2722	2722	2722				
LNG	728	728	728	728			
LNG disrupted		−280	−280	−280	−728	−728	−728
remaining LNG available		448	448	448			
Step #0 use LNG stock		280	280		0	0	
Step #1 increase Gulf of Thailand (including MTJDA) natural gas supply to 3,060 billion BTU/day							
via GSP@MTP				2632	2632	2632	2632
via Bypass				370	428	428	428
Step #2 switch to fuel oil/diesel for some power plants					390	390	312
Step #3 reduce NGV supply by 10%							−28
Step #4 reduce GSP C_2+ extraction							−50
Additional NG for power generation provided by Steps #3 & 4							78
Total	3450	3450	3450	3450	3060	3060	3060
East Gas Exit							
Total Electricity	1521	1521	1521		1521	1521	1521
Step #2 swtich to fuel oil/diesel					390	390	312
Total Electricity East gas consumption after some plants switch to fuel oil/diesel					1131	1131	1131
Additional NG for power generation provided by Steps #3 & 4							78
GSP	946	946	946		946	946	
Step #4 reduce GSP C_2+ extraction							896
Others	901	901	901		901	901	
Step #3 reduce NGV supply by 10% (most NGV vehicles are dual-fuelled)							873
Remaining to mix with West gas	82	82	82		82	82	82
Total	3450	3450	3450		3060	3060	3060
West Gas Entry							
Myanmar	848	848	848		848	848	848
Total	848	848	848		848	848	848
West Gas Exit							
Total Electricity	575	575	575		575	575	575
Others	41	41	41		41	41	41
Remaining to mix with East gas	232	232	232		232	232	232
Total	848	848	848		848	848	848
Mixed East-West Gas Exit							
Total Electricity	297	297	297	297	297	297	297
Total	297	297	297	297	297	297	297

BTU = British thermal unit, C_2+ = ethane or higher molecular weight components, GSP = gas separation unit, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NG = natural gas, NGV = natural gas for vehicles.

Note: Assume security at all cost. Any increased amount of imported fuels is assumed marginal in global market. Natural gas supply and demand volume @ 1,000 BTU/scf.

Source: Petroleum Institute of Thailand.

Figure 3.13. Main Natural Gas Flow in Thailand: Base Case



BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

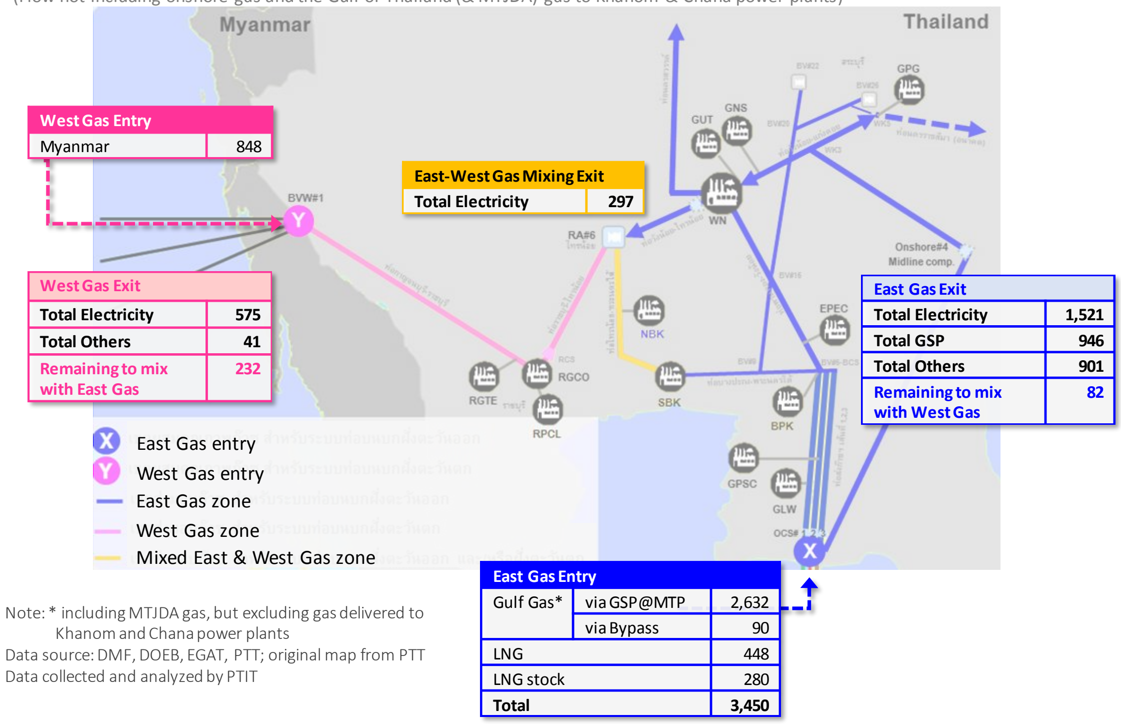
Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.14. Main Natural Gas Flow in Thailand: Scenario A

unit: billion BTU/day

(Flow not including onshore gas and the Gulf of Thailand (& MTJDA) gas to Khanom & Chana power plants)



BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

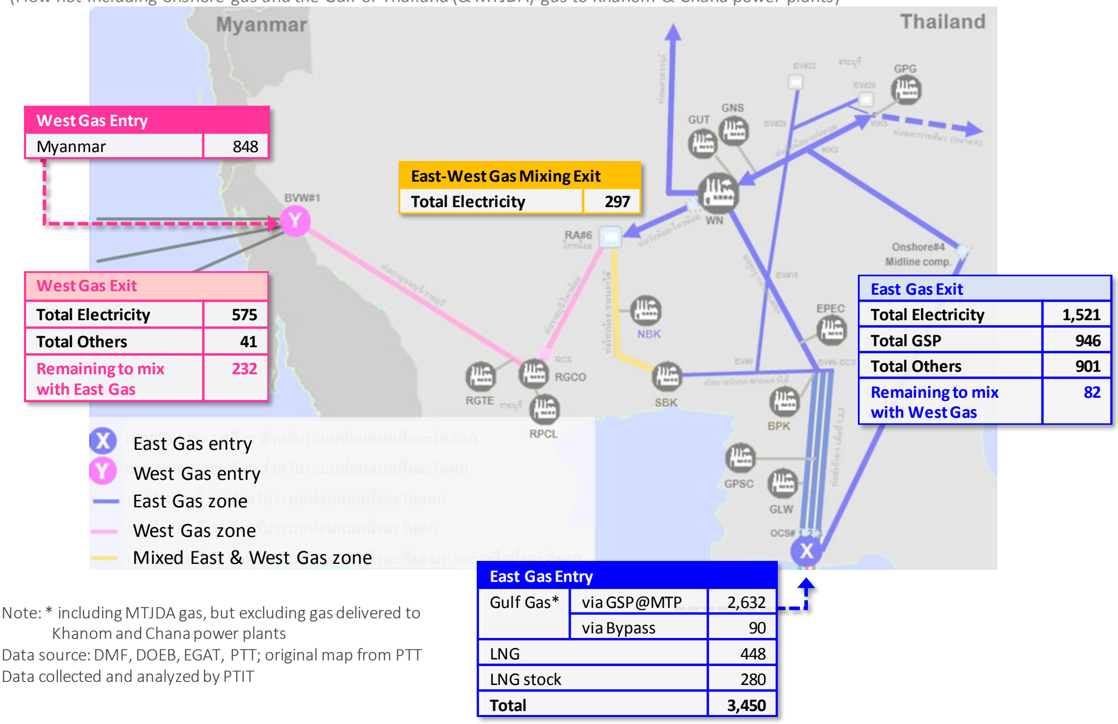
Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.15. Main Natural Gas Flow in Thailand: Scenario B – Day 1–47

unit: billion BTU/day

(Flow not including onshore gas and the Gulf of Thailand (& MTJDA) gas to Khanom & Chana power plants)



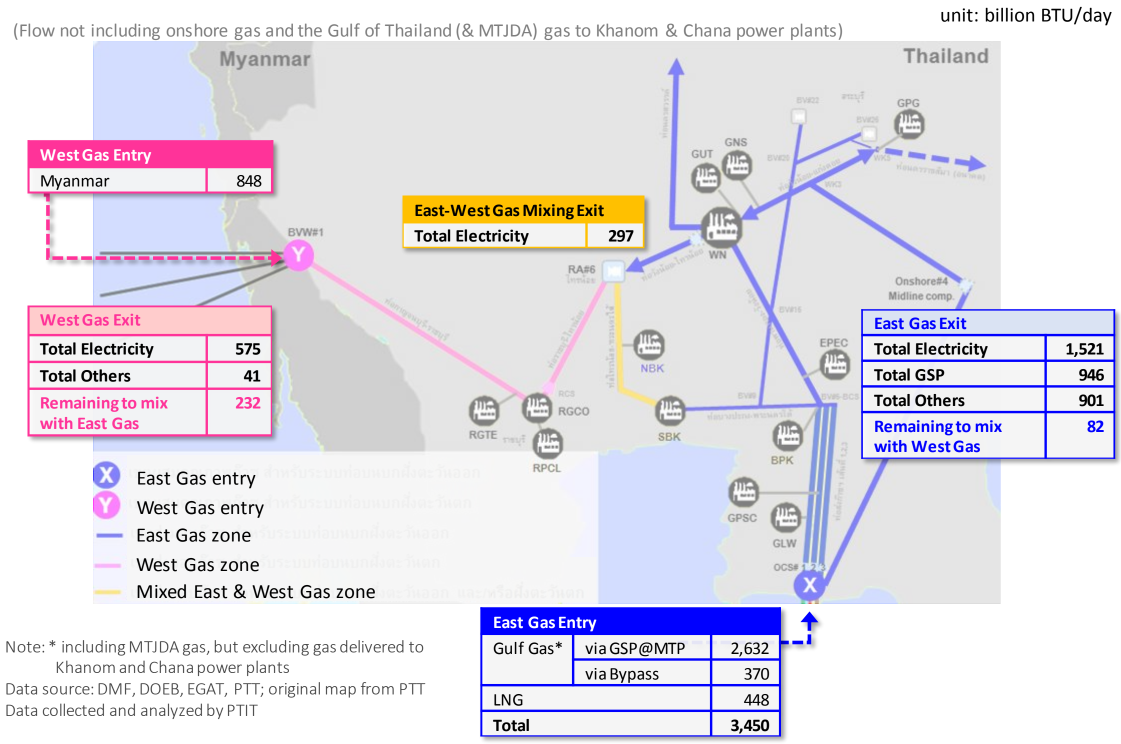
Note: * including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants
Data source: DMF, DOEB, EGAT, PTT; original map from PTT
Data collected and analyzed by PTIT

BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.16. Main Natural Gas Flow in Thailand: Scenario B – Day 48–180

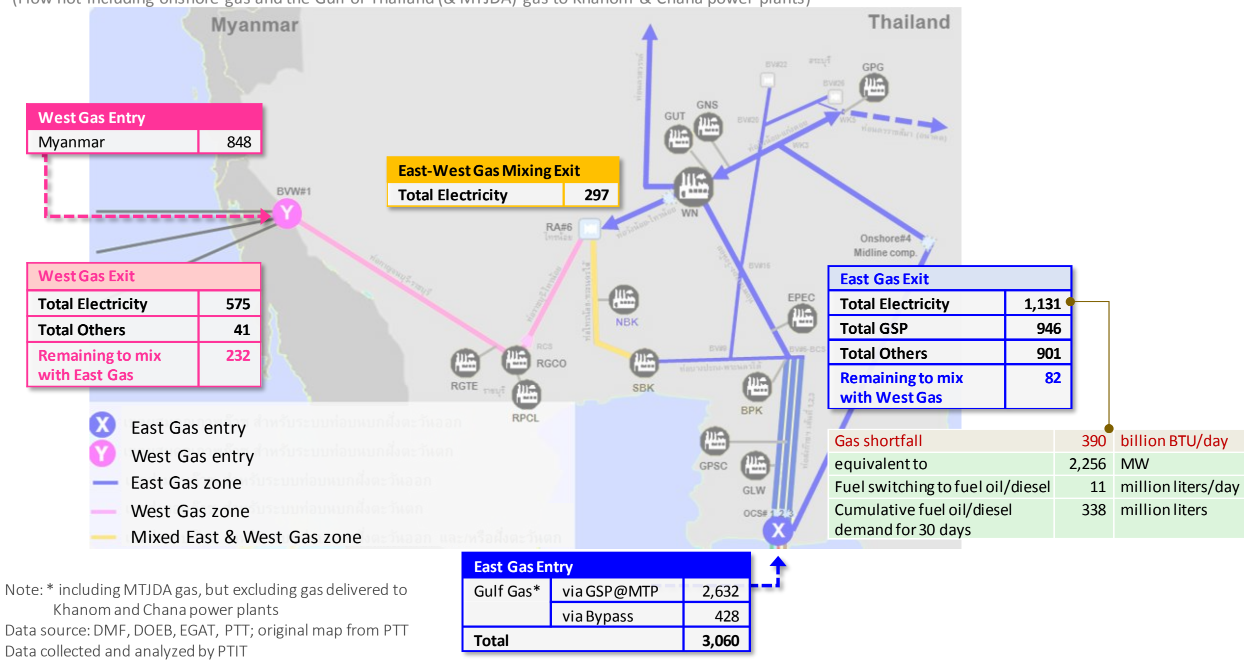


BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant
Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.
Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.17. Main Natural Gas Flow in Thailand: Scenario C

unit: billion BTU/day

(Flow not including onshore gas and the Gulf of Thailand (& MTJDA) gas to Khanom & Chana power plants)

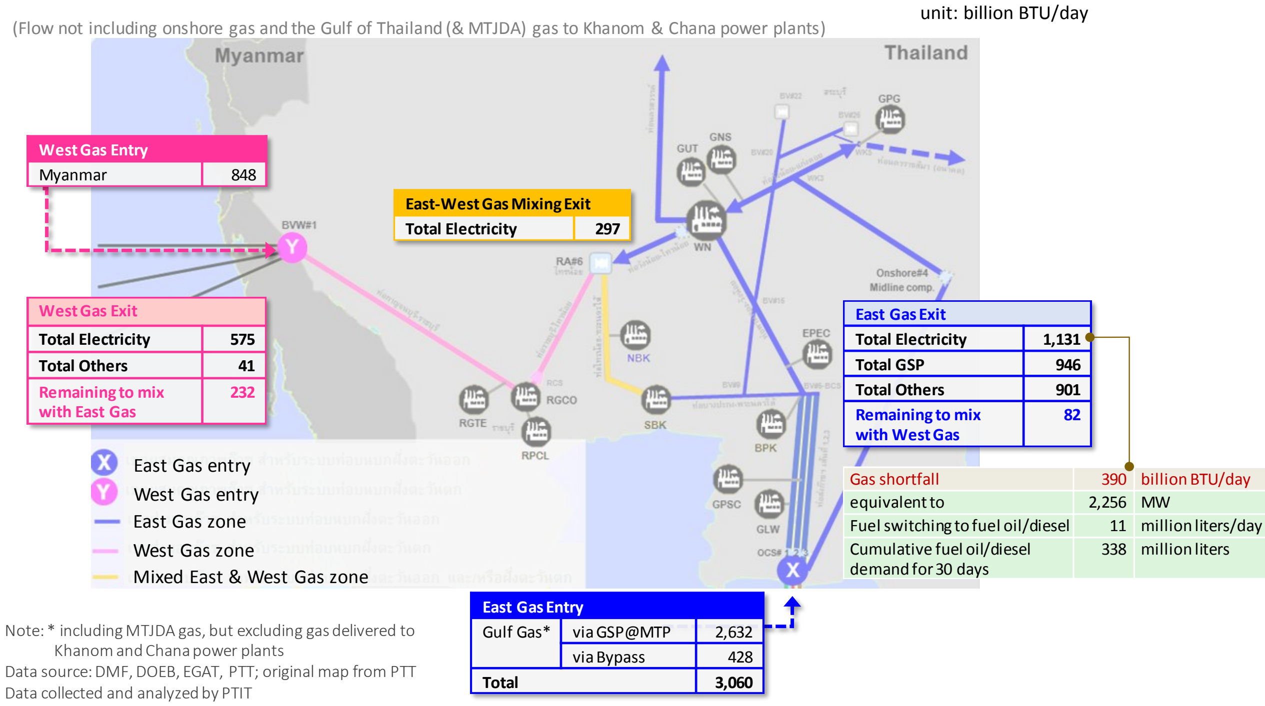


BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.18. Main Natural Gas Flow in Thailand: Scenario D – Day 1–30

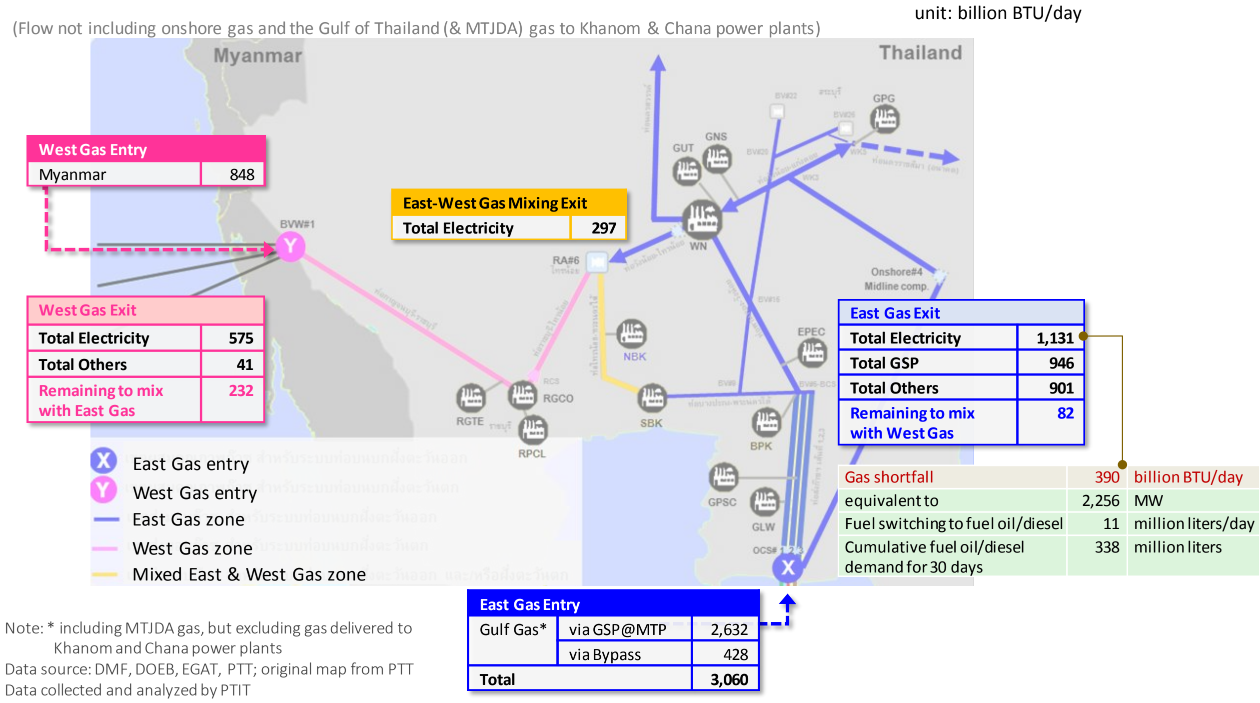


BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

Figure 3.19. Main Natural Gas Flow in Thailand: Scenario D – Day 31–180



BPK = Bang Pakong power plant, BTU = British thermal unit, BVW #1 = Block Valve West #1, EPEC = Eastern Power and Electric power plant, GLW = Glow IPP power plant, GNS = Gulf JP Nong Saeng district power plant, GPG = Gulf Power Generation power plant, GPSC = Global Power Synergy power plant, GSP = gas separation unit, GUT = Gulf JP Uthai district power plant, LNG = liquefied natural gas, MTJDA = Malaysia–Thailand Joint Development Area, MTP = Map Ta Phut, NBK = North Bangkok power plant, OCS #1,2,3 = Onshore Compressor Station #1, 2, 3, RA #6 = Ratchaburi-Wangnoi #6 Block Valve Station, RGCO = Ratchaburi Electricity Generating Co, Ltd power plant, RGTE = Ratchaburi Tri Energy Co, Ltd power plant, RPCL = Ratchaburi Power Co, Ltd power plant, SBK = South Bangkok power plant, WN = Wang Noi power plant

Note: Including MTJDA gas, but excluding gas delivered to Khanom and Chana power plants.

Source: Department of Mineral Fuels, Department of Energy Business, Electricity Generating Authority of Thailand, PTT; original map from PTT; data collected and analysed by the Petroleum Institute of Thailand.

3.4 Appendix

Main Assumptions and Conversion Factors Used in Chapter 3

Natural gas supply and demand volume			@	1,000	BTU/scf
	5	mmtpa LNG	=	700	mmscfd natural gas
			=	700	billion BTU/day natural gas
To generate electricity				use	
	700	MW		121	mmscfd natural gas
				121	billion BTU/day natural gas
	100	MW		0.5	million litres/day fuel oil
	100	MW		0.5	million litres/day diesel
	158.984	litres	=	1	barrel
NGV	0.128	kg	=	1	litre
LPG	0.54	kg	=	1	litre
	1	MJ	=	0.000947817	million BTU
Heating value	NGV		=	38,500	BTU/kg
	NGV		=	5.2	MJ/litre
	gasoline		=	33.5	MJ/litre

BTU = British thermal unit, kg = kilogram, LNG = liquefied natural gas, LPG = liquefied petroleum gas, MJ = megajoule, mmscfd = million standard cubic feet per day, mmtpa = million metric tonnes per annum, MW = megawatt, NGV = natural gas for vehicles.
Source: Petroleum Institute of Thailand.

Chapter 4

Policy Recommendations

The case study shown in Chapter 3 has given insight into Thailand's resilience against LNG import disruptions, which is applicable to a number of other emerging EAS countries introducing LNG. Emerging EAS countries introducing LNG are recommended to consider risks associated with LNG import disruption and their countermeasures. Similar case studies are recommended for respective EAS emerging countries to discuss country-specific energy policy. While each country has its own energy policy suitable for its energy system, some common recommendations can be derived to enhance the resilience against LNG import disruptions.

4.1 Identify critical risk sources for LNG import disruption

Unexpected disruption of LNG import may occur at any process in the LNG supply chain, such as gas production, liquefaction, LNG transport, and LNG receiving and regasifying, either due to political, commercial, technical, or environmental reasons. This should be carefully examined. Since the LNG market is expanding globally, risk sources associated with LNG trade are rather common for LNG importing countries. One critical risk is the disruption of export, either politically or physically. It becomes most critical if the export disruption is from the largest long-term contract. The impact could be even more extreme for countries that have just started importing LNG, because those countries are more likely to rely on a single long-term LNG contract, or if any a few, for most of their LNG procurement.

Another critical risk is related to failure of an LNG receiving terminal, either technically or by natural disaster. LNG receiving could be a bottleneck of the entire LNG supply chain, if a country has just one receiving terminal. Disruption of LNG export and failure of LNG receiving terminals could be the two most critical risk sources for countries that have just introduced LNG import. The severity of such critical situations could be eased through increasing LNG imports, thereby allowing these bottlenecks to be diversified. A set of LNG import disruption scenarios should be formulated, where the amount and duration of disruption are specified. It should be stressed that disruption scenarios must include unprecedented worst-case scenarios, which individual energy industry players may not be able to solve, but which the government should deal with as a matter of national energy security.

4.2 Evaluate the impact of LNG import disruption on energy supply system and identify countermeasures

The impact of an LNG import disruption could spread to a country's entire energy system. Detailed information on a country's energy system is essential to investigate the impact and relevant countermeasures. Information on an energy system should include not only 'actual flow' but also 'available capacity' of each element in the energy system that could be utilised as back-ups for countermeasures. Necessary information on available capacity includes:

- Indigenous production of gas, oil and coal if any
- Gas process facilities and oil refineries including flexibility of the process
- Power generation by fuel type including fuel switch capability
- Transmission of electricity grid and gas pipelines, domestic and/or interconnected.
- Energy demand portfolio, usage-wise with peak and average demand.

For the demand side, values for peak as well as average demand for electricity and gas are needed to secure energy supply during the peak demand period. Information related to sale and purchase agreements among power producers, grid operators, retailers and consumers would also help in identifying and prioritising viable countermeasures. An energy flow analysis in the event of an LNG import disruption should then be conducted to investigate whether the entire energy supply in a country could be secured. Necessary countermeasures should be identified, which are either viable or to be planned in future energy policy.

The case study for Thailand shows that detailed information on the country's energy supply system greatly helps evaluate viable countermeasures. With its in-depth information and systematic analysis, the case study shows that in the present situation Thailand is reasonably resilient against LNG import disruptions. Thailand has its own indigenous gas resources, of which production can be increased to some extent to supplement the shortage of LNG. Furthermore, the country has plenty of bi-fuel power generation capacity, ready to be switched from gas to oil. Thailand also has a redundant transmission system for both electricity and gas, which could allow it to manage supply of electricity and gas. The results show that unless the LNG import disruption is large and lasts for a long period, Thailand could successfully secure its country's energy supply.

4.3 Generate long-term energy supply plan that incorporates countermeasures for import disruption of LNG and other energy sources

The case study for Thailand is based on current LNG imports to Thailand, which constitutes 21% of total natural gas supply at maximum. Thailand's indigenous natural gas production is much larger than the amount of imported LNG in the current LNG-introduction phase, allowing Thailand to supplement disrupted LNG by increasing indigenous gas production. On top of this, Thailand's total energy consumption is far larger than imported LNG, and primary energy sources are well diversified at present. This gives Thailand a certain flexibility to switch fuels to manage an LNG import disruption. In 10 years, however, Thailand's LNG import is projected to constitute over two-thirds of the country's natural gas supply. As LNG import increases to become more significant among the primary energy sources in the future, more efforts will be necessary to identify viable countermeasures.

Long-term and short-term energy security should be considered along with resilience against LNG import disruptions. This is more important as a country's reliance on LNG import increases.

4.5 Expected policies for the resilience against LNG import disruption

The following three categories of policies are expected to incorporate countermeasures for import disruption of LNG and other energy sources in the long-term energy supply plan.

- **Energy policy**

A diversified energy supply portfolio, in terms of fuel type and resource origin, is clearly recommended. If a country has indigenous energy resources, a balance between imported and indigenous resources should be also respected. Indigenous energy sources are in fact very reliable and indispensable, particularly when import of fuel is disrupted. Indigenous energy development should be strategically pursued. A reasonably redundant energy supply network is recommended. Transmission or transport capacity of electricity, oil, and gas should be carefully examined and designed to be redundant enough to prevent them from becoming bottlenecks in case of a disruption. As for power generation, the capability of switching fuels between oil and gas should be considered; part of power generation units should be installed to be fuel-switch ready.

Another aspect is energy efficiency. Energy efficiency should be always pursued, for which reducing peak demand for electricity and gas is particularly important.

Reform of the energy industry should take into consideration attracting investment from a variety of players. A liberalised energy market, if properly designed and implemented, would be the most resilient against energy import disruptions while reducing energy import/supply cost. An energy market with a variety of players could act in the most flexible manner in case of an energy supply disruption.

- **LNG import and natural gas supply policy**

Careful consideration of LNG procurement is recommended. When starting to import LNG, countries should diversify projects or exporting countries so as not to rely on a single country for the majority of the LNG supply. A balance between long-term procurement and spot purchases should be carefully examined.

LNG receiving terminals could be the most serious bottleneck for the entire LNG supply chain. Preferably, a country should have multiple LNG entry points or receiving terminals that are geographically diversified as well. Thailand, for example, is studying the feasibility of constructing two new LNG receiving terminals. Both terminals are along the Gulf of Thailand near the existing terminal to supply gas to the greater Bangkok area. While economically less preferable, a new terminal could be recommended along the west coast of Thailand, rather than having all the terminals concentrated along the Gulf of Thailand.

A nationwide natural gas supply network, which connects LNG receiving terminals as well, is needed to ensure a flexible and reliable supply of gas. Along with the gas pipeline network, the storage capacity of gas and/or LNG should be carefully designed.

- **Regional cooperation**

It may take a while before the global LNG market becomes as mature as the oil market. This offers possibilities for LNG importing EAS countries to cooperate in LNG procurement. Resale of LNG among importing countries could help manage disruption of LNG import. For some emerging EAS countries that are introducing LNG, working with mature LNG- importers such as Japan, the Republic of Korea, and Taiwan may be a good option. With far more LNG procurement and storage capacity, they have enough flexibility to supplement LNG shortages for emerging EAS countries in case of a supply disruption.

Unlike Europe, which has a well-established regional energy network, the EAS region has virtually no energy network. The few cross-boundary interconnections available for electricity and gas are mainly for fixed trade purposes. Although idealistic, an energy supply network across all EAS countries should be considered, including particularly the Indochina Peninsula and its surroundings. Having a regional energy network would make it easier to counteract LNG import disruptions. A regional energy network, including one on natural gas, could also help establish resilient energy system more economically with lower investment and operating costs.

A regional power/electricity transmission network is of primary importance, because the majority of LNG is currently used for power generation in emerging EAS countries. Most LNG receiving terminals in the region are built for power generation.

With economic growth, demand will increase for natural gas for industrial and other purposes. In Thailand, for example, while approximately 60% of natural gas supply is used for power generation, the rest is used for industrial, petrochemical, and transportation (NGV) purposes. More use of natural gas in commercial and residential sectors is expected to follow. With the realisation of a regional gas network, the locations and capacity of LNG terminals could be optimised in view of economics as well as resilience against LNG disruption. Total costs including capital expenditure (capex) and operations and maintenance (O&M) could be much lower, while maintaining the same level of resilience or supply security for each country.