Myanmar: Technical Assistance on Liquefied Natural Gas Options for Myanmar Phase 1 (Selection # 1216215)

Final Report: Markets and Swaps (Revised June 2017)

22nd June2017

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Document Control			
Version	*Date*	*Prepared by*	*Reviewed by*
Draft V.01	13/12/2016	W Derbyshire	
VF (Revised June 2017)	22/06/2017	M. Madden	P. Cassar

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Abbreviations and acronyms

Abbreviation	Description
bbl	Barrels of oil
Bcm	Billion cubic metres
Btu	British thermal units
C&F	Cost and freight
cm	Cubic metres
EMP	Energy master plan
FSRU	Floating storage and regasification unit
FY	Financial Year
GoM	Government of Myanmar
GSA	Gas sales agreement
GW	Gigawatt (1,000 megawatt)
IPP	Independent power producer
JICA	Japan International Cooperation Agency
LNG	Liquefied Natural Gas
METI	Ministry of Economy, Trade and Industry (Japan)
mmbbl	Million barrels
mmbtu	Million British thermal units
mmcfd	Million cubic feet per day
mmscfd	Million standard cubic feet per day
MOGE	Myanmar Oil and Gas Enterprise
MT	Million tonnes
MTpa	Million tonnes per annum
MW	Megawatt (1,000 kilowatt)
PMP	Power master plan
PSO	Pakistan State Oil Corporation
RLNG	Regasified LNG
scf	Standard cubic feet
SNGPL	Sui Northern Gas Pipelines Limited
SSGC	Sui Southern Gas Corporation
Tcf	Trillion cubic feet

ToR	Terms of Reference
tpa	Tonnes per annum
TPA	Third Party Access

Executive Summary

Introduction

This report is submitted to the World Bank under the project *Technical Assistance on Liquefied Natural Gas Import Options for Myanmar Phase 1* (Ref:1216215). This report relates to Task 1(c) which comprises an overview of the liquefied natural gas (LNG) markets that Myanmar may access and an assessment of the potential for physical swaps of LNG with gas export partners. The project also includes two other tasks which are contained in a separate, accompanying report. These are: Task 1(a) – analysis of potential locations for LNG import facilities in Myanmar; and Task 1(b) – development of a prioritisation framework and accompanying analytical tool for selecting LNG import options and locations.

There are three main sections to this report, in addition to the introduction. These cover a description of LNG markets which Myanmar may access, a review of forecasts for LNG import requirements and an assessment of the potential to conduct LNG for pipeline gas swaps.

LNG markets and contracting models

Procurement of LNG is becoming increasingly flexible with the advent of leased FSRUs and proliferation of spot and short-term contracts. This offers significant benefits to new importers who are unable or unwilling to commit to long-term take-or-pay obligations for large LNG volumes. Such is likely to be the case in Myanmar at the beginning of imports given the uncertainties surrounding the volumes required.

The examples of Pakistan and Jordan have been used to show how this flexibility can be used. In Pakistan, the procurement of a Floating Storage and Regasification Unit (FSRU) and of LNG have been separated to better manage the credit risks involved in the latter. The FSRU is remunerated under a tolling arrangement where the terminal owner is paid for regasification of delivered LNG on a take-or-pay basis, giving them protection against procurement risks that FSRU providers are not necessarily well-placed to manage. Imports started with spot cargoes and have now extended to a five-year contract with flexibility over timing of deliveries alongside a 15-year traditional contract arrangement. In Jordan, prospective LNG suppliers enter into a master sales agreement with the power company, which then conducts tenders for small numbers of cargoes on an as-required basis under the terms and conditions in this master agreement. This preserves flexibility as regards quantities to be procured while avoiding the time-consuming need to negotiate new contracts each time a procurement is made.

Myanmar's LNG import requirements

Four different studies, issued between 2014 and 2016, have been consulted. These are:

- **JICA PMP 2014**. [JICA (December 2014), *Formulation of the National Electricity Master Plan*, Final Report: Summary].
- **EMP 2015**. [IES and MMIC (December 2015), *Myanmar Energy Master Plan*].
- **METI 2016**. [METI (February 2016), *Gas Value Chain*].

- **e.Gen 2016**. [e.Gen (July 2016), *Study on Economic Costs of Natural Gas for Myanmar Domestic Market*, Draft Final Report].

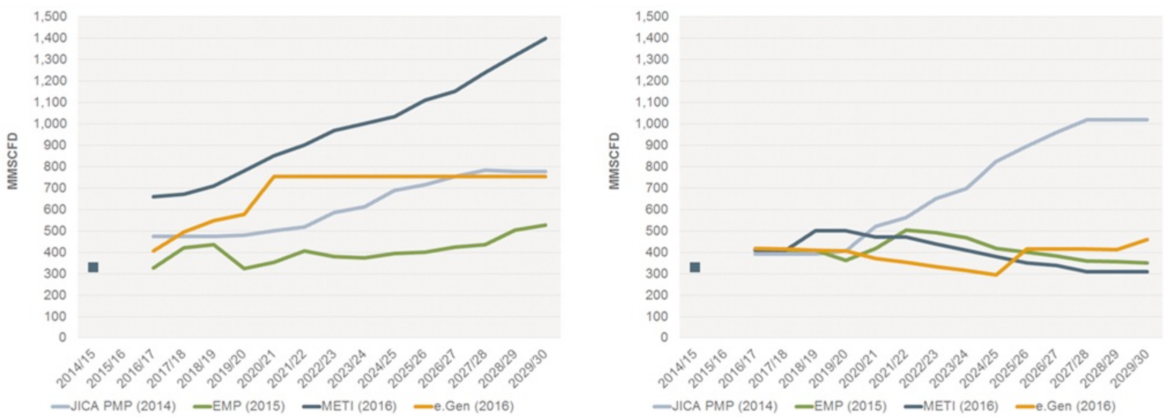
The four forecasts differ greatly in their expectations for future gas demand driven, in particular, by differences in assumptions as to the future demand for gas from the power sector. The EMP 2015 expects installed gas-fired generating capacity to increase only slightly from its 2014/15 level of 1.4 GW to 1.7 GW by 2020 with lower cost coal-fired and hydropower generating capacity being developed thereafter. The e.Gen 2016 study expected a much larger increase to 3.5 GW by 2020 but with no additions thereafter as coal-fired and hydro capacity is developed. The JICA PMP 2014 and METI 2016 study both expect continuing additions of gas-fired capacity which reaches 4.6 to 4.8 GW by 2030. However, the METI 2016 study expects much greater reliance on gas-fired generation to meet demand given an assumed slower expansion of coal-fired and hydropower capacity.

The supply forecasts contained in the EMP 2015, METI 2016 and e.Gen 2016 studies are similar, all showing declining domestic supply as production falls from the Yadana field post-2020. The exception is the JICA PMP 2014 which expects production coming on-stream from new fields to substitute for declines from existing fields.

The demand and supply forecasts across the studies are compared below.

Figure 1 Demand and domestic supply of gas, 2015-30

Demand | **Domestic supply**



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016. Note the forecasts are shown in mmscfd. Projected supplies from different sources are adjusted accordingly to allow for differences in heating values.

These very different forecasts are reflected in the uncertainty around LNG import requirements:

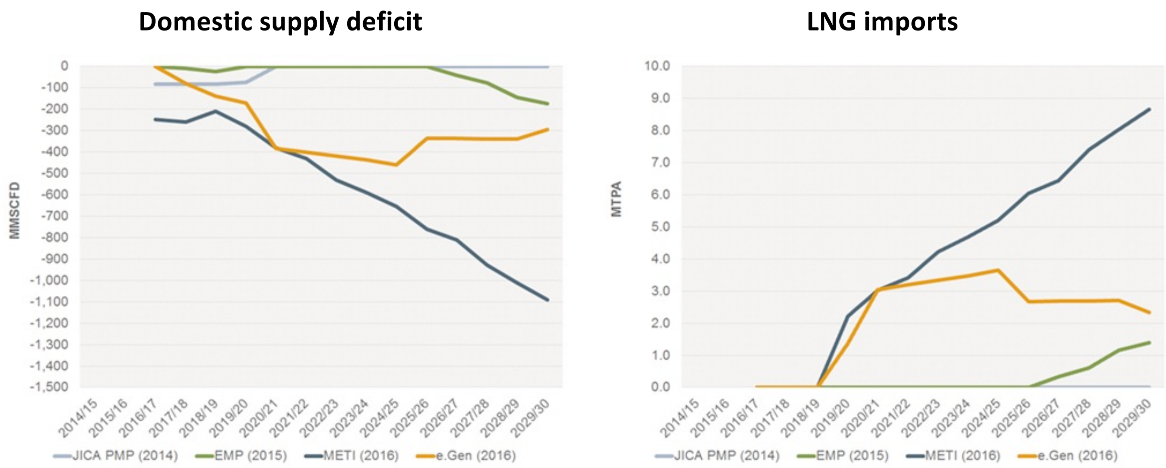
- At one extreme, using the forecasts in JICA PMP 2014, there is no requirement for imports at all over the period to 2030.

- At the other extreme, using the METI 2016 forecasts, requirements for LNG imports start at 2.2 MTpa in 2020 and rise continually to reach 8.7 MTpa by 2030.

- The EMP 2015 forecasts imply a requirement for LNG imports starting at very low volumes in 2027 and reaching only 1.4 MTpa in 2030.

- Lastly, the most recent forecasts in e.Gen 2016 would imply LNG imports starting in 2020 at 1.4 MTpa, peaking in 2025 at 3.7 MTpa and then declining again to 2.3 MTpa in 2030.

Figure 2 Supply deficit and LNG import requirements, 2015-30



Source: Consultant calculations. LNG import estimates assume that these can only begin from 2019.

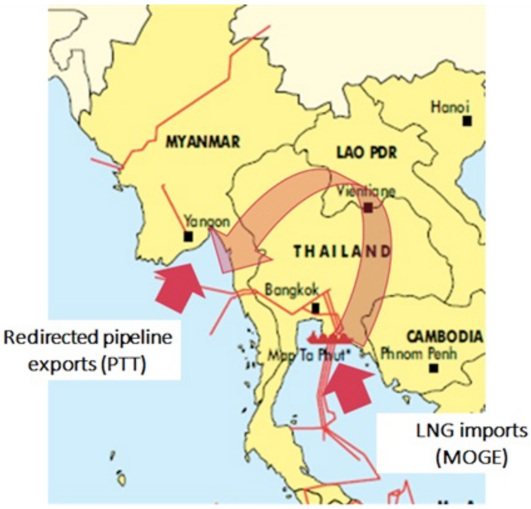
Review of potential gas swaps

All four forecasts reviewed expect to see a small supply deficit during the period to 2019/20 when a new LNG import terminal might commission. Among the proposals for addressing this has been that of gas swaps, under which Myanmar would substitute LNG for pipeline gas exports, thus freeing export gas to supply the domestic market. As additional gas will need to be supplied to the Yangon area this requires diverting exports to Thailand given the lack of links from the Shwe export pipeline.

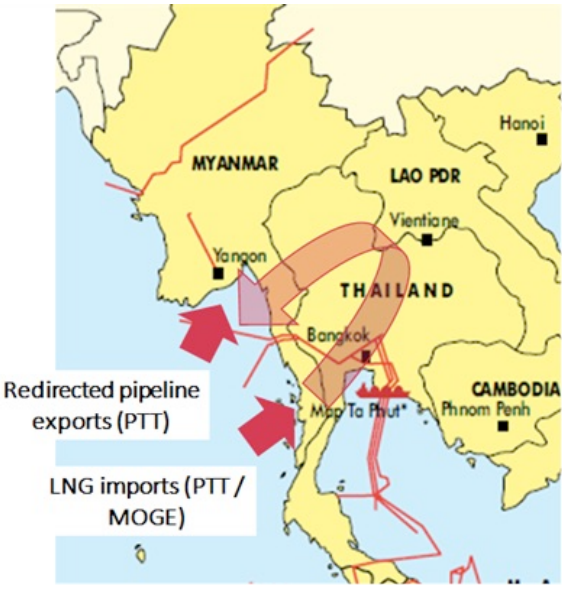
Separately, proposals have been made for Myanmar, in the medium-term, to procure additional LNG cargoes to be delivered to the LNG import terminal proposed by PTT for future supply to Thailand. These cargoes would be used to substitute for gas that would otherwise have been exported from Yadana, allowing this to be redirected to domestic supply. These two possible swap arrangements are shown below.

Figure 3 Illustrative gas swaps arrangement

Short-term (to 2019/20)



Medium-term



Our assessment is that a short-term swap arrangement is infeasible:

- It is unlikely that Myanmar Oil and Gas Enterprise (MOGE) can guarantee reliable supplies of LNG, leaving PTT at risk of interruptions.
- Physical constraints on PTT's gas transmission system mean that LNG delivered into Map Tha Phut cannot readily be transported to the Ratchaburi power complex which currently receives pipeline gas from Myanmar.
- Physical constraints on MOGE's gas transmission system means that the maximum increase in firm gas supplies that could be released by a swaps arrangement would be only around 50 mmcfd (equivalent to 35 mmscfd).

Overall, we conclude that short-term swaps are unlikely to be accepted by PTT and would be unlikely to release significant additional quantities of natural gas to the Myanmar market. However, even if the constraints on the Thai side were lifted, Myanmar would still need to overcome infrastructure and capacity issues.

Medium-term swaps using a PTT-developed LNG import terminal located in Myanmar would have much reduced commercial and legal difficulties relative to short-term swaps. Again, they would only be of value if, by maintaining existing volumes supplied through the Yadana to Yangon pipeline, they avoid the need for new investments in pipeline capacity elsewhere. If this is not the case then such swaps would simply substitute LNG imports into the proposed new terminal for imports into a PTT-developed terminal.

1 Introduction

This report is submitted to the World Bank under the project *Technical Assistance on Liquefied Natural Gas Import Options for Myanmar Phase 1* (Ref:1216215). The project comprises three tasks:

- Task 1(a) – Siting analysis to assess potential locations of liquefied natural gas (LNG) import facilities in Myanmar.
- Task 1(b) – Prioritisation framework and accompanying analytical tool for LNG import options and locations.
- Task 1(c) – Overview of the LNG markets that Myanmar may access and an assessment of the potential for physical swaps of LNG with gas export partners.

This report covers Task 1(c). The other identified tasks are covered in a separate, accompanying report. It is structured as follows:

- **Section 2 - LNG markets and contracting models** provides an overview of LNG markets and examples of LNG procurement strategies under conditions of uncertainty as apply in Myanmar.
- **Section 3 - Myanmar's LNG import requirements** reviews forecasts of demand for and domestic supply of natural gas in Myanmar and, from this, the implied LNG import requirements to 2030.
- **Section 4 - Review of potential gas swaps** assesses the feasibility of conducting LNG for piped export gas swaps, as a way of redirecting an increased share of Myanmar's gas production to the domestic market.

2 LNG markets and contracting models

2.1 Introduction

In this section, we provide an overview of the global LNG market, recent developments leading to greater flexibility in procurement and examples of how other countries have used this increased flexibility to begin importing LNG. The intent is not to recommend on a particular procurement strategy for Myanmar but to raise awareness of the opportunities to increase flexibility which, as we discuss in the following section, can be expected to be of major importance given current uncertainties over LNG needs in Myanmar.

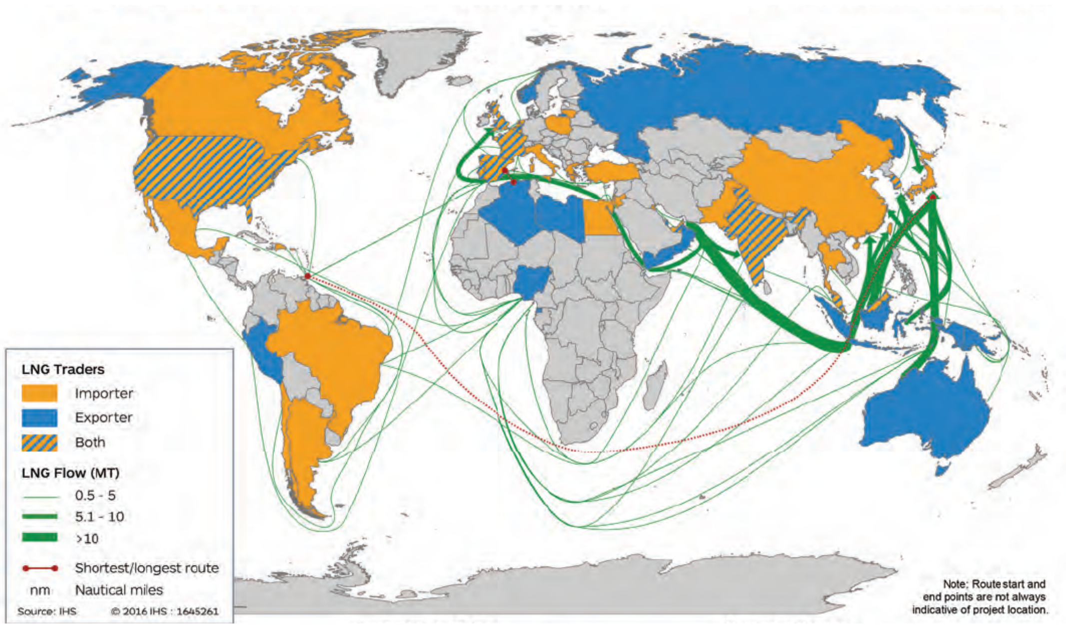
2.2 The global LNG market

2.2.1 Trade flows

In 2015, LNG represented 32% of global gas exports and 10% of global gas consumption. The market has expanded rapidly, with global trade volumes reaching 245 MT in 2015, up from 100 MT in 2000. The largest volume of trades has been within the Pacific Basin. While this remains the case, its share is falling (down to 39% in 2015) as European countries shift from pipeline imports, domestic production falls and LNG prices decline making it more competitive (see discussion below). The emergence of Qatar as the dominant LNG supplier has also contributed to this given its pivotal location between the Asian and Atlantic Basins.

Trade flows in 2015 are shown in Figure 4, below.

Figure 4 LNG trade flows, 2015



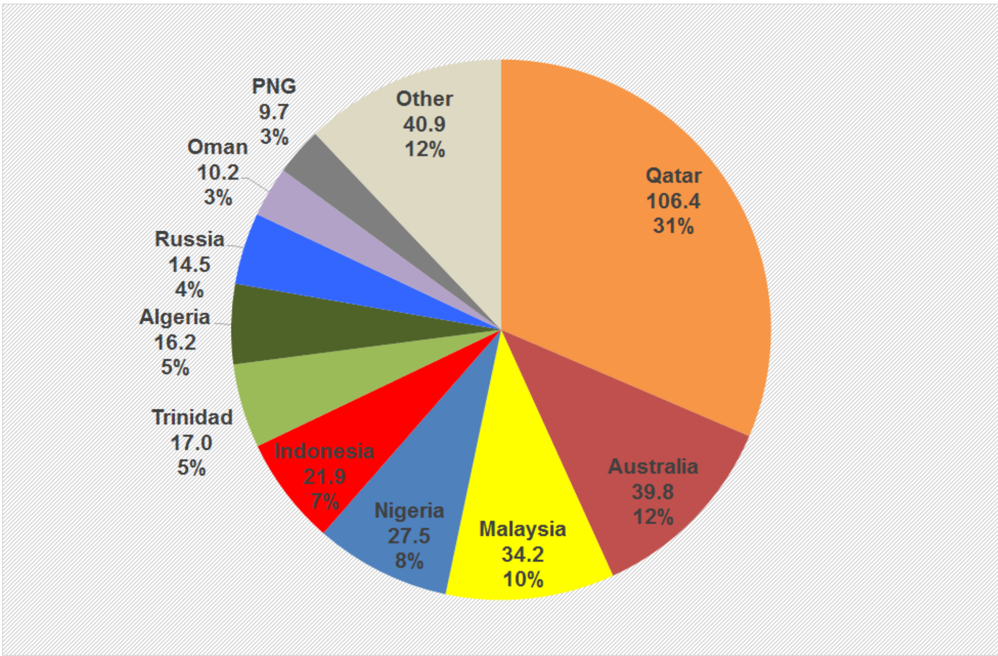
Source: IGU (2016), *World Gas LNG Report*[1]

[1] *Available at: http://www.igu.org/publications/2016-world-lng-report*

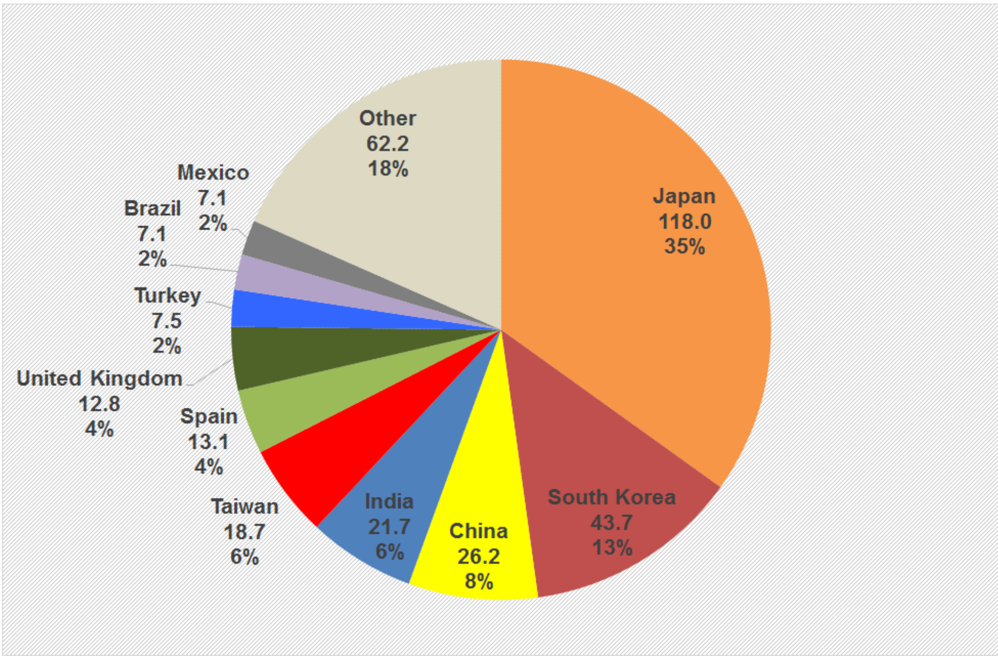
As of 2015, 17 countries exported and 33 countries imported LNG. Four countries began imports in 2015 (Egypt, Jordan, Pakistan and Poland). In recent years, Qatar has come to dominate LNG exports but Australia is rapidly adding capacity and saw the fastest export growth in 2015 (up 6.1 MTpa or 8.3 Bcm in the year). Imports continue to be dominated by Japan and South Korea, which are heavily dependent on LNG for power generation and even more so in the aftermath of the closures of nuclear power plants following the Fukushima incident. Together, these two countries represent around one-half of total demand. However, European markets have grown significantly with the United Kingdom and Spain together representing almost 10% of total imports in 2015.

Figure 5 LNG exports and imports by country, 2015 (Bcm)

EXPORTS



IMPORTS



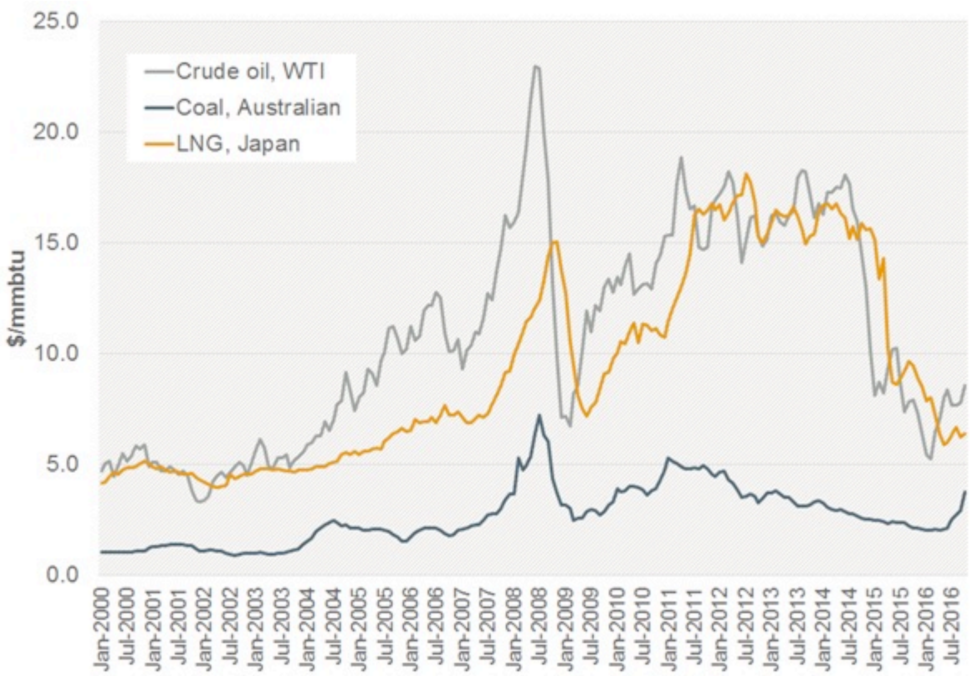
Source: BP Statistical Review 2016[2]. To convert from Bcm to MTpa, divide by 1.36.

2.2.2 Prices

Around 75% of LNG volumes use oil-indexed pricing. Unsurprisingly, the post-2014 declines in oil prices have been reflected in LNG prices. The close correlation between oil and LNG prices is shown below. Also noticeable is that, while LNG prices have historically been below oil-equivalent levels, the two converged post-2012 in Japan in response to the jump in demand caused by the shutdown of nuclear power plants.

[2] *Available at: http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy/downloads.html*

Figure 6 Japan LNG, crude oil and coal prices, 2000-16

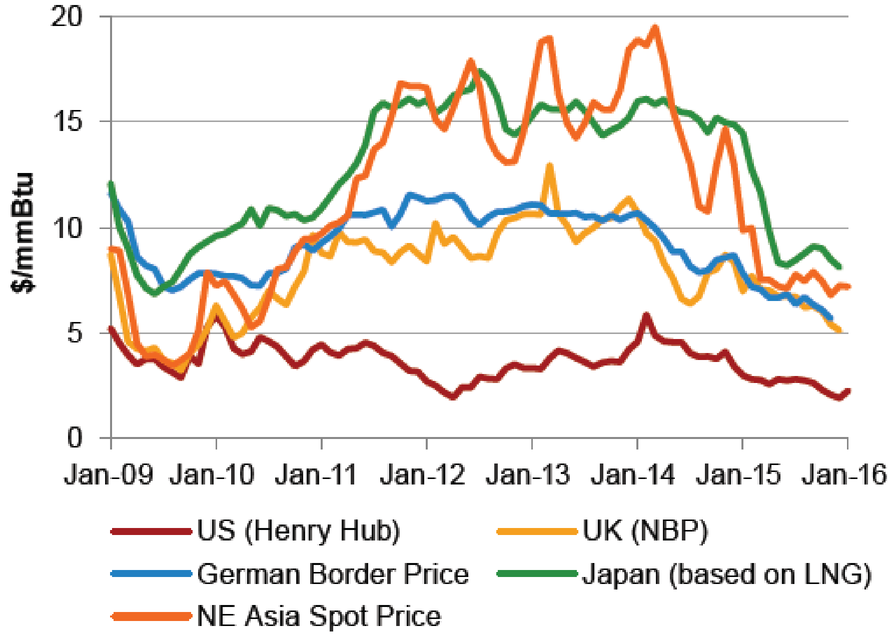


Source: World Bank Commodities Prices[3]

Historically, the LNG market has been split into the Atlantic Basin and Pacific Basin markets with the former market seeing competition against pipeline gas while the latter market has lacked such competition. As a result, an Asian price premium has generally been observed with buyers willing to pay higher LNG costs to ensure supply security in the absence of alternatives. The declining share of oil-indexed pricing in European markets, which is now below 40% in Europe in response to pressures from gas-on-gas competition, has also contributed to the differentials in prices across the markets. The magnitude of these historic differences can be seen below.

[3] *Available at: http://www.worldbank.org/en/research/commodity-markets*

Figure 7 Gas prices by region, 2009-15 (monthly averages)



Source: IGU (2016), *World Gas LNG Report*

These differences are expected to narrow in future years as Asian buyers increasingly look to purchase on bases other than oil indexation (such as Henry Hub-plus prices) and as arbitrage between the two markets grows with short-term trades. Japan, China and Singapore are also all trying to develop LNG hubs where prices will be set by spot market competition between different suppliers. However, the fall in oil prices and consequent decline in oil-indexed LNG prices has already eradicated much of the price differences across markets. This can be seen in Figure 8, below, which shows landed prices for a number of major importers in October 2016.

Figure 8 Landed LNG prices by market, October 2016

Source: Federal Energy Regulatory Commission[4]

2.2.3 Future developments

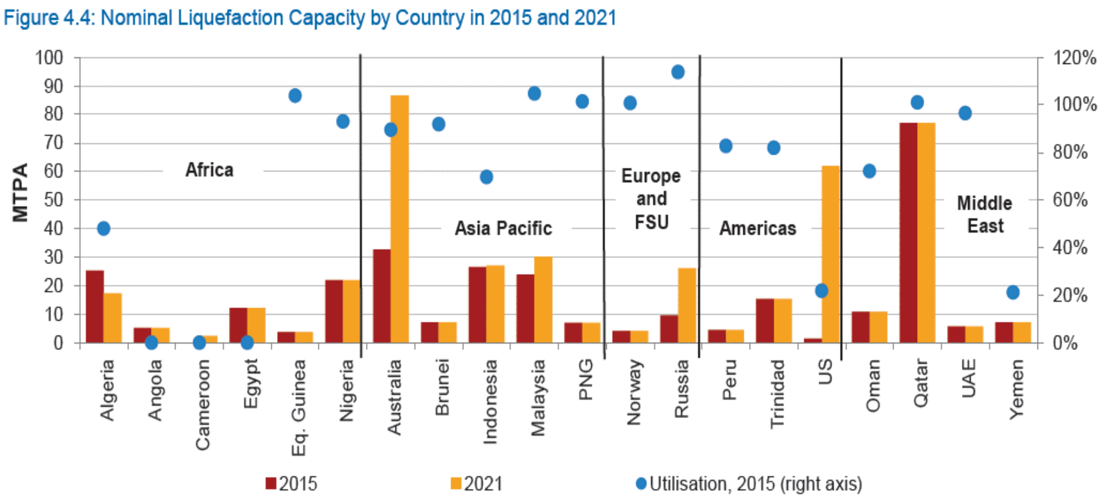
In the short to medium-term, expectations are for further increases in LNG supply while demand remains relatively flat. Within Europe, a combination of economic slowdown and competition from lower-cost coal and renewables has led to stagnant gas demand. Within Asia, Japan and South Korea's post-Fukushima demand increases are now being rolled back while China is also seeing relatively flat demand as the economy slows and electricity demand growth, in particular, falls.

At the same time, large additional export capacities are coming online, many of which were committed during the recent years of high LNG prices and, in the USA, the shale gas production boom. Figure 9 shows nominal liquefaction capacity in 2015 and projected for 2021. Global capacity is expected to grow by 142 MTpa (equivalent to almost 50% of current capacity of 301.5 MTpa) by 2021 with the biggest contributions being as follows:

- Australia: 6 projects totalling 54 MTpa by 2018
- USA (Gulf and East Coast): 5 projects totalling 62 MTpa by 2019
- Russia: Yamal LNG of 17 MTpa by 2019

[4] *Available at: https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf*

Figure 9 Liquefaction capacity, 2015 and 2021

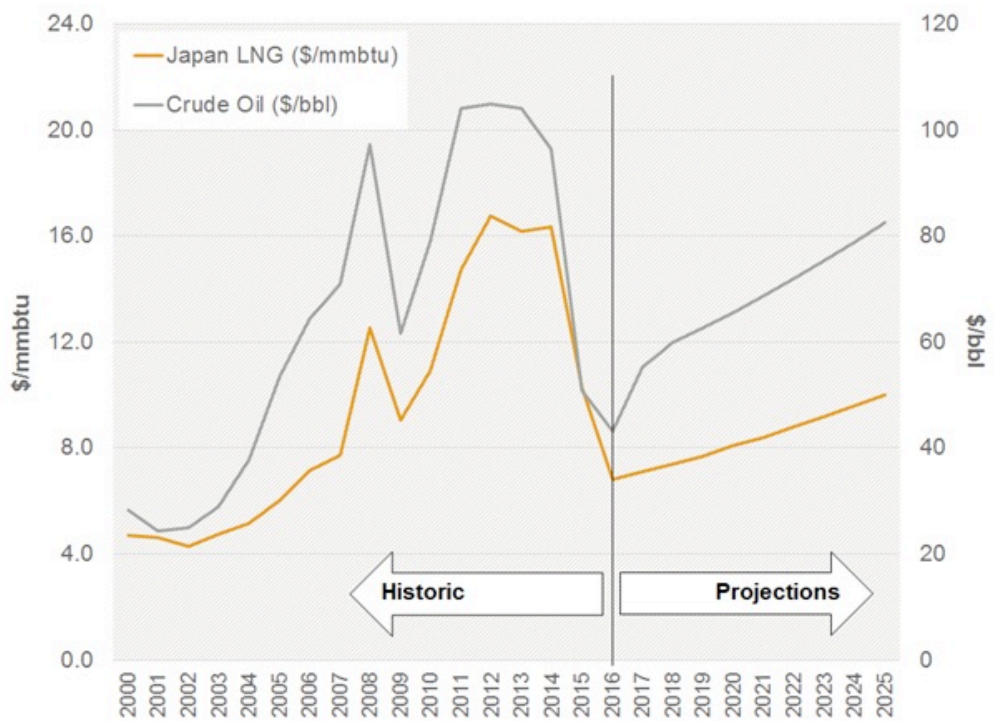


Source: IGU (2016), *World Gas LNG Report*

The combination of flat demand and large expansion of supply means over-supply seems likely. Consequently, prices are not expected to increase substantially before 2020.

Figure 10 shows historic and World Bank projections for crude oil (in $/bbl) and Japanese LNG prices. Projections are for LNG prices to rise from an estimated average in 2016 of $6.8/mmbtu to $8.1/mmbtu in 2020 and $10.0/mmbtu in 2025. However, these increases lag behind projected increases in crude oil prices. Over the 10 years to 2025, LNG prices are projected to increase by around 50% while crude oil price increase by 90%.

Figure 10 Historic and projected oil and LNG prices, 2000-25 (World Bank)



Source: World Bank Commodities Prices

2.3 LNG procurement models

2.3.1 Traditional contracting

LNG investments are large and capital-intensive, creating major risks for the seller if it cannot find a buyer for its output. Traditionally, these risks were managed by long-term (20+ years) contracts between buyer and seller with take-or-pay requirements on the buyer. In return, the buyer is offered security of supply.

Price risks are shared between seller and buyer through oil-indexation. The buyer shares in the upside as oil prices rise while the seller is assured that gas will remain competitive against oil. To ensure both parties can share in any rents resulting from differences between LNG prices in different markets, contract volumes cannot be diverted by the buyer to other markets without the assent of the seller.

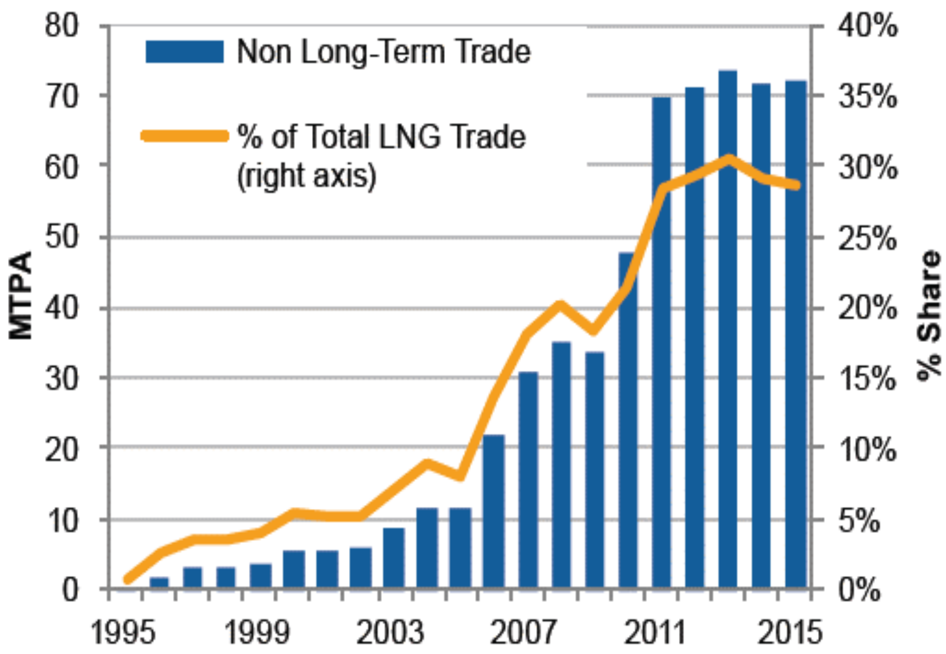
2.3.2 Short-term and spot contracting

This traditional contracting model is changing. The shift to prices being set through gas-on-gas competition in Europe and moves towards this in Asia have already been noted above. The market is also seeing increasing shares of trade under short-term (less than two-year) and spot arrangements. These changes are being driven by an interlocking set of factors, including:

- Increased flexibility in LNG importing as a consequence of unbundling (see below).
- Increased competition in buying gas markets as these are liberalised, making buyers unwilling to commit to long-term contracts which may become stranded.
- Legal interventions in the EU which have forced the removal of destination restrictions, allowing LNG buyers to redirect cargoes to other markets.
- New supplies coming onto the market which are not contracted long-term, either willingly or because over-supply has led to a lack of buyers.
- Reduced demand for LNG in traditional markets due to slowing economic growth and loss of competitiveness against other fuels, notably coal.
- Increased price differences between markets in recent years.
- The growth of portfolio traders of gas who do not own facilities but look to arbitrage price differences.

The extent of the changes can be seen below. In 2000, only around 5 MTpa representing 5% of the total market was traded on a non-long term basis (contracts of less than five years). By 2013, this has risen to 70 MTpa and around 30% of the market. While volumes and shares have declined slightly since then, they still represent more than a quarter of total trades. Most of this is represented by short-term trades (under two years) which comprised 66 MT or 26% of all trades in 2015.

Figure 11 Growth in non-long term trades, 1995-2015



Source: IGU (2016), *World Gas LNG Report*

In 2014, the split of spot and short-term trades was as follows:

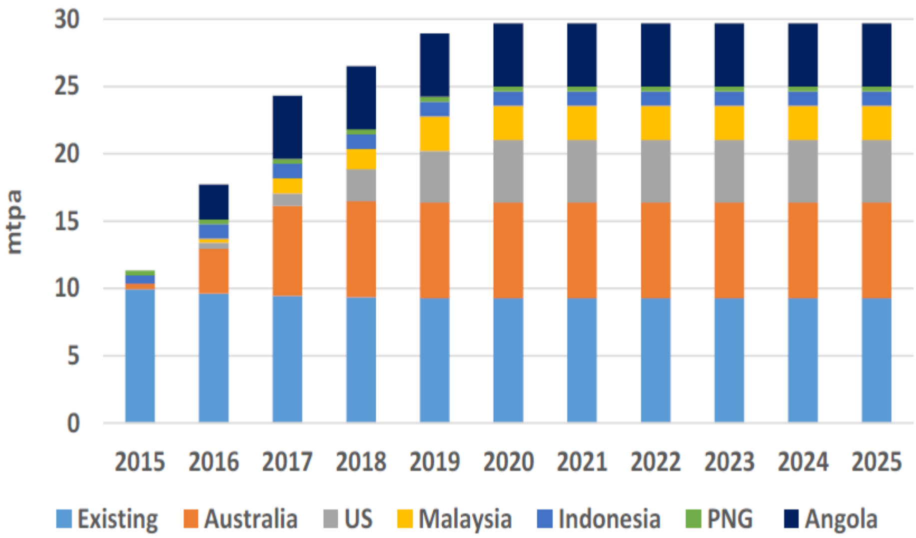
- Sales by portfolio traders: 28 MT (41% of spot and short-term trades)
- Sales by QatarGas of uncommitted gas (without long-term contracts): 25 MT (36%)
- Sales by other producers of uncommitted gas: 10 MT (14%)
- Re-exports[5]: 6 MT (9%)

Portfolio traders include a number of major gas companies such as BP, Shell (ex-BG), ENI, Enel, Engie, ExxonMobil, Gas Natural, Gazprom, Iberdrola, Pavilion, Total. There are also a number of commodity-trading companies (that do not own production facilities) including Trafigura, Gunvor, Glencore and Vitol.

Looking ahead, volumes of uncommitted or available LNG supplies are likely to rise. From 11 MT in 2015 (excluding sales by Qatar), they are projected to increase to 30 MT by 2020 and, thereafter, remain at similar levels. This is driven by new Australian and US supply not committed to specific markets and, noticeably, by new Angolan supplies. The growth represents a combination of gas sellers being willing to take on market risk and gas buyers being unwilling to sign new long-term contracts. Short-term trading volumes are likely to rise alongside this growth in uncommitted supply.

[5] *Re-exports are where a cargo is unloaded, stored and then reloaded for delivery to a third country. This may be to take advantage of market price movements. It may also be used as a way of bypassing contractual restrictions on redirecting LNG cargoes ('destination clauses').*

Figure 12 Estimated uncommitted LNG supply, 2015-25



Source: Corbeau A and D Ledesma (2016), *LNG Markets in Transition*[6]

2.3.3 Unbundling of activities

Increased short-term contracting has been accompanied and facilitated by the unbundling of the LNG industry. In place of vertical chains where buyers typically owned the import terminals and regasification facilities and had ownership stakes in the producing, liquefaction and shipping companies, these functions are now becoming separately owned. In part this is due to the intermediation offered by portfolio traders. However, it also represents changes in technology and, in particular, the rise of Floating Storage and Regasification Units (FSRUs). By their nature (as discussed much more extensively in the separate report on siting options), these can be readily redeployed where no longer needed and scaled-up by adding further FSRUs where demand grows. This flexibility also means that owners of FSRUs are no longer at the same level of 'holdup' risk as onshore facilities face—where these are dedicated to a single buyer and so exposed to ex-post pressures to renegotiate contracts or to becoming stranded after the investment is made.

In turn, this reduced risk and flexibility has meant that FSRUs can be leased rather than having to be purchased outright. This allows LNG importers to start up in a relatively low risk way, by leasing an FSRU for a period of time with the option of terminating the contract rather than being left with an import facility that is not required. As well as this, FSRUs offer the advantages of speed of deployment and, in general, lower costs for smaller-sized facilities compared to onshore terminals.

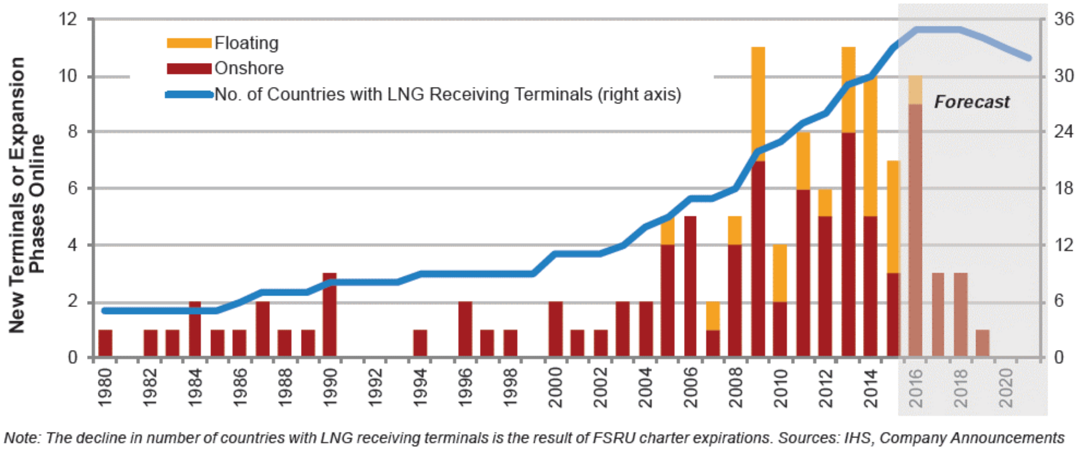
Demonstrating the way that FSRUs have become the favoured approach for new importing countries, Egypt, Jordan and Pakistan all started their LNG imports in 2015 using FSRUs. Of seven countries planning to become new LNG importers by 2017, five are using FSRUs. There are currently two FSRUs within SE Asia, both in Indonesia (Nusantara, 2012 and Lampung, 2014).

The two figures below illustrate how FSRUs have become a growing share of the market. The majority of new import terminals opened since 2013 use FSRUs. Of 33 importing countries in 2015,

[6] *Available at: https://www.kapsarc.org/wp-content/uploads/2016/05/LNG-Markets-in-Transition_A-Corbeau-and-D-Ledesma.pdf*

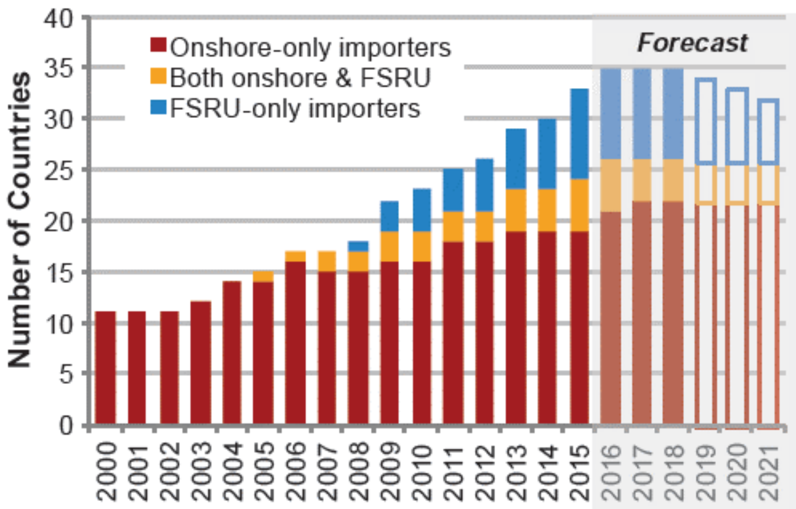
nine (or around 30% of the total) used only FSRUs and a further five use both onshore terminals and FSRUs. This compares with just one country ten years ago using FSRUs.

Figure 13 Start-ups of LNG receiving terminals, 1980-2021



Source: IGU (2016), *World Gas LNG Report*

Figure 14 Import markets by terminal type, 2000-21



Source: IGU (2016), *World Gas LNG Report*

2.4 Examples of new LNG importers

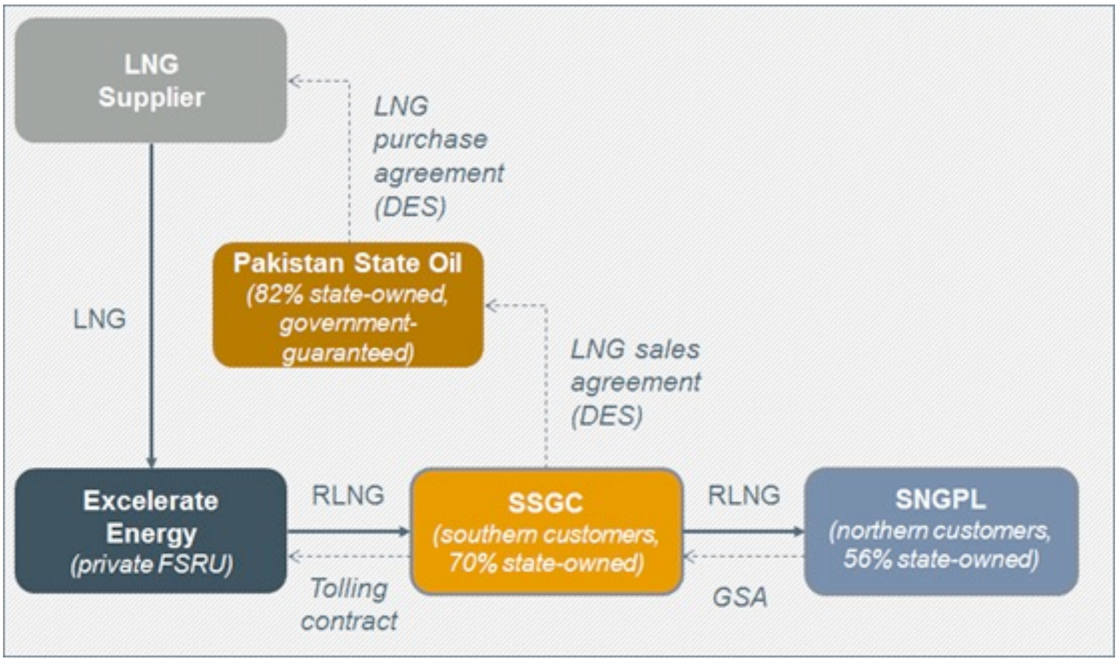
The increasingly flexible LNG market has opened up new routes for countries to begin LNG imports. Rather than the traditional model of a state monopoly signing long-term supply contracts, countries are now exploring options including multiple buyers using the same import infrastructure, short-term contracting and master framework contracts with varying volumes being procured competitively under these. In 2015, the new importing countries of Egypt, Pakistan and Jordan (for two-thirds of demand) all relied on short-term contacts

Pakistan provides a good example of how these new importers have structured their commercial arrangements. Originally, Pakistan's policy was that private firms would procure and import LNG and sell directly to customers using their rights of third party access (TPA) to the onshore pipeline networks. This failed as no private firms were able to take on the substantial credit risks and no suppliers were willing to sell LNG given the lack of creditworthy purchasers.

The model that has worked to begin LNG imports is illustrated in Figure 15, below. Its main features are:

- Procurement of LNG is separated from ownership of the import terminal.
- LNG procurement is by Pakistan State Oil Corporation (PSO). As well as having expertise in international procurement of petroleum products, PSO also holds a government guarantee enshrined in law.
- PSO purchases LNG through tenders. Each delivered cargo is immediately resold at the contract price plus a small margin to Sui Southern Gas Corporation (SSGC), the owner of the gas transmission and distribution network in southern Pakistan where the import terminal is located. While majority state-owned, SSGC has no formal government guarantee. Inserting PSO as an intermediary between LNG suppliers and SSGC allows its government guarantee to be used to provide confidence to suppliers that they will be paid in full.
- The import terminal is an FSRU leased from Excelerate Energy, a private firm. SSGC pays Excelerate a fixed fee to regasify and send-out LNG—a 'tolling' arrangement. A take-or-pay arrangement is in place so that Excelerate takes no volume risk—it is paid regardless of actual volumes regasified. By separating LNG procurement and terminal operation in this way, the risk to the operator is reduced increasing private sector interest.
- SSGC sells part of the regasified LNG to its own customers and part to Sui Northern Gas Pipelines Limited (SNGPL) which supplies the northern part of Pakistan.

Figure 15 LNG import arrangements in Pakistan



Source: Consultant research

We provide below a summary of the staged development of LNG imports into Pakistan under this model. This provides an example of how use of a terminal can gradually be expanded as demands become more certain.

Developing LNG imports – the example of Pakistan

The first six cargoes were procured on a spot basis from Qatar Gas (FOB[7] basis). This requirement was effectively imposed by access restrictions to the terminal due to failures to dredge channels which led to the FSRU itself being used to load and deliver the cargoes.

Following this, a series of short-term contracts were competitively tendered (DES basis[8]) These tenders were initially from one to six cargoes at a time and for up to two cargoes to be delivered per month. The first such tender was issued in early-May 2015 with a four-week period allowed for bids. The first cargo under the tender arrived in mid-July 2015. While Pakistan has tried to procure cargoes with as short a lead-time as one month, it is reported that these have generally attracted little interest due to limited available cargoes. Procurements two or more months ahead have seen significant interest from trading companies.

Pakistan has now managed to move to longer-term competitive procurements. In December 2015, Pakistan launched two tenders of 60 cargoes each to be delivered from January 2016 until December 2020. The winners were Shell and a Swiss-based trading company, which offered a price of 13.83% and 13.37% indexation to Brent oil prices, respectively[9] (~$6.5/mmbtu).

Government-to-Government negotiations with Qatar over long-term supply contract took 18 months to conclude with the Pakistan signatory being the state-owned and guaranteed Pakistan State Oil company. In February 2016, Pakistan State Oil signed a 15-year LNG supply contract with Qatar Gas.

Another example is offered by Jordan, which also started LNG imports in 2015. The main features of the Jordan procurement model are:

- A pool of potential suppliers is pre-qualified.
- All bidders sign a Master Sales and Purchase Agreement which sets out the standard terms and conditions for LNG purchases.
- The procuring agency, the National Electric Power Company of Jordan, issues notices for spot procurements as and when required. These specify the volumes and delivery window. All other conditions are already specified in the master agreement.
- Bidders submit price offers to supply the requested cargoes with the lowest-cost being accepted.

Excerpts from an example tender notice are shown below. The flexibility and speed of this arrangement is apparent. One week is allowed for receipt of bids and two days for evaluation. The first cargo is due for delivery within seven weeks of confirmation of the winning bidder.

[7] Free-On-Board, or price when loaded. It is the buyer's responsibility to arrange shipping from the port of loading to the port of delivery.

[8] Delivered-Ex-Ship or price when offloaded. It is the seller's responsibility to arrange shipping from the port of loading to the port of delivery.

[9] http://www.icis.com/resources/news/2015/12/16/9953654/pakistan-awards-mid-term-lng-tenders-to-two-winners-sources/. Indexation represents the linkage of the LNG price to the oil price so that an indexation of 13.37%, for example, would mean the LNG price (on a DES basis) is calculated as 0.1337 multiplied by the reference crude oil price (in $ per barrel).

Figure 16 Example spot tender documentation in Jordan

Contract Requirements	
Total Contract Volume	Two cargos of LNG
Delivery Timing	**Cargo #1 06 October 2015 through 07 October 2015.** **Cargo #2 12 October 2015 through 13 October 2015.**
Delivery Point	LNG is to be provided on a DES (Delivered Ex-Ship) basis to the Terminal
Contract Quantity	3.0 – 3.6 TBtu per cargo
Delivered LNG Volume	No greater than 155,500 m³ per cargo *(i.e. equivalent to 160.000m³ LNGC)*
Other Terms and Conditions	As detailed in the MSA executed between the Bidder and NEPCO

RfP release date	12 August2015
Deadline for NEPCO to receive MSA signed by Bidder	16 August 2015
Bid Submission Window	11:00 to 12:00 (Jordan time), 18 August 2015
Confirmation Notice executed by NEPCO	No later than 18:00 (Jordan time) on 20 August 2015

2.5 Conclusions

Procurement of LNG is becoming increasingly flexible with the advent of leased FSRUs and proliferation of spot and short-term contracts. This offers significant benefits to new importers who are unable or unwilling to commit to long-term take-or-pay obligations for large LNG volumes. Such is likely to be the case in Myanmar at the beginning of imports given the uncertainties surrounding the volumes required (see the following Section 3).

The examples of Pakistan and Jordan have been used to show how this flexibility can be used. In Pakistan, the procurement of the FSRU and of LNG have been separated to better manage the credit risks involved in the latter. The FSRU is remunerated under a tolling arrangement where the terminal owner is paid for regasification of delivered LNG on a take-or-pay basis, giving them protection against procurement risks that FSRU providers are not necessarily well-placed to manage. Imports started with spot cargoes and have now extended to a five-year contract with flexibility over timing of deliveries alongside a 15-year traditional contract arrangement. In Jordan, prospective LNG suppliers enter into a master sales agreement with the power company, which then conducts tenders for small numbers of cargoes on an as-required basis under the terms and conditions in this master agreement. This preserves flexibility as regards quantities to be procured while avoiding the time-consuming need to negotiate new contracts each time a procurement is made.

3 Myanmar's LNG import requirements

3.1 Introduction

In this section we provide estimates of the demand for LNG in Myanmar drawing on a number of recent studies. There is no requirement in the Terms of Reference for this assignment to develop our own forecasts of natural gas demand and supply in Myanmar and of the consequent needs for LNG imports.

The analysis highlights the uncertainties around both forecasts of domestic supplies of gas and, critically, the demand for gas in Myanmar. The impacts of these uncertainties on the potential range of required LNG imports is shown.

All forecasts for gas demand and supply in this section are presented in millions of standard cubic feet per day (mmscfd). Where individual studies present forecasts on cubic feet, these have been converted to standard cubic feet by adjusting for differences in heating values[10].

3.2 Studies reviewed

Four different studies, issued between 2014 and 2016, have been consulted. These are as follows:

- **JICA PMP 2014**. [JICA (December 2014), *Formulation of the National Electricity Master Plan*, Final Report: Summary]. This study was conducted for the then-Ministry of Electric Power during 2014 by a consultant team funded through the Japanese International Cooperation Agency (JICA). It represents the first power master plan (PMP) prepared for Myanmar. The PMP is not currently publicly-available and is undergoing revisions, again with JICA assistance, in the light of changes in policy following the formation of the new Government in early-2016. These changes include barring future coal-plant development and suspending expansion of large hydropower projects pending further assessment of their social and environmental impacts.

- **EMP 2015**. [IES and MMIC (December 2015), *Myanmar Energy Master Plan*]. The Energy Master Plan (EMP) was issued in its final form in December 2015. The EMP was developed during 2014-15 for the National Energy Management Committee by a consultant team under Asian Development Bank (ADB) funding and covers the oil, natural gas, coal and power sectors. A copy of the EMP is available at: http://www.burmalibrary.org/docs22/2015-12-Myanmar_Energy_Master_Plan.pdf

- **METI 2016**. [METI (February 2016), *Gas Value Chain*]. This study was prepared for the Ministry of Economy, Trade and Industry (METI) in Japan by a consortium of Nippon Koei, Mitsui & Co and Tokyo Gas. It provides a comprehensive overview of Myanmar's gas industry including historic and projected supply and demand. A copy of the full study report in Japanese is available at: http://www.meti.go.jp/meti_lib/report/2016fy/000957.pdf. An English-language summary is available at: http://www.meti.go.jp/meti_lib/report/2016fy/000958.pdf

[10] ***The calorific values used are: 1 scf = 1,027 Btu, 1 cf Yadana = 722.7 Btu, 1 cf Zawtika = 944.8 Btu, 1 cf Shwe = 987.8 Btu, 1 cf onshore = 1,014.1 Btu (volume-weighted average of Nyaung Dong and Apyauk fields). No adjustment is made for supply from new fields.***

- **e.Gen 2016**. [e.Gen (July 2016), *Study on Economic Costs of Natural Gas for Myanmar Domestic Market*, Draft Final Report]. This study was prepared by e.Gen Consultants for the World Bank. It calculates the economic or long-run average cost of gas supply in Myanmar. As part of this, the study provides projections of future gas supply and demand by location in Myanmar. The final study report has not yet been publicly issued but an overview of the study is published in the form of the Inception Report, available at: https://energypedia.info/wiki/File:Final_Inception_Report_Economic_Costs_of_Natural_Gas_for_Myanar_Domestic_Market.pdf

There are some interdependencies between the different studies. In particular, the METI 2016 study's projections of gas-fired capacity draw on the JICA 2014 power master plan. However, each study has ultimately developed its own forecasts of gas demand and supply while, in each case, relying heavily on data provided by MOEE.

3.3 Forecast demand

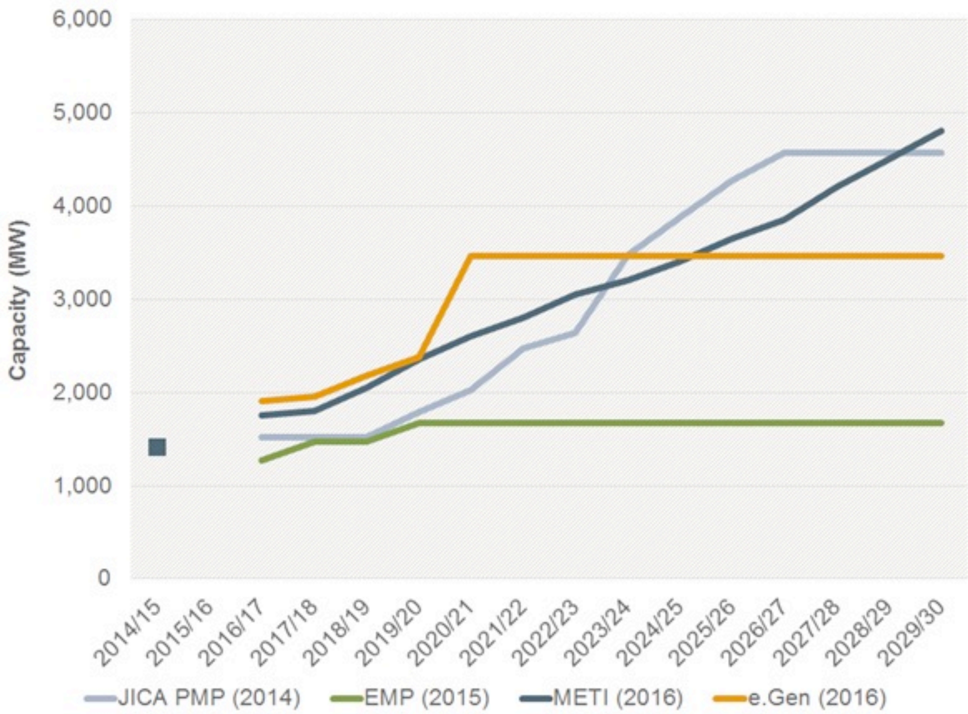
3.3.1 Power sector demand

The projected gas-fired power generating capacity under each study is shown below. As can be seen, these vary widely. Installed gas-fired capacity in 2014/15 is reported at 1,411 MW[11]. Projected capacity in 2016/17 ranges from a low of 1,270 MW in the EMP 2015 to a high of 1,905 MW in the e.Gen 2016 study.

Expansion paths thereafter also diverge widely. The EMP 2015 expects only very limited additions to gas-fired capacity. Instead, power sector demand is met from expanded hydropower and coal-fired capacity (it should be noted that the EMP was completed prior to the recent changes in Government policies on power sector expansion). The e.Gen 2016 study, based on the most recent data on planned projects provided by MOEE, projects the addition of 1,500 MW of gas-fired capacity to 2020/21 but, after that, expansion of generating capacity becomes driven by other fuels. By contrast, both JICA PMP 2014 and METI 2016 project a more gradual but larger expansion of gas-fired capacity over the next 10 years. By 2030, gas-fired capacity reaches 4.6 GW under JICA PMP 2014, 1.7 GW under EMP 2015, 4.8 GW under METI 2016 and 3.5 MW under e.Gen 2016.

[11] *Deloitte (August 2015), Myanmar Power Sector Financial Analysis and Viability Action Plan, Inception Report. Available at: https://energypedia.info/wiki/File:TA-financial-action-plan_Final_Inception_Report_-_16_Sep_2015_vF.pdf*

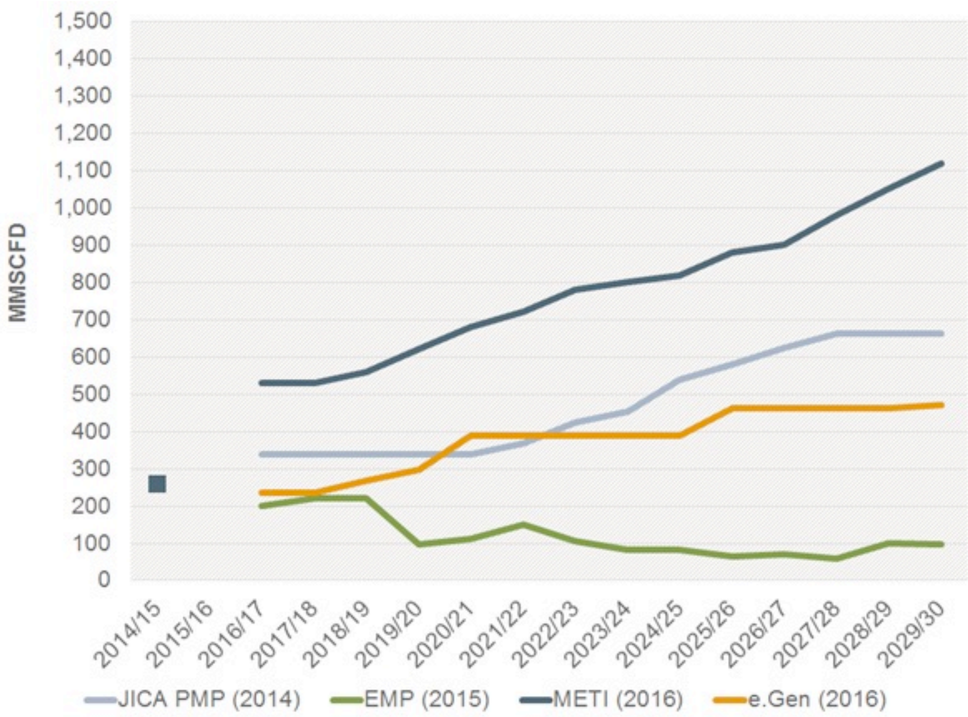
Figure 17 Gas-fired power generating capacity, 2015-30



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016

These very different forecasts for gas-fired generating capacity are reflected in the various studies' forecasts for gas demand from the power sector. These are shown below. Demand in 2014/15 was equivalent to 257 mmscfd. Under EMP 2015 this is projected to decline as lower-cost hydropower and coal-fired generation comes to dominate. Under e.Gen 2016, gas demand approximately doubles by 2025 and, thereafter, remains constant. The JICA PMP 2014 sees demand at around 350 mmscfd to 2020 and almost doubling from this by 2030 as gas-fired capacity expands. The METI 2016 study projects continuing large increases in gas demand, reflecting its assumptions that coal-fired capacity expansion is delayed while electricity demand grows rapidly, reaching over 1,100 mmscfd by 2030.

Figure 18 Power sector demand for gas, 2015-30



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016

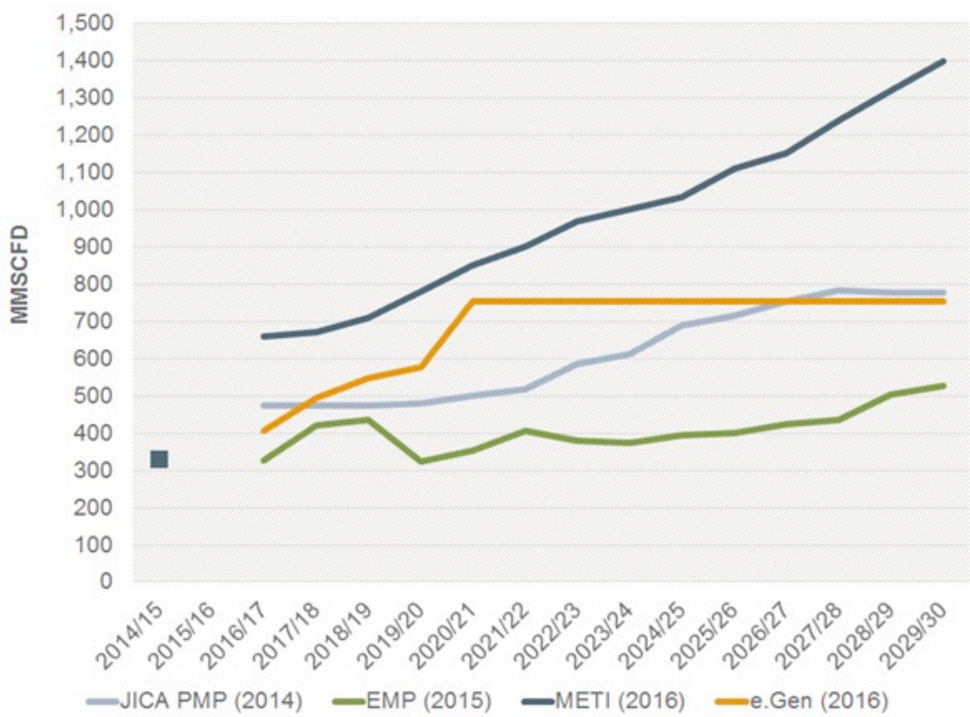
3.3.2 Total demand

The JICA PMP 2014 and METI 2016 study both forecast that demand from natural gas from users other than the power sector will be a relatively small part of total demand, at 140 to 160 mmscfd in 2020 (20% to 30% of total demand) and reaching 115 to 280 mmscfd in 2030 (15% to 20% of total demand). The apparent fall in non-power sector demand for gas in JICA PMP 2014 is not explained. The e.Gen 2016 study, based on bottom-up assessments developed with MOEE inputs, forecasts higher demand from the non-power sector which reach 280 mmscfd in 2020 or half of total demand.

The outlier is EMP 2015 which both forecasts higher non-power sector demand and, because of its much lower expectations for demand for gas from the power sector, a much larger share for non-power sector demand in total demand for gas. By 2020, EMP 2015 forecasts non-power sector demand of 230 mmscfd (70% of the total) rising to 430 mmscfd by 2030 (80% of the total). This demand growth is largely driven by consumption of gas in industry. Other contributing factors are the assumed development of a 50,000 barrel per day (BPD) hydro-cracking refinery and the construction of two new fertiliser plants to enable Myanmar to meet most of its requirements domestically. Each of these consumes approximately 30 mmscfd meaning a total additional demand nearing 100 mmscfd relative to other forecasts that assume no such developments.

Forecast total gas demand including both power sector and non-power sector uses under the different studies is shown below. Due to its much lower forecast power sector demand, total demand under EMP 2015 is forecast at around 500 mmscfd by 2030, despite the much larger non-power sector demand forecast. The JICA PMP 2014 and e.Gen 2016 studies both forecast total demand in 2030 of around 800 mmscfd, although non-power sector demand forms a much larger part of total forecast demand in the latter. The METI 2016 study forecasts a much higher total demand of 1,400 mmscfd by 2030 reflecting the scale of forecast demand from the power sector.

Figure 19 Total demand for gas, 2015-30



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016

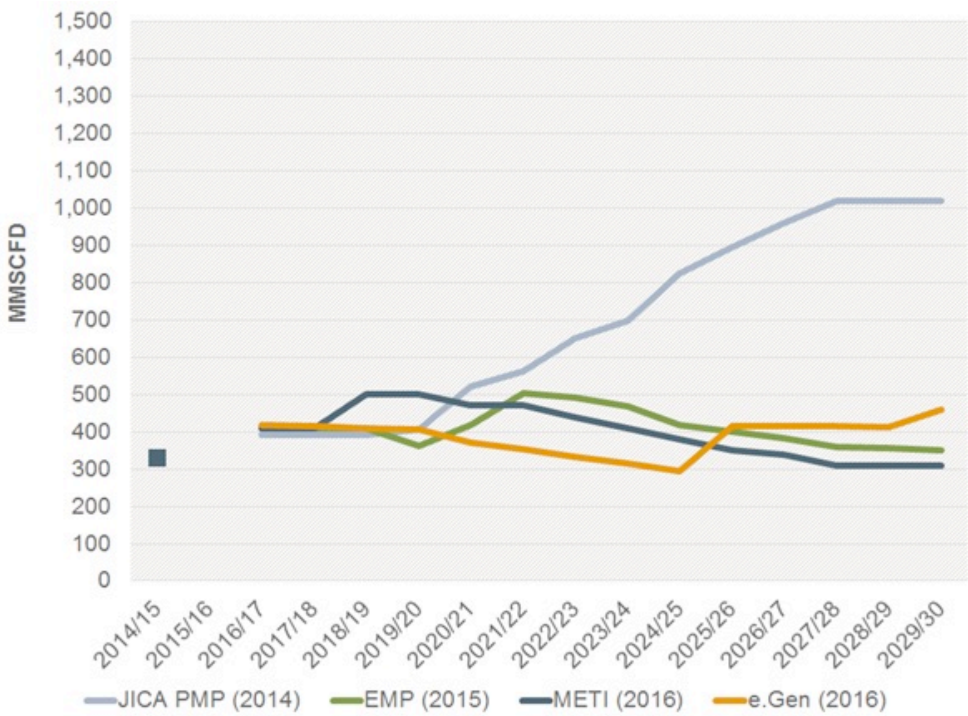
3.4 Forecast supply

Of the four studies, three (EMP 2015, METI 2016 and e.Gen 2016) concur that there will be a slow downward trend in domestic gas supply to 2030. The coming on-stream of the Zawtika and Shwe fields initially raises supplies from their 2014/15 level of 330 mmscfd (when these fields were only partially operational). However, subsequent declines in production from the Yadana and Zawtika fields lead to a decline from 2020 onwards which is only partially offset by new supplies from Block M-3 starting from 2022 (under EMP 2015) or 2025 (e.Gen 2016). The e.Gen 2016 study also includes production from the Badamyar block from 2030. None of these three studies assume supply from either the A-6 or AD-7 blocks commencing within the period of the forecasts, unsurprisingly given that Woodside only announced its gas discoveries in these blocks in the 2016Q1.

The JICA PMP 2014 also forecasts declining supply from the Yadana field commencing from 2020 and from the Zawtika field from 2025 with this being partially offset by the commencement of production from Block M-3 from 2020. However, it includes assumed large supplies from unnamed new fields which more than offset these production declines and are sufficient to meet Myanmar's total demand for gas.

The supply forecasts in the various studies are shown below. These are for available supplies to the domestic market in Myanmar only, not for total production including exports to Thailand and China. In theory, there is potential to increase supply by redirecting some of these exports to the domestic market—a possibility discussed in the following Section 4.

Figure 20 Domestic supply of gas, 2015-30



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016

In Table 1, we summarise the breakdown of the supply forecasts under the different studies for selected years (the METI 2016 study is excluded, as this does not provide forecasts for domestic supply on a field-by-field basis). This provides an indication of where the differences arise between the studies. The forecasts are presented in mmscfd and, therefore, may differ from the values frequently quoted which are for supplies in mmcfd without normalising these to a standard heating value.

In addition to the points noted above, it is noticeable that the more recent e.Gen 2016 forecasts are significantly more pessimistic than those in both JICA PMP 2014 and EMP 2015 as regards the potential to increase onshore production but are more optimistic as regards continued, although diminished, supplies from the Yadana and Zawtika fields.

Table 1 Supply of gas by source, 2015-30

All mmscfd	Onshore	Yadana	Zawtika	Shwe	M-3	Other new (a)	Total
2014/15							
Actual	60	187	57	25	0	0	**329**
2019/20							
JICA PMP 2014	61	105	88	92	61	0	**407**
EMP 2015	64	110	92	96	0	0	**363**
e.Gen 2016	42	176	92	96	0	0	**406**
2024/25							
JICA PMP 2014	90	47	76	92	131	390	**826**
EMP 2015	96	38	39	96	150	0	**419**
e.Gen 2016	32	74	92	96	0	0	**294**
2029/30							

All mmscfd	Onshore	Yadana	Zawtika	Shwe	M-3	Other new (a)	Total
JICA PMP 2014	97	0	8	92	131	689	**1,018**
EMP 2015	104	0	0	96	150	0	**350**
e.Gen 2016	25	56	92	96	142	47	**458**

Source: JICA PMP 2014, EMP 2015, e.Gen 2016

(a) Badamyar field for e.Gen 2016 forecasts. Unidentified for JICA PMP 2014 forecasts.

3.5 Forecast LNG import requirements

Figure 21, below, brings together the demand and supply forecasts above to show the resulting forecast deficits in domestic supply relative to domestic demand under each study. As can be seen, these vary widely:

- **JICA PMP 2014** forecasts a small deficit up to 2020 but, after this, increased supply from new domestic fields means demand-supply balance is restored.

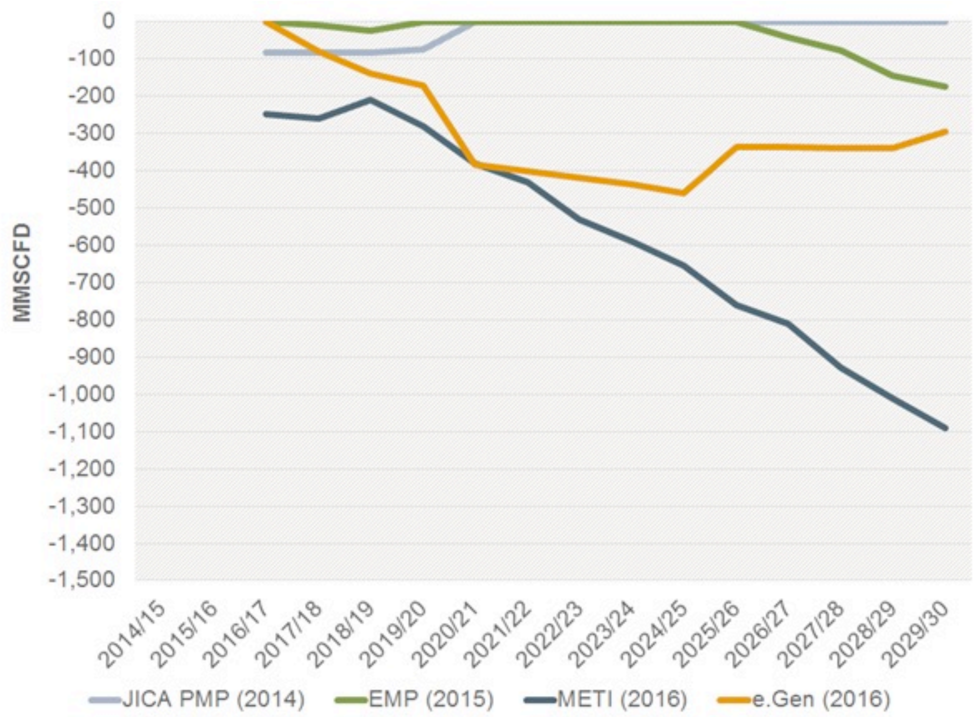
- **EMP 2015** forecasts a very small deficit up to 2020 and then the restoration of balance until around 2025, after which the deficit starts to grow, reaching 200 mmscfd by 2030.

- **METI 2016** forecasts deficits throughout the period, starting at around 300 mmscfd in 2017 and rapidly growing from 2020 onwards to reach 1,100 mmscfd by 2030. This reflects the large projected demand for gas from the power sector alongside the assumption that no new large domestic fields will start production over this period.

- **e.Gen 2016** also forecasts deficits throughout the period. While reaching 400 mmscfd by 2020, as under the METI 2016 forecast, they are flat thereafter due to the expected lack of growth in power sector demand for gas. By 2030, with the start of M-3 and Badamyar production, the deficit is forecast to decline slightly to around 300 mmscfd.

Comparisons of demand and supply forecasts for the individual studies are presented in Section A.

Figure 21 Gas supply deficit, 2015-30



Source: JICA PMP 2014, EMP 2015, METI 2016, e.Gen 2016

The resulting requirements for LNG imports to close these forecast deficits, assuming these imports can start from 2020, are shown below. These are presented in million tonnes of LNG received per annum (MTpa).

The impacts of the uncertainty around future gas demand and domestic supply in Myanmar on estimated LNG import requirements are immediately apparent:

- At one extreme, using the forecasts in JICA PMP 2014, there is no requirement for imports at all over the period to 2030.

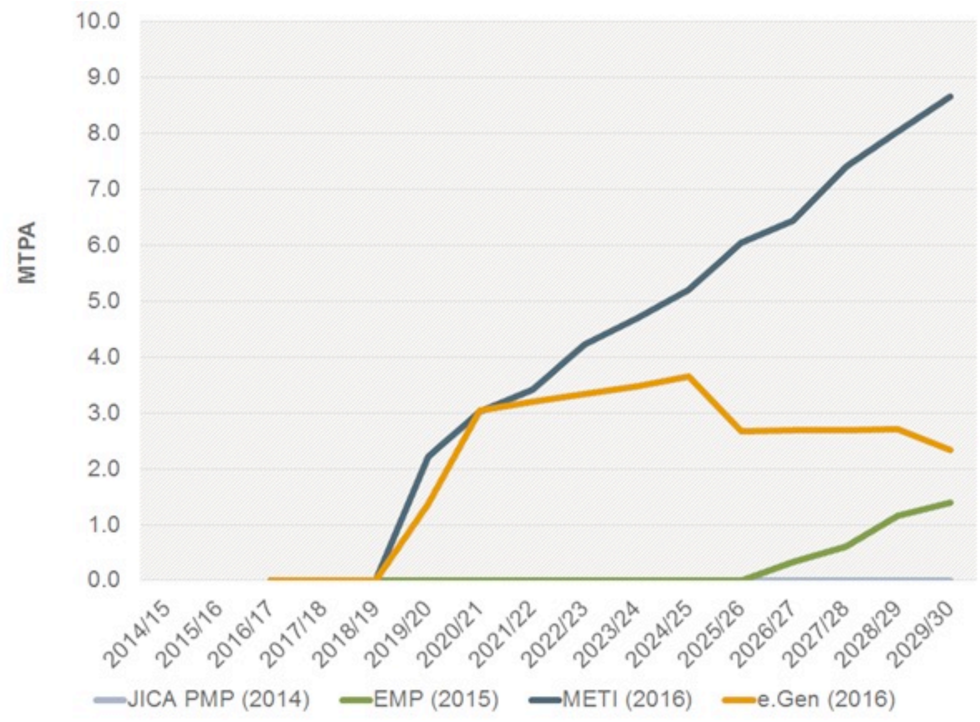
- At the other extreme, using the METI 2016 forecasts, requirements for LNG imports start at 2.2 MTpa in 2020 and rise continually to reach 8.7 MTpa by 2030. This is equivalent to around 55 cargoes[12] annually by 2030 and roughly equivalent to Spain's current annual import volumes (the seventh-largest importer in the world at present).

- The EMP 2015 forecasts imply a requirement for LNG imports starting at very low volumes in 2027 and reaching only 1.4 MTpa (equivalent to nine cargoes per year) in 2030.

- Lastly, the most recent forecasts in e.Gen 2016 would imply LNG imports starting in 2020 at 1.4 MTpa, peaking in 2025 at 3.7 MTpa (equivalent to 23 cargoes per year) and then declining again to 2.3 MTpa (equivalent to 15 cargoes) in 2030.

[12] *Assumes a cargo size of 160,000 m^3.*

Figure 22 LNG import requirements, 2015-30



Source: Consultant calculations

Estimated LNG import requirements, based on these four recent studies, would, therefore, mean anything from the need to develop a large-scale import facility immediately (under the METI 2016 forecasts) to being able to defer the need for imports to sometime after 2025 and then only requiring these on a small scale (under the JICA PMP 2014 and EMP 2015 forecasts).

3.6 Conclusions

The uncertainty over natural gas demand and domestic supply in Myanmar is readily apparent from the comparison of forecasts in this section. In turn, this means that the need for LNG imports and the timing of these imports is extremely uncertain.

Overall, the conclusion reached is that the level of uncertainty is such that preserving flexibility is paramount in decisions on the sizing, location and commercial arrangements for LNG imports. This implies that the emphasis in developing procurement strategies should be to preserve flexibility. Rather than entering into long-term supply contracts, Myanmar should be looking to initially rely on short-term and flexible arrangements in order to be able to adapt import volumes to needs. This is also consistent with the use of an FSRU under a lease arrangement which allows for replacement or removal of the terminal if import requirements prove to be higher or lower than initially expected.

4 Review of potential gas swaps

4.1 Introduction

All four forecasts reviewed in the preceding section expect to see a small supply deficit during the period to 2020 when a new LNG import terminal might commission. Among the proposals for addressing this has been that of gas swaps under which Myanmar would substitute LNG imports into Thailand for pipeline gas exports, thus freeing up gas previously allocated to export to supply the domestic market. Other options include buyback of some gas committed to export and the use of fuel oil as a substitute for gas in power generation.

We consider the potential for short-term swaps to be limited to Thailand. As discussed in our separate report on siting options for the proposed LNG import terminal, additional gas will initially need to be supplied to the Yangon area. In the short-term, this is only physically possible by diverting exports to Thailand given the lack of any available pipeline capacity linking the Shwe export pipeline to Yangon.

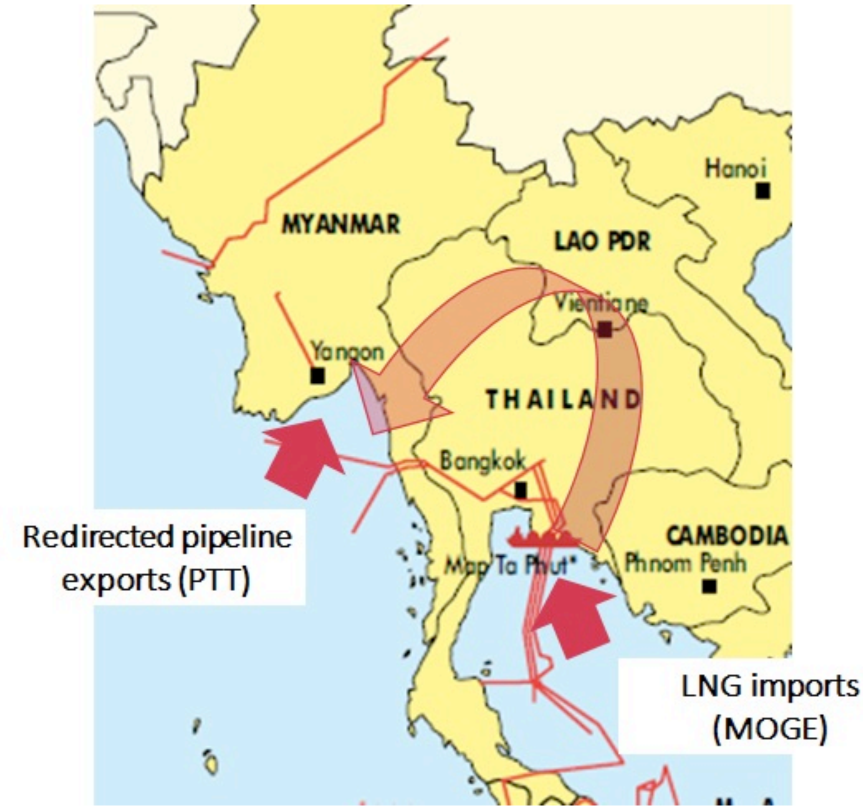
Separately, proposals have also been made for Myanmar to procure additional LNG cargoes to be delivered to the LNG import terminal being proposed by PTT for future supply to Thailand as output from Yadana and Zawtika declines. These cargoes would be used to substitute for gas that would otherwise have been exported from Yadana, allowing part of this to be redirected to domestic supply. As this medium-term swap arrangements introduces different considerations from short-term swaps, we discuss it separately below.

4.2 Short-term swaps

4.2.1 Outline arrangement

A short-term swap arrangement would be a temporary expedient used to increase gas supplied to the Myanmar market prior to the commissioning of the new LNG terminal. At a conceptual level, Myanmar Oil and Gas Enterprise (MOGE) would import LNG cargoes into the existing Map Tha Phut LNG terminal located in Thailand for PTT's use and, in return, would receive an increased allocation of gas production from the Yadana and/or Zawtika fields for domestic consumption in Myanmar. The arrangement is illustrated below.

Figure 23 Illustrative short-term gas swaps arrangement



There is little experience of similar cross-border swaps of LNG for pipeline gas. Those we have identified are:

- A pipeline gas for LNG swap in 2005, when Gazprom swapped an increase in pipeline gas supplied to Gaz de France in return for a single LNG export cargo originated by Gaz de France.
- The swapping, in 2013, of six LNG cargoes from the Tangguh gas facility in Indonesia for contracted exports to South Korea from the Arun LNG facility, also in Indonesia. These cargoes were swapped for pipeline gas deliveries from the Arun facility to a local fertiliser company which did not have its own LNG import facilities.
- More recently, Gazprom in 2015 proposed swapping pipeline exports to Iran's north for LNG cargoes exported from its south (through a Gazprom-owned terminal, to be constructed) but no progress appears to have been made.

Given this lack of precedents, we have made our own assumptions on how a short-term swaps model might operate. We assume that MOGE would procure cargoes for delivery into Thailand's Map Tha Phut LNG receiving terminal on a DES basis. MOGE would also be responsible for paying all charges associated with unloading, storing, regasifying and sending-out regasified LNG (RLNG). Transfer of title to the RLNG and responsibility for delivery to customers would transfer to PTT at the entry to PTT's transmission pipeline system. In return for the delivered LNG, PTT would release corresponding amounts of gas for use in Myanmar to be delivered through MOGE's transmission pipeline system.

Below, we review the key issues related to such an arrangement which are the commercial and legal requirements, the physical requirements which derive from the physical capacity of PTT's and MOGE's gas transmission systems to handle such an arrangement and the costs and benefits of such an arrangement for Myanmar.

4.2.2 Commercial and legal requirements

We understand that, as the existing gas supply agreements between Myanmar and Thailand were signed on a Government-to-Government basis, significant amendments will require approval by Thailand's Office of the Attorney-General and by the National Energy Policy Council (equivalent to a Cabinet committee and chaired by the Prime Minister). Such approvals will only be granted if it can be shown that any changes, such as a swaps arrangement, do not increase costs or risks of supply interruptions to Thailand.

At this time, it would be very hard to provide the necessary assurances. MOGE has no experience in LNG procurement and, therefore, is in no position to initiate LNG purchases in the immediate future. Even if this barrier can be overcome, MOGE will still be faced with the need to provide adequate guarantees of its capability to pay for LNG cargoes given its lack of a track record and the poor financial condition of its main customer—the power sector. These may be very substantial. A single LNG cargo of 140,000 cubic metres would cost around US$ 16.5 million[13], even at current historically low prices. This effectively limits MOGE to only purchasing individual or small numbers of LNG cargoes at a time which, in turn, means it cannot guarantee supply to PTT.

4.2.3 Physical requirements

PTT's onshore gas transmission system

The following constraints have been identified in discussions with PTT:

- **LNG terminal capacity**. Until commissioning of Phase 2 of the Map Tha Phut LNG terminal, expected in 2017, PTT is concerned that the existing terminal has insufficient storage and send-out capacity to both ensure security of gas supply to PTT's customers in peak periods and to accommodate additional volumes substituting for Myanmar pipeline imports.

- **Onshore transmission**. After Phase 2 of the terminal is commissioned, there will still be constraints on PTT's transmission pipeline system which would mean incremental volumes cannot be flowed from the Map Tha Phut terminal to the Ratchaburi power plant complex, which is currently supplied by imports from Myanmar. These constraints will be partially relaxed with the commissioning of a new compressor station in 2019 and fully once the Fifth Onshore Transmission Pipeline is commissioned, which is expected in 2021.

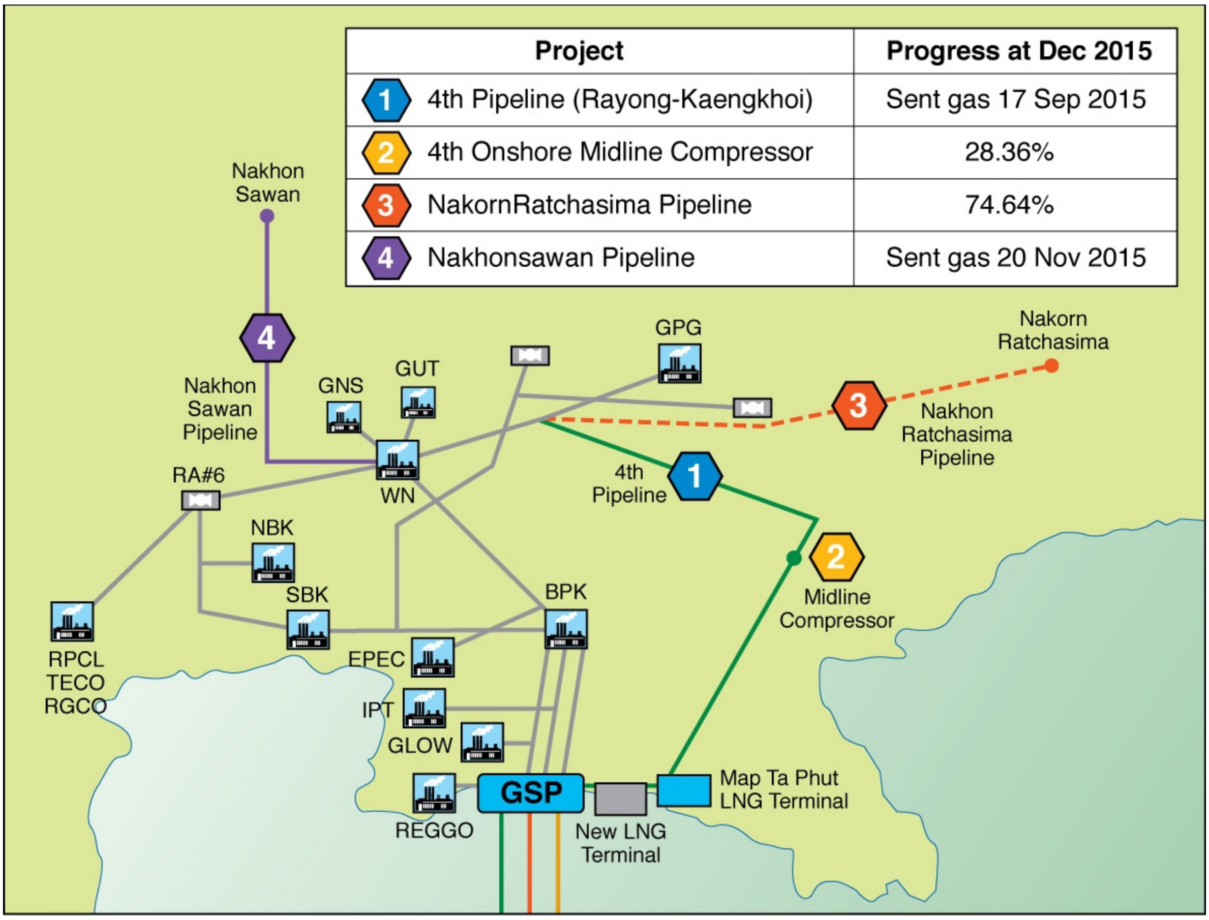
- **Gas specifications**. There may also be issues related to changing gas specifications. At present, the Ratchaburi power plants are configured to burn a mix of low-calorific value Yadana gas and higher-calorific value Yetagun and Zawtika gas. Reducing imports of Yadana gas and replacing them with RLNG would change the gas mix and, therefore, its specifications. This

[13] Assumes a 140,000 cm cargo, a conversion rate of 21.04 mmbtu to 1 cm of LNG and a DES price of $5.6/mmbtu (FERC's estimate of landed prices into India as of October 2016 is $5.57/mmbtu - https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf)

will reduce the combustion efficiency of the plants' burners and increase fuel consumption and costs.

The compressor station concerned is understood to be the 4th Onshore Midline Compressor, as illustrated on the stylised map of PTT's onshore transmission pipeline network shown below.

Figure 24 PTT's onshore transmission network



Source: PTT (http://ptt.listedcompany.com/misc/presentations/20160301-ptt-investor-update-201603-05.pdf)

Overall, it appears that any increase in LNG supplies delivered into Map Tha Phut under a swaps arrangement could not readily be transported to Ratchaburi to substitute for imports from Myanmar.

MOGE's gas transmission system

Any incremental gas made available to the domestic market on a short-term basis would need to flow from either the Yadana field to Yangon via the existing pipeline (24" capacity) or from the Kanbauk landing point for the various offshore pipelines to Yangon via Mawlamyine (24" and 20" capacity). However, neither pipeline could readily accommodate an increase in gas flows:

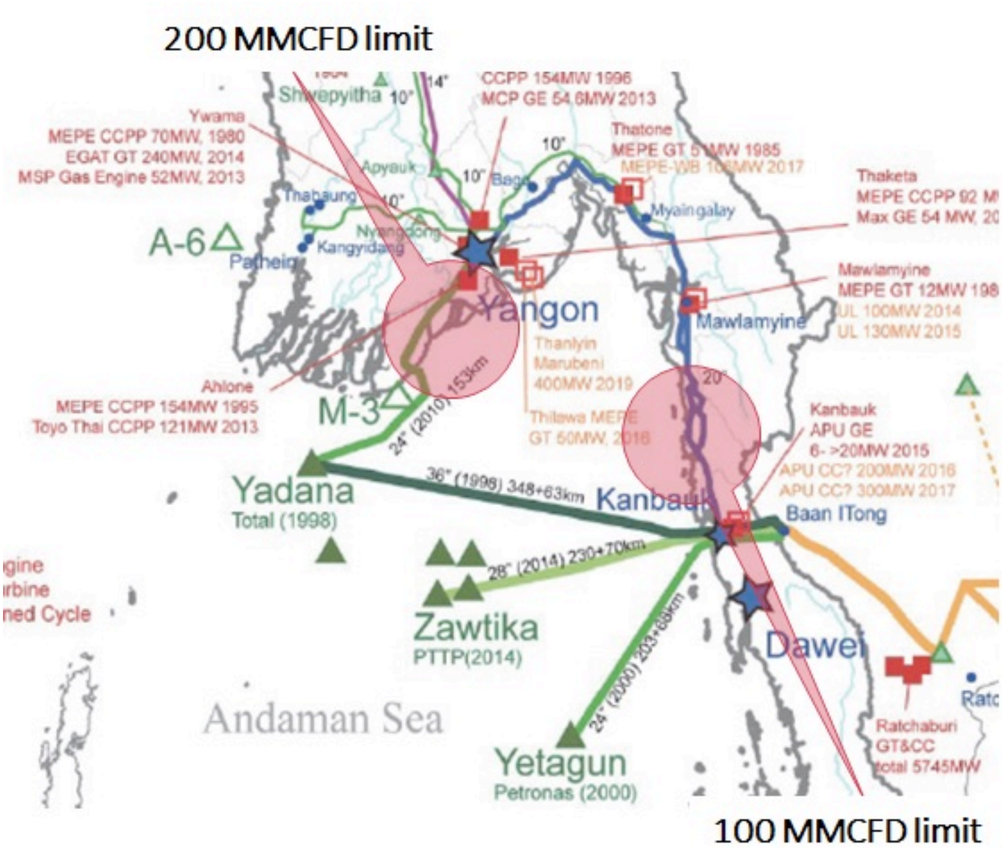
- **Yedana – Yangon pipeline**. The existing onshore section of the pipeline has a capacity of 200 mmcfd, although this is to be increased to 250 mmcfd. Utilisation as of October 2016 is 177 mmcfd but this rises to 200-210 mmcfd in the hot season when electricity demand peaks and hydropower generation is at its lowest. Therefore, additional supplies through this pipeline during the hot season, when they are most needed, would be limited to 40-50 mmcfd (equivalent to 35 mmscfd after adjusting for heating content). This compares to a potential deficit of up to 200 mmscfd depending on the forecasts used (see Section 3.5).

- **Kanbauk – Yangon pipeline**. The pipeline has a maximum capacity of 100 mmcfd to Mawlamyine. Utilisation as of October 2016 was 56 mmcfd and this rises to 100 mmcfd in the hot season, implying no additional gas supplies released as part of an LNG swap could be transported. Capacity is limited by the low pressures at which the pipeline operates which, in turn, are constrained by the poor condition of the pipeline. MOGE is replacing the pipeline to Mawlamyine but faces budget constraints. As of end-2015, 35 miles had been replaced but only 5-10 miles of replacement is budgeted in 2016. At this rate, full replacement of the 180 mile pipeline will require from five years upwards.

Physical constraints, therefore, suggest that the maximum supply that could be reallocated on a firm basis to domestic consumption under a short-term swaps arrangement would be 50 mmcfd or so from the Yadana field.

The pipeline constraints are illustrated below.

Figure 25 Major pipeline constraints in Myanmar



Source: Consultants and METI 2016

4.2.4 Cost-benefit analysis

In principle, the benefits of such a short-term swap arrangement appear high. They would enable Myanmar to meet demand for electricity using natural gas rather than oil fuels, reducing costs significantly. However, in practice, the physical constraints identified above mean that these potential benefits cannot be realised without significant investment to relieve these constraints. As well as the direct costs of the required investments these will probably delay the realisation of the potential benefits for at least two to three years, by which time the original motivation for the swaps (to close the supply and demand gap while a dedicated LNG terminal is being developed) is no longer applicable.

4.2.5 Conclusions on short-term swaps

The lack of precedents suggests that any such transaction would face significant obstacles to its development and implementation. Our own analysis has identified a number of major constraints:

- It is unlikely that MOGE can guarantee reliable supplies of LNG, leaving PTT at risk of interruptions.

- Physical constraints on PTT's gas transmission system mean that LNG delivered into Map Tha Phut cannot readily be transported to the Ratchaburi power complex which currently receives pipeline gas from Myanmar.

- Physical constraints on MOGE's gas transmission system means that the maximum increase in firm gas supplies that could be released by a swaps arrangement would be around 50 mmcfd (equivalent to 35 mmscfd).

Overall, we conclude that short-term swaps are infeasible. They are unlikely to be accepted by PTT and, even if implemented, would be unlikely to release significant additional quantities of natural gas to the Myanmar market. However, even if the constraints on the Thai side were lifted, Myanmar would still need to overcome infrastructure and capacity issues.

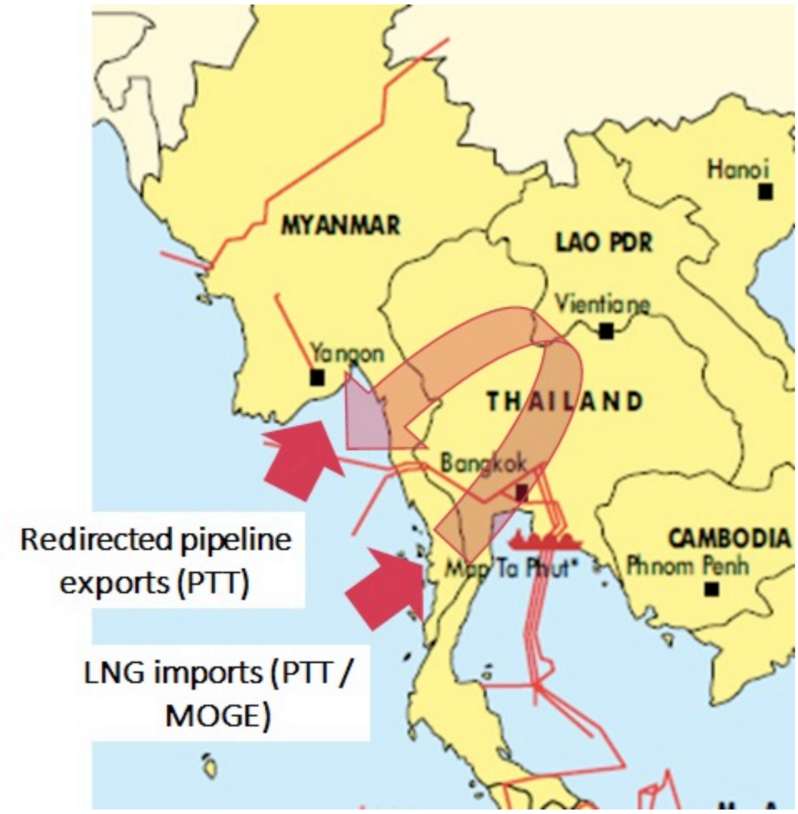
4.3 Medium-term swaps

4.3.1 Outline arrangement

PTT is currently investigating the potential to develop an LNG import terminal (in the form of an FSRU) at Kanbauk from 2020-21. This would be used for LNG imports to supply the Ratchaburi power plant complex using the existing export pipelines from Myanmar and would substitute for declining production from the Yadana and Yetagun fields.

This creates the possibility for swapping additional LNG imports through the new PTT-owned terminal for offshore gas production previously allocated for export. This would allow existing levels of supply from these fields to the domestic market to be maintained even as total production falls. Such a swaps arrangement would allow a reduction in the need for new LNG imports for Myanmar's own consumption to make up for declines in domestic supply from existing export-oriented fields. The arrangement is shown below.

Figure 26 Illustrative medium-term gas swaps arrangement



4.3.2 Commercial and legal requirements

The commercial constraints on such an arrangement would be less than under a short-term swaps arrangement as discussed above. We assume that PTT would be responsible for LNG imports, relieving MOGE of this responsibility. MOGE would need to compensate PTT for any difference between the cost of imports and the price paid for redirected gas that would otherwise have been exported.

While there would still be a need for higher-level approvals, we expect that these would be easier to obtain and there is also a longer lead-time to do so.

4.3.3 Physical requirements

Imported LNG would be transmitted to Thailand using the spare capacity on existing export pipelines released by diverting exports to domestic supply. As domestic supply from the Yadana and Zawtika fields would be maintained at current levels under these arrangements, MOGE's existing onshore transmission capacity should be adequate.

4.3.4 Cost-benefit analysis

Whether such a swap arrangement is advantageous to Myanmar depends on whether there will be continued physical constraints on delivery of natural gas to the Yangon area following the expected commissioning of a dedicated LNG import terminal. If constraints do exist then it is sensible to make maximum use of existing pipeline capacity which would imply replacing declining domestic supply from the Yadana and Zawtika fields, given that these have pipeline connections to Yangon. In this case, the benefits would be the reduced need for new pipeline investment to transport natural gas to Yangon. At this stage, we are not able to quantify the magnitude of these potential savings in the absence of decisions on the size and location of a new dedicated LNG terminal and on future pipeline investment plans.

In the absence of such pipeline constraints, Myanmar can meet its demand for gas from LNG imports through its own dedicated terminal/s. In such a case, the proposed swap would effectively mean PTT importing part of Myanmar's requirements indirectly rather than this being done directly through a dedicated terminal. This is unlikely to be more cost-efficient.

4.3.5 Conclusions on medium-term swaps

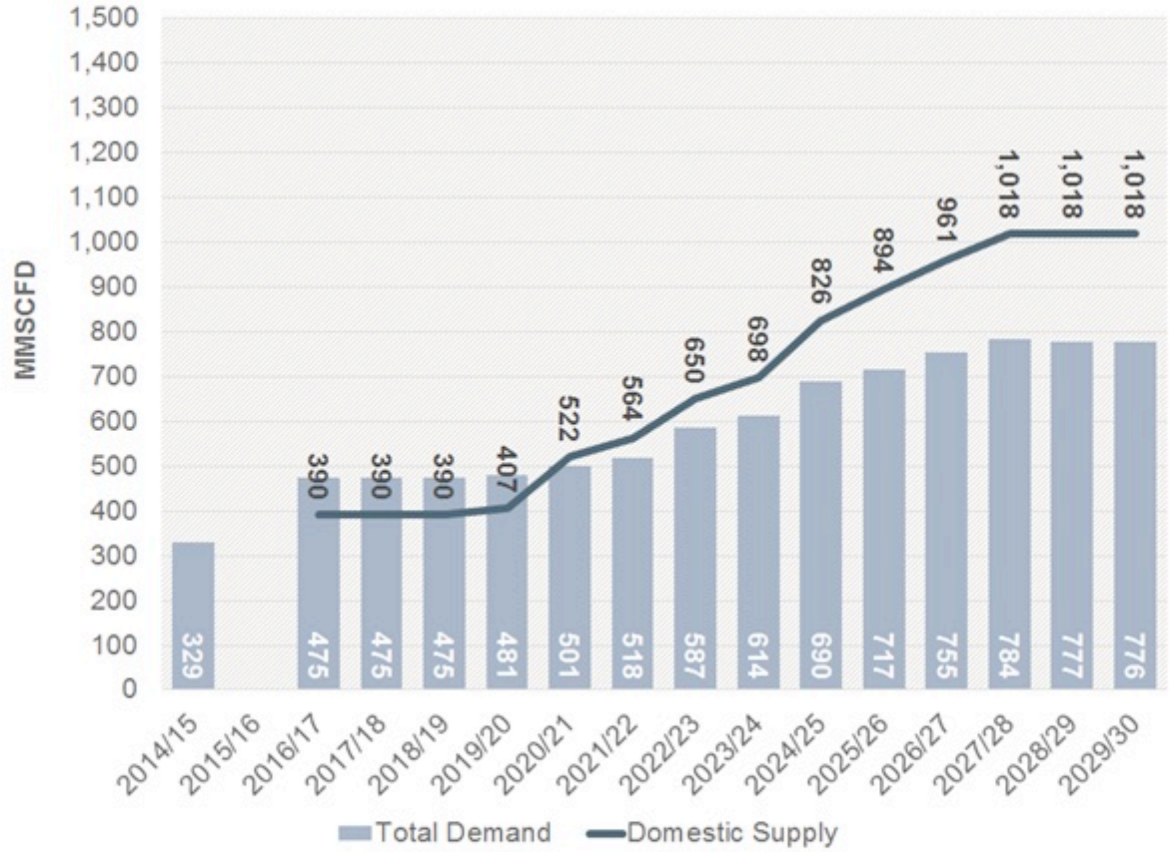
Medium-term swaps using a PTT-developed LNG import terminal located in Myanmar would have much reduced commercial and legal difficulties relative to short-term swaps and would not face the same physical constraints. If there continue to be constraints on supplying natural gas into the Yangon area following the commissioning of a new dedicated LNG import terminal then the net benefits to Myanmar of such swaps would be likely to be positive. If investments associated with the new LNG terminal relieves these constraints then the net benefits to Myanmar of swaps would appear to be zero to slightly negative.

ANNEXES

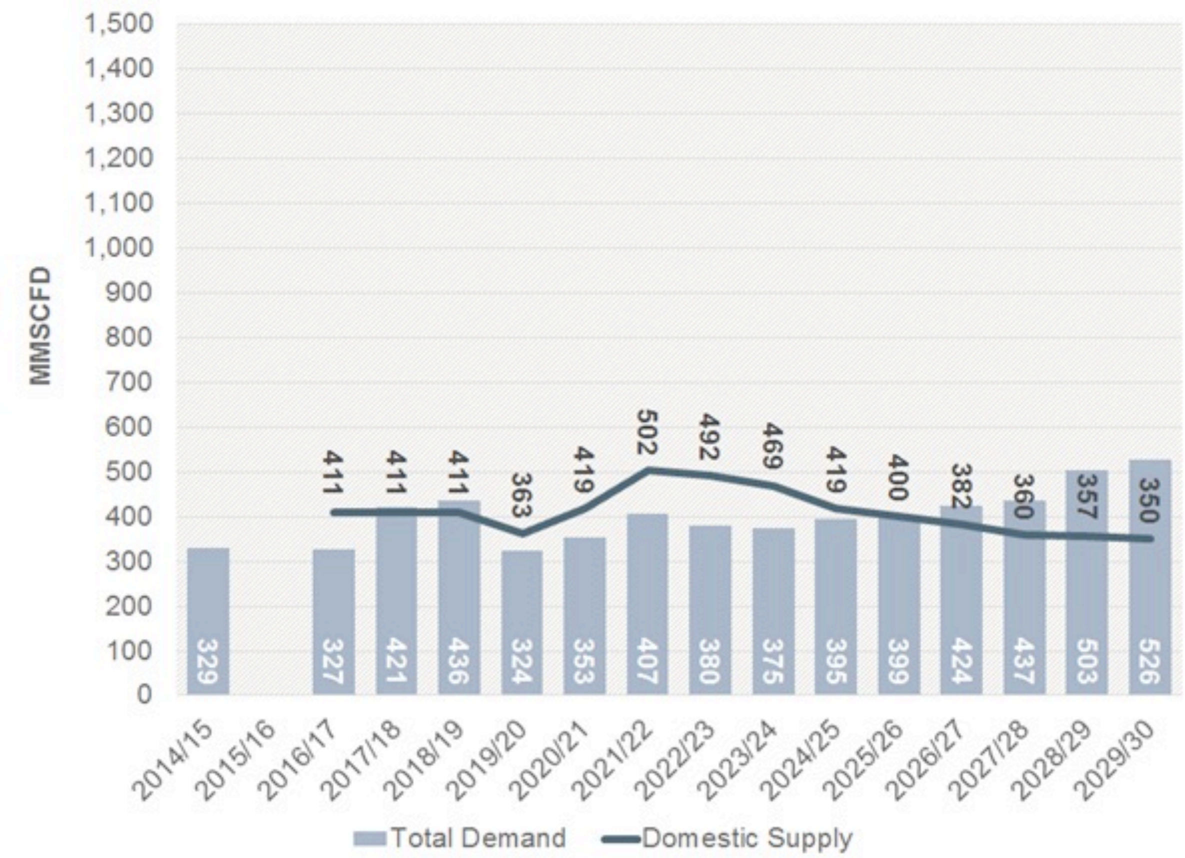
Section A Demand-Supply Forecasts by Study

The figures below show the individual demand and domestic supply forecasts for each of the four studies referenced in Section 2. In each case, these are presented in mmscfd.

A.1 JICA PMP 2014



A.2 EMP 2015


MMSCFD
1,500
1,400
1,300
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1,100
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500
400
300
200
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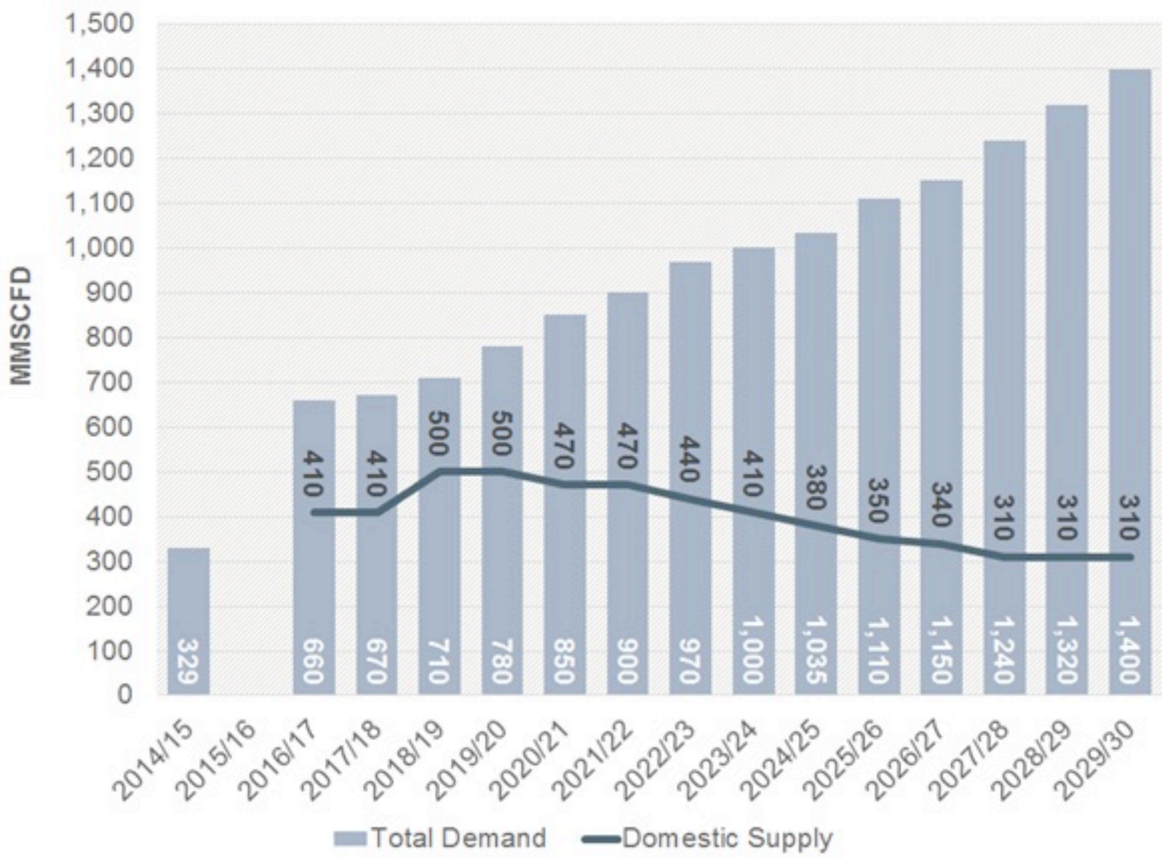
327
421
436
324
353
407
380
375
395
399
424
437
503
526
411
411
411
363
419
502
492
469
419
400
382
360
357
350
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
Total Demand
Domestic Supply

A.3 METI 2016


MMSCFD
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710
780
850
900
970
1,000
1,035
1,110
1,150
1,240
1,320
1,400
410
410
500
500
470
470
440
410
380
350
340
310
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2014/15
2015/16
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2019/20
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2022/23
2023/24
2024/25
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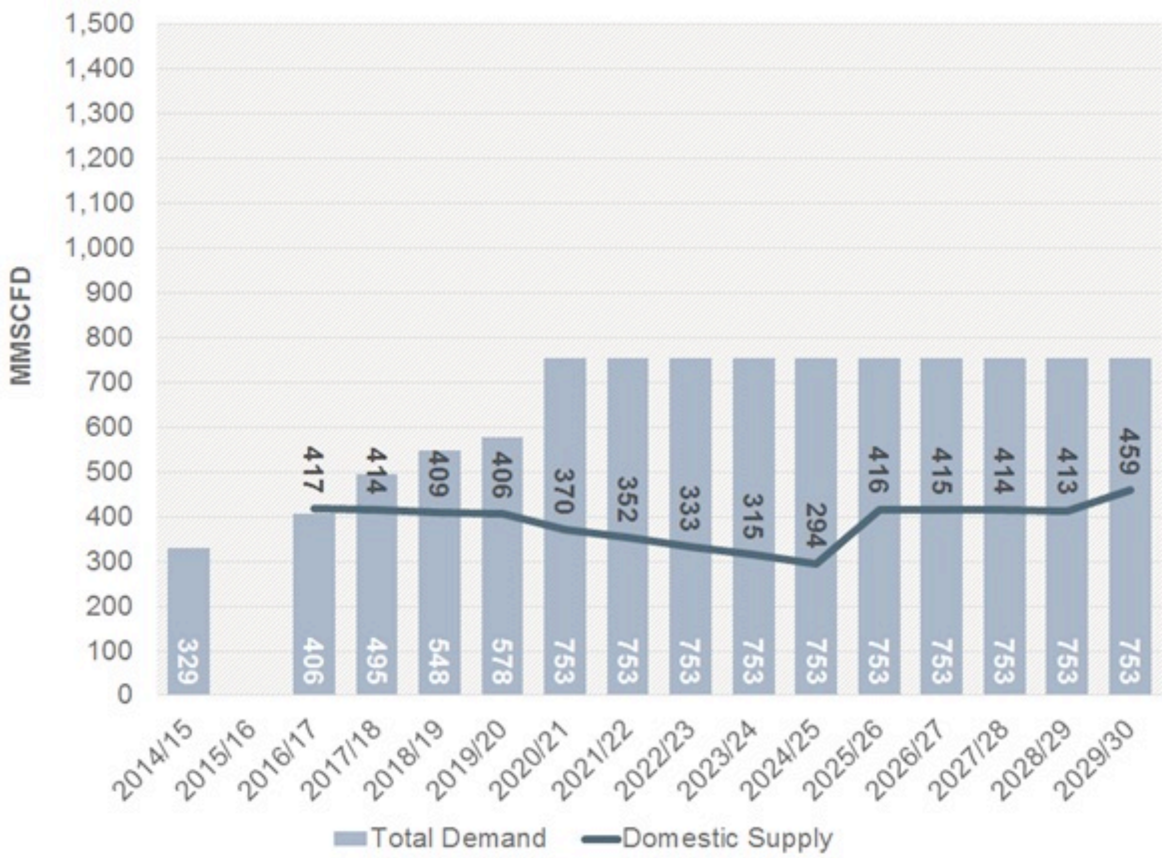
2026/27
2027/28
2028/29
2029/30
Total Demand
Domestic Supply

A.4 e.Gen 2016


MMSCFD
1,500
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2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
Total Demand
Domestic Supply

Section B Overview of the Project Team

B.1 MJMEnergy Limited

MJMEnergy is a UK-based firm providing technical and commercial consultancy throughout the world with a clear focus on natural gas and LNG related projects. Over the last few years MJMEnergy has advised on the commercial, operational and regulatory aspects of LNG imports throughout the world. In Pakistan MJMEnergy provided technical and commercial support to the GoP and SSGC (the incumbent monopoly), facilitating the first LNG imports into Pakistan via a FSRU. MJMEnergy has also advised on FRSU LNG import projects in Chile (ECL) and Ghana (VRA), working with ECL in developing Terminal-User-Agreements (TUA's) in Chile and an RFP for VRA in Ghana. MJMEnergy worked on a number of land-based LNG import projects in Greece, Singapore, the UK and the Netherlands. Finally, MJMEnergy recently published a major study of world LNG supplies, examining the current and future potential of LNG supplies from over twenty-eight different countries over the period 2015 – 2035. MJMEnergy also has a well-established training business providing capacity building to clients throughout the world, including LNG training to clients from one day overviews of the global LNG market through to five day courses on LNG economics, markets and modelling. In addition to the main team engaged with this project, we also have a strong back office team providing support to the project team in terms of project administration and technical support.

B.2 Penguin Energy Consulting Limited (PEC)

Penguin Energy Consulting (PEC) is a UK-based, independent energy industry techno-commercial consultancy and training provider. PEC has been involved in 46 LNG projects in 28 countries over 20 years, which has included onshore and offshore liquefaction and regasification facilities, small scale LNG, and peak shaving units. Project roles have included technology development, concept and feasibility studies, site selection, owner's engineer, commercial support, safety, environmental aspects and training. Penguin Energy Consultants Ltd has contracts and a relationship with the Society for Gas as a Marine Fuel for development of expertise and regulations concerning the use of natural gas, primarily as LNG, for marine fuel.

B.3 ECA

Economic Consulting Associates Limited (ECA) was formed in 1997 to provide economic and regulatory consulting services to industry and government. ECA's team and approach are based on many years' experience of carrying out economic and policy analysis, in the UK and worldwide. ECA specialises in advising on economics, policy and regulatory issues in the utilities industries, with particular expertise in the gas sector. The firm has a total of 20 professional staff members, based in offices in London, Bangkok, and New Zealand. All staff members hold qualifications in either or both of economics and engineering. ECA has undertaken over 450 assignments in over 50 countries around the world having worked with over 30 regulatory authorities and over 15 national utilities.

B.4 Drennan Marine Consultancy Ltd

Drennan Marine Consultancy Ltd is a LNG marine specialist with experience working in over 20 countries worldwide and is well used to ranking multiple locations in a structured and consistent way against relevant marine criteria including natural shelter, navigational risk and the capability of local services. As a qualified Master Mariner, Tom has a complete understanding of the needs and preferences of the LNG industry in terms of suitable LNG sites.