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NEW AND EMERGING LNG MARKETS: THE DEMAND SHOCK

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Executive Summary

Over the past decade, an increasing number of emerging markets has joined the liquefied natural gas (LNG) import club. From 7 countries in 2010, they were 17 in 2017: from traditionally export-oriented regions (such as the Middle East and North Africa) facing burgeoning gas and electricity demand, from emerging economies with growing energy needs (Southeast Asia), from countries facing severe energy and gas shortages and willing to replace imported oil in power generation (South Asia), and countries seeking greater energy security and diversification of gas supplies (South America). The flexibility and cost advantages of floating storage and regasification units (FSRUs), lower LNG prices since 2015, and financial support by LNG suppliers and multilateral financial institutions, have helped these countries to become LNG importers.

LNG demand in these new and emerging markets has surged since 2010, from 9 million tons (Mt) in 2010 to 41 Mt in 2017 (14% of market share), thus exceeding China's 2017 LNG demand, China being the most dynamic market on the global LNG market. This surge in new demand has made the anticipated LNG supply glut manageable and much lower than expected. The new and emerging markets are further growing with 16 countries planning to start LNG imports over the next five years.

Not all projects will materialize and the future LNG demand of new and emerging markets is difficult to predict. Main uncertainties include: price elasticity of this demand; the ability of governments to pay subsidies, or that of consumers to pay higher prices, especially when LNG is supplied to gas fired power plants; and trends in domestic gas production. For several existing and aspiring LNG countries, coal is still a major competitor to gas in the power sector. LNG demand from new and emerging markets is likely to create strong volatility in the market.

This new demand has been contributing to the rapid and profound changes which LNG markets are undergoing.

The LNG demand of new and emerging markets is quite different from that of established markets. One key physical feature of this demand is its counter-seasonality, with peaks in the summer months of the Northern Hemisphere, which may help to balance LNG supply and demand all over the year when the group expands further. The emergence of new buyers also brings challenges. Contracts in the new and emerging market are typically higher risk and for lower volumes and shorter periods than contracts in more established markets. As a result, it is difficult to leverage the demand from these markets to finance new liquefaction projects. Combined with the low LNG prices registered in 2015-2017, the lack of commitments on a long-term basis has stalled investment in new greenfield LNG export projects. This requires LNG producers and portfolio aggregators to adapt: grow, focus on the most competitive projects, become the long-term buyers of new LNG production that can be resold through their portfolios, focus on smaller projects and move down the value chain. To take advantage of rising demand in new markets, new LNG export projects will need to be low cost, more flexible and have creative pricing structures. LNG portfolio aggregators and traders will increasingly have to co-finance and develop LNG to gas projects.

In the short term, the current wave of LNG export projects ensures that LNG supply will remain abundant, although the market can be tight in winter periods as in 2017-2018. But without new sanctioned export projects, significant demand growth over the next decade will result in a global supply shortfall in the early 2020s.

Driven by the dynamism of this market, LNG demand in the new and emerging market may triple, or even quadruple by 2030. However, a supply crunch in the early 2020s, driven by a lack of new LNG export investments, would lead to higher prices and most likely, limit the increase in future demand and discourage a number of currently planned LNG import projects from being developed. The role of multilateral financial institutions in facilitating the set-up of new import capacity will be crucial, especially in a context where in many emerging countries the only alternative for baseload electricity still appears to be coal.

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Introduction

After its pause from 2012 to 2014, global LNG trade has expanded significantly since 2015 and boomed in 2017. In just three years, global LNG trade grew by 50 Mt to 290 Mt in 2017, absorbing a large share of the new LNG export capacity built during the same period. Some 60% of global LNG demand in 2017 was accounted for by China, Japan, South Korea and Taiwan, and a hugely disproportionate amount in the winter months. The heavy role of these importers in the supply/demand balance masks a less publicized trend: the rise of new and emerging markets since 2010.

Thirty-three countries are classified in this report as 'new and emerging' LNG markets (see Table 1). Among them, 17 countries are currently importing LNG (or feeding LNG to their market from their own LNG liquefaction facilities, e.g. Indonesia) and 16 countries have advanced projects to become importers. This new and emerging LNG market has grown significantly over the last few years, both in terms of number of countries as in terms of imported volumes. Only 7 countries imported LNG in 2010, while they were 17 in 2017. Their LNG imports have nearly quintupled since 2010, rising from 9 Mt in 2010 to 41 Mt in 2017 (14% of total trade), exceeding China's LNG imports that year. The compound average annual growth rate (CAAGR) of their LNG demand over the period, +25%, shows the dynamism of this new market.

The purpose of this report is twofold. Firstly, it aims to explain the main factors that have driven and enabled the rise of new and emerging LNG markets. Secondly, it aims to assess and qualify their future LNG demand. The report draws conclusions on the impact of their surging and specific LNG demand on global LNG trade and future supplies.

The report is broken down into five sections and seven annexes. The first section gives background information on recent supply and demand trends on the global LNG market. The second section provides detailed information about LNG demand in the new and emerging markets. The third and fourth sections look at the drivers and enablers of the rise of new and emerging markets. The fifth section assesses and qualifies future LNG demand in the existing and new emerging market. It also looks at the main features of this new LNG demand compared to that of established LNG markets. The conclusion gives final thoughts on the impact of the rise of new and emerging markets on global LNG supply and demand.

Regional analysis of the six sub-regions forming the new and emerging market in this report are included in annexes (Annexes 1 to 6). Annex 7 gives useful conversion factors.

Global LNG balance: China, USA and Australia are key drivers

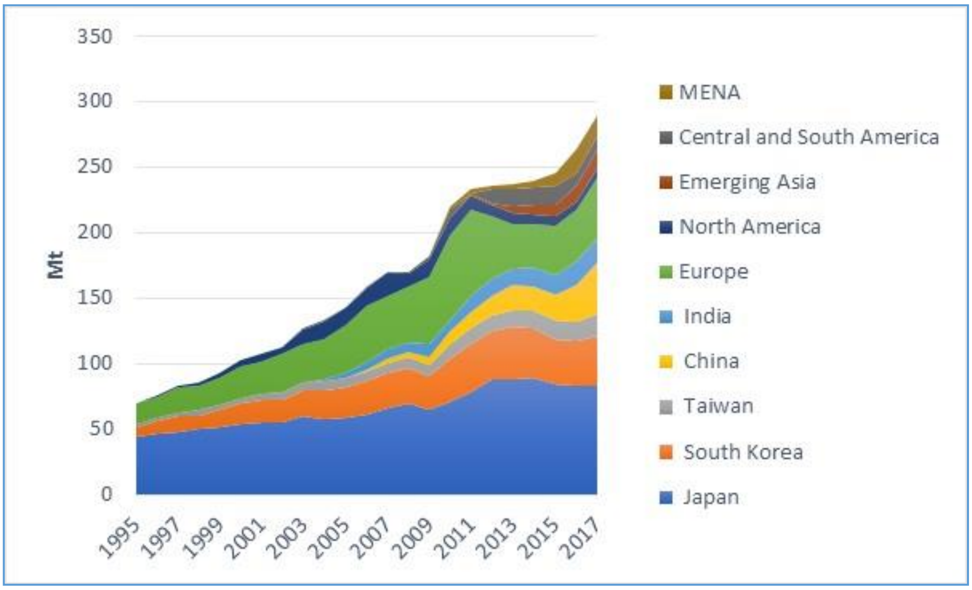
After its pause from 2012 to 2014, LNG trade has expanded significantly over the past three years and reached almost 290 Mt in 2017.[1] This is an increase of 10% compared to 2016 and the third consecutive year of growth. The Asia-Pacific region is the main demand centre for LNG consumption, accounting for almost three quarters of total LNG imports.

Most of the increase in 2017 is due to **a surge in Chinese and European LNG imports.** Imports by China increased by 42% in 2017 to 39 Mt, exceeded only by Japan's imports of 83.5 Mt. **China surpassed South Korea to become the world's second-largest importer of LNG**. The sudden and strong increase in Chinese LNG imports has been driven by government policies designed to reduce air pollution. The Chinese government has implemented policies to convert several million residential households in China's northern provinces, which traditionally rely on coal heating in the winter, to use natural gas-fired boilers instead. The new regulation led to growing imports in preparation of the winter season, reinforced by surging imports at the end of the year due to extreme cold weather in the winter season.

European LNG demand (including Turkey) continued to bounce back, with a 7.5 Mt (19%) year-on-year increase as gas demand increased. But as already observed in 2016, there was a divide between northern European countries, which decreased their LNG imports (-2 Mt) and Southern European states (including France), which registered a healthy 9.5 Mt growth. North American countries increased slightly their LNG imports, mostly due to increased demand in Mexico. South American importers stagnated, helped by higher hydropower generation and rising gas production in Brazil. The MENA region saw a decline in its LNG imports, mainly due to lower Egyptian imports.

1. International Group of Liquefied Natural Gas Importers (GIIGNL), *Annual Report 2018 Edition* (and previous editions), www.giignl.org; McKinsey, "The 2017 LNG Market in 10 Charts", McKinsey Insights, February 2018, www.mckinseyenergyinsights.com; Shell, *LNG Outlook 2018*, February 2018, www.shell.com.

Figure 1: Global LNG imports (1995-2017)



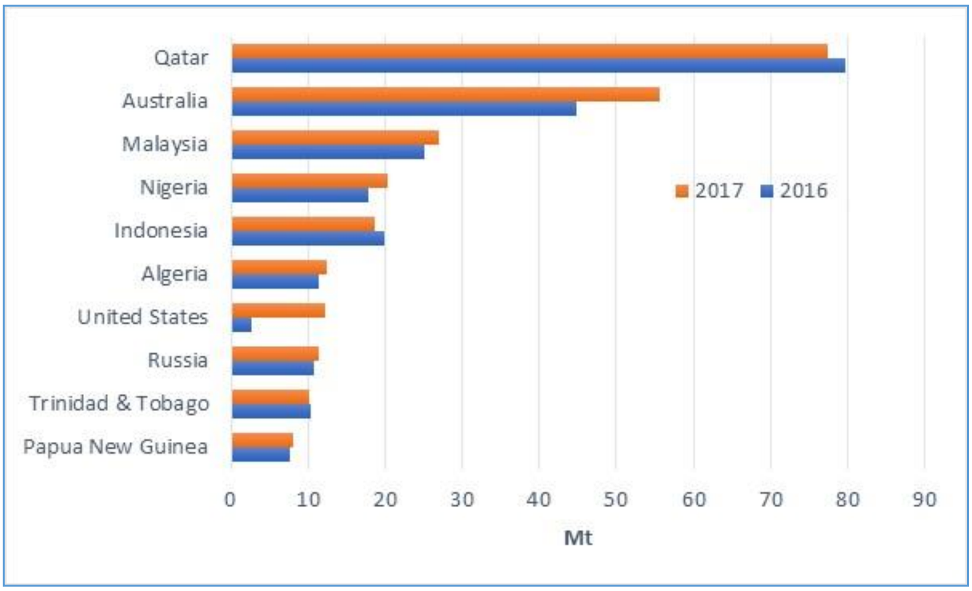
Source: Cedigaz LNG Service, GIIGNL 2018[2].

On the supply side, the global LNG export market has been dominated by Qatar, Australia, Malaysia, Algeria and Indonesia for the past 15 years. **The increase in LNG production in 2017 was mainly driven by the rapid growth of LNG production from both Australia and the US.** Together, they contributed an additional supply of 20 Mt. Boosted by new LNG projects commissioned in 2016 and 2017, Australian LNG exports rose by 24% in 2017 and a strong 26 Mt in the past two years. The US, which started exporting LNG in 2016,[3] became the seventh-largest LNG exporter globally (+10 Mt in 2017) and is expected to be part of the world's top three exporters by 2020. LNG production from Qatar, the largest LNG producer, was almost unchanged in 2017 at 78 Mt.

2. Cedigaz LNG Service, www.cedigaz.org (members only); International Group of Liquefied Natural Gas Importers (GIIGNL), *Annual Report 2018 Edition* (and previous editions), www.giignl.org.

3. If US Kenai LNG plant in Alaska is excluded.

Figure 2: LNG supplies – Top 10 exporters (2017 vs. 2016)



Source: Cedigaz LNG Service, GIIGNL 2018.

Since the end of 2014, **LNG export capacity has been expanding significantly** from 298 million tons per annum (Mtpa) to around 365 Mtpa at the end of 2017. Australia has led the growth in new LNG export capacity and is expected to become the first LNG exporting country by 2019, outpacing Qatar. The country has invested $200 billion in eight projects which will bring its total export capacity to 88 Mtpa by the end of 2018. Six of them were commissioned between 2015 and 2017, adding 45 Mtpa. The two remaining ones are Royal Dutch Shell's Prelude floating LNG project and Ichthys, led by Japan's Inpex. Together, the two new projects, along with the second train of Wheatstone project, will add 17 Mtpa by the end of 2018.

US export capacity, all from Cheniere's Sabine Pass liquefaction plant, reached 18 Mtpa at the end of 2017. Five additional LNG projects will bring US export capacity to 67.5 Mtpa at the end of 2020.

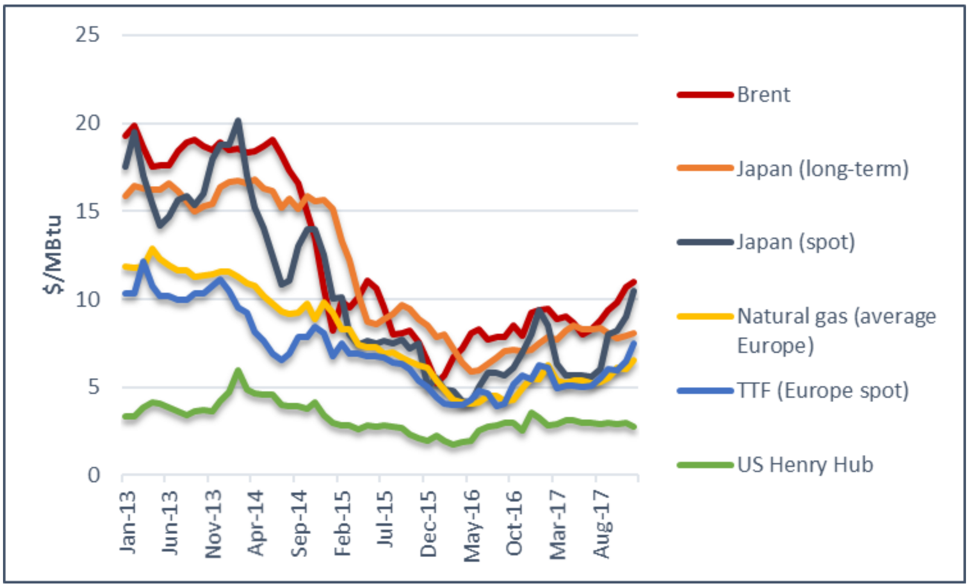
The first train of the Yamal LNG project in Russia has been commissioned at the end of 2017. When the three trains are completed by 2019, they will add 16.5 Mtpa. Smaller projects in Malaysia, Indonesia and Cameroon are adding additional export capacity.

Yet combined with the low LNG prices registered in 2015-2017, the lack of commitments on a long-term basis (20 years) has stalled investment in new greenfield LNG export projects. Just two LNG export projects took final investment decision (FID) in 2016 (Indonesian third train at Tangguh adding 3.8 Mtpa of export capacity and US Elba Island LNG, 2.5 Mtpa). Coral FLNG in Mozambique was the only project sanctioned in 2017 (3.4 Mtpa). FID for Equatorial Guinea's Fortuna LNG (2.2 Mtpa) has been postponed to 2018 as the completion of the project financing is taking longer than expected.[4]

The new wave of export capacity entering the market created strong expectations for a loosening LNG market. A supply glut was expected with demand unable to absorb this new wave of LNG supplies. However, rising demand from new and emerging markets and the unexpected acceleration of Chinese LNG imports had the effect of **tightening the market** in the fourth quarter of 2017.

Surging demand in China pushed international LNG prices up to their highest levels since 2014. **Spot LNG prices in Asia[5] doubled from $5/million British thermal unit (MBtu) in summer 2017 to $10-11/MBtu in winter 2017.**

Figure 3: Gas and LNG prices in major regions



Source: World Bank, Cedigaz LNG Service.[6]

4. LNG World News, "Ophir's Revenue Jumps as Fortuna FLNG FID Is Taking Longer than Expected", 7 March 2018, www.lngworldnews.com.
5. Platts Japan Korea Marker, "JKM, a Daily Physical Spot Price Assessment for LNG Cargoes Delivered into Japan and South Korea".
6. World Bank, "Pink Sheet, Commodity Markets", March 2018, www.worldbank.org; Cedigaz LNG Service, *op. cit*.

The tightening of the market in winter 2017-2018 mirrors the pressure already observed in winter 2016-2017, when high Asian demand had absorbed surplus LNG cargoes. Both winters saw international LNG prices higher than had been expected by most analysts. So far new demand appears to be absorbing the anticipated global oversupply, at least in winter months. Although markets have been tight during the winters, they have been much looser during northern hemisphere summers widening seasonal spreads.

The Emergence of New Markets

One of the most interesting aspects in the recent LNG trade is **the growing role of new but small LNG importers**. Thirty-three countries are classified in this report as ‘new and emerging’ LNG markets. Among them, 17 countries are currently importing LNG (or feeding LNG to their market from their own LNG liquefaction facilities, e.g. Indonesia) and 16 countries have advanced projects to become importers.

Some of them are not new, for instance, Argentina, Brazil and Chile started importing LNG in 2008 and 2009, but the dynamics of South American LNG imports is changing rapidly. For this reason, they have been included in this report in the new and emerging LNG market. This report looks at new pockets of LNG demand at regional level, and has not included Lithuania, Poland, Malta and the Canary Islands in the new and emerging market as their demand is grouped with European gas demand.

Table 1: New and emerging LNG markets

Region	Existing importers (as of beginning 2018)	Potential new importers in the short term (a)
Southeast Asia	Indonesia, Malaysia, Singapore, Thailand	Myanmar, Philippines, Vietnam
South Asia	Pakistan	Bangladesh, Sri Lanka
MENA	Egypt, Israel, Jordan, Kuwait, UAE	Bahrain, Morocco
Sub-Saharan Africa		Côte d'Ivoire, Ghana, Namibia, South Africa
South America	Argentina, Brazil, Chile, Colombia	Uruguay
Carribean and Central America	Dominican Republic, Jamaica, Puerto Rico	Barbados, El Salvador, Haiti, Panama

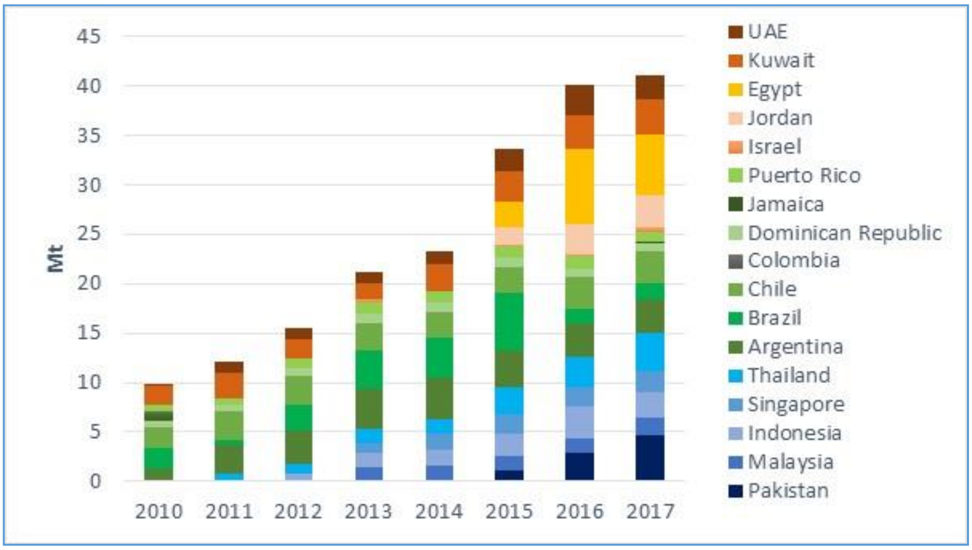
(a) Only countries with LNG import plans under construction or at an advanced stage have been considered in this report.

The new and emerging LNG market, as defined above, has grown significantly over the last few years, both in terms of number of countries as in terms of imported volumes. **Between 2014 and 2016, the 17 LNG importing countries from the new market segment accounted**

for three quarters of the net global LNG demand growth. Thanks to their surging demand, the LNG supply surplus has remained manageable and much lower than expected.

However, **the growth of their LNG imports has tapered off in 2017 with a modest increase of 2.3% over 2016.** The slowdown is mainly due to the decrease in Egyptian imports, one of the key driver in the surge of LNG imports of emerging markets, the stagnation of South American imports, where LNG imports are mainly driven by hydro conditions, and lower imports by the Middle East. Thanks to the discovery and fast-track commissioning of the Zohr gas field, Egypt is expected to stop LNG imports altogether by the end of 2018 (see below). No new country in the new and emerging LNG market entered the market in 2017, but Pakistan and Malaysia commissioned new LNG import terminals and the latest four comers (Pakistan and Jordan in 2015, Colombia and Jamaica in 2016) ramped up their LNG imports in 2017. Pakistan, notably, increased its LNG imports by 57% to 4.6 Mt in 2017.

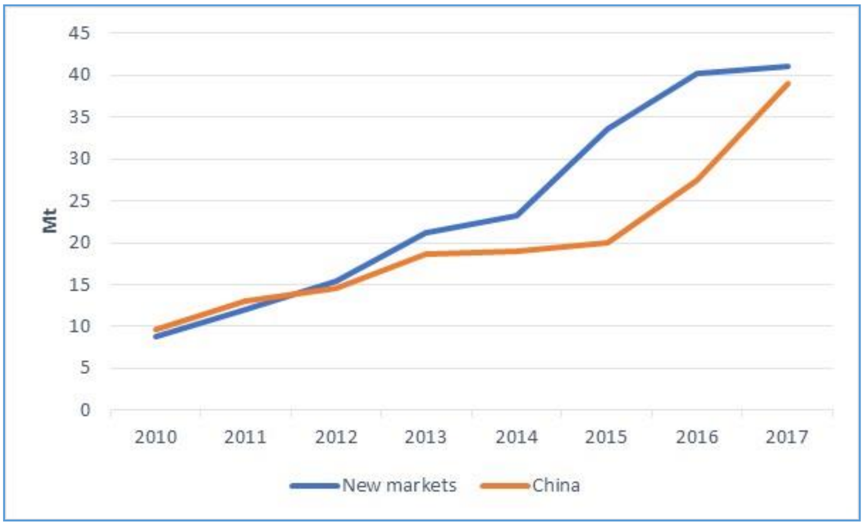
Figure 4: LNG imports by new and emerging markets (2010-2017)



Source: GIIGNL, Cedigaz LNG Service.

In order to better understand the significance of LNG demand of the new and emerging markets, Figure 5 compares their annual LNG demand to that of China, certainly the most dynamic importer in the global LNG market. The figure shows that, except in the past two years, the growth of LNG demand in the new and emerging LNG market exceeded that of China and, as a group, their imports are higher than those of China.

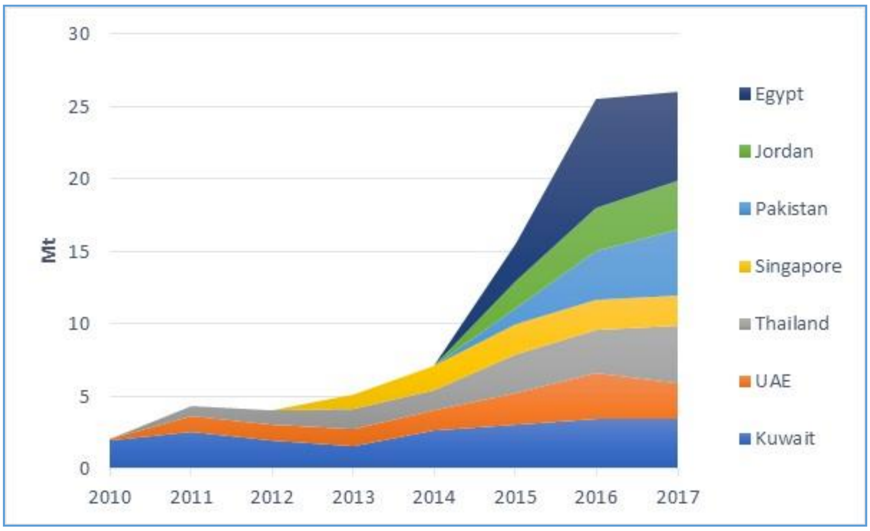
Figure 5: LNG imports in new and emerging markets versus China



Source: GIIGNL, Cedigaz LNG Service.

The growth of LNG imports in the new and emerging market since 2014 can be attributed to seven countries: Egypt, Pakistan, Jordan, Kuwait, the United Arab Emirates (UAE), Singapore and Thailand. All of them, except the Southeast Asian countries, have deployed FSRUs. FSRUs have been a key enabler for these countries to quickly access the LNG market (see below).

Figure 6: LNG imports in selected new and emerging markets



Source: GIIGNL, Cedigaz LNG Service.

Drivers of LNG Imports in Emerging Markets

The slowdown of the growth of LNG imports of new and emerging markets in 2017 questions the sustainability of their LNG demand. This requires understanding the main drivers of their LNG demand which can significantly differ from one country to another.

The key impetus for these countries to begin or increase LNG imports is to fuel economic and energy demand growth, especially electricity needs, to displace oil in power generation, to offset domestic gas production declines, to alleviate gas (and electricity) shortages, and to secure and diversify gas supplies.

Meeting growing gas demand

On the demand side, **the growth of natural gas demand in the power and industrial sectors** is the key factor behind the growth in LNG imports of emerging markets. This new demand is driven by **growing population, economic development, urbanization and industrialization trends**. In Southeast Asia, power demand has increased by a CAAGR of 6% over the period 2010-2016 and is expected to double by 2035.[7] With a population of 260 million, Indonesia is Southeast Asia's largest economy. Electricity demand growth, at around 9% per annum, is the highest in the region. The same trends are observed Pakistan, Bangladesh and the Middle East.

Oil-to-gas substitution, driven by the cost of oil-fired power generation, is a key driver of the boom of LNG demand in many emerging markets. In oil importing countries (Pakistan, Bangladesh), this substitution allows to reduce oil (and energy) import bills as LNG is cheaper than imported oil on a Btu basis (Figure 3). For oil exporting countries (the Middle East), the willingness to save oil for exports, in the form of value-added products, instead of burning it in power plants, is a major factor behind the growth in their LNG demand.

7. IEA, *World Energy Outlook 2017*, November 2017, www.iea.org (New Policies Scenario).

LNG also allows access to energy of populations who currently have no access to electricity (some islands in Southeast Asia or some potential LNG importers in Sub-Saharan Africa).

Offsetting temporary or permanent production declines

In several gas producing countries, **declining production has been a key driver for LNG imports.** Egypt moved from an LNG exporter to an LNG importer because its gas fields depleted quicker than expected. The new discoveries offshore the Mediterranean coast will allow the country to regain its exporting status. In the meantime, LNG imports have filled the gap between insufficient domestic gas production and growing demand. Current imports in the Middle East, South and Southeast Asia are also driven by insufficient domestic gas production in the face of growing demand needs. The case of Egypt shows that these demands can be fragile. The cost of LNG imports (even in a low-price environment) can provide a strong incentive to raise domestic natural gas prices allowing more investment in exploration and production (E&P). It also provides an incentive to reinforce energy efficiency efforts and lower gas demand. Indonesia provides another example of the versatility of LNG demand projections in emerging markets. The country has postponed its projections for net LNG imports to after 2020, thanks to the discovery and fast development of the Jangkrik gas field and lower LNG demand growth than expected.[8]

Meeting gas shortages and securing gas supplies

Meeting gas shortages and uncovered latent gas demand is a key driver of LNG imports in Pakistan and Bangladesh. The social and economic cost of unmet gas demand is high, costing as much as 2-3% of Bangladesh GDP, according to the World Bank.[9] Power outages in Pakistan were estimated to cost the equivalent of 7% of Pakistan's GDP annually.[10]

8. World LNG Shipping, "Indonesia Delays LNG Import Commitments", 24 January 2018, www.lngworldshipping.com.
9. World Bank, "Bangladesh: Ensuring a Reliable and Quality Energy Supply", 7 October 2016, www.worldbank.org.
10. IFC, "IFC Invests in Pakistan's First Liquefied Natural Gas Import Terminal to Boost Critical Energy Infrastructure and Spur Growth", 1 September 2015, https://ifcextapps.ifc.org.

Diversification and security of gas supplies is also an important factor to turn to the LNG market, notably in countries depending on gas imports by pipeline. The abrupt end of gas pipeline exports from Argentina after the '2004 gas crisis' provides one such example. Its neighbouring countries, notably Chile, had to quickly turn to LNG to compensate for the fall in gas supplies. The MENA region is another example where the stoppage of Egyptian gas exports by pipeline forced neighbouring importing countries (Jordan) to turn to the LNG market. The difficult geopolitical relationships between MENA countries is also a factor favouring LNG imports.

Security of gas and electricity supply constitutes a major driver for positioning FSRUs as the economic and political cost of gas supply disruptions or blackouts are generally much higher than the cost of the import projects/fuel purchases. FSRUs can therefore be seen as an insurance against gas supply shortages and electricity interruptions. They remain in place even with no or very limited imports (Colombia, Israel).

In South America, where power generation is highly dependent on hydro power, **LNG imports enable to secure electricity generation**. In 2014 and 2015, hydropower generation in Brazil declined due to a multi-year drought affecting several regions in the south-east and north-east of the country. This led Brazil to rise its LNG imports to secure electricity supply.

More and more, LNG will be used to back-up renewable intermittency. Gas and LNG demand is expected to increase to facilitate and complement renewable power generation, which is expanding rapidly in many existing and aspiring importing countries (e.g. South America, the MENA region).

Enablers of LNG Imports in New and Emerging Markets: FSRUs, But Not Only

FSRUs allow a growing number of countries to access the LNG market

FSRUs have been a game changer for the LNG market. They have enabled far more countries to become LNG importers and enabled them to enter the market far faster and at a substantially lower cost compared with building a conventional onshore receiving terminal.[11] They are a key factor behind the tremendous and fast growth of LNG imports in the new and emerging markets.

Box 1: FSRU: a mature and flexible technology

Offshore floating technology is not new to the petroleum industry. Floating production, storage and offloading (FPSO) vessels have been in operations for oil developments since the 1970s, proving instrumental in developing fields far offshore and in deep seas. As the LNG industry started to grow and demand mushroomed in new regions, floating technology began receiving attention. Gulf Gateway, the world's first FSRU import terminal, commenced operations off the coast of Louisiana in the Gulf of Mexico in March 2005. From 2008, use of the technology really started to take off.[12] Today FSRUs are considered a mature technology. At the beginning of 2018, there were 25 FSRUs in operation globally, operating as regasification terminals (the total fleet amounts to 30 vessels).[13] Floating import capacity was 95 Mtpa, accounting for 11.7% of the world's total capacity. In practice, not all floating terminals are FSRUs. Most are, but some facilities consist of a floating storage vessel (FSU) with a separate regasification unit that can either be afloat (FRU), such as in Bali, or placed on the shore, such as in Jamaica. Adriatic LNG, offshore Italy is a huge "Gravity Based Structure" looking more like an oil rig than a vessel.

11. DataFusion Associates, "FSRU's – The Great Game Changer", January 2017, www.energyinst.org.
12. IEA, *Medium Term Gas Market Report 2015*, May 2015, www.iea.org.
13. Cedigaz LNG Service, *op. cit.*

Neptune LNG, offshore Massachusetts, USA, consists of a dual buoy system where specially designed shuttle and re-gasification vessels (SRV) moor and discharge the gas into a subsea pipeline.[14]

The option of floating terminals is chosen by most emerging markets, which dominate the FSRUs market with 17 FSRUs and an import capacity of 74 Mtpa. FSRUs account for 69% of total import capacity of the new and emerging market. Out of the nine FSRU projects under construction, seven are in emerging markets, which also have 32 additional floating terminals under consideration.[15]

The success of FSRUs is explained by their specific advantages. Floating terminals can generally be brought online in a **shorter period of time** (less than one year for an existing vessel) and at a much **lower capital cost** (CAPEX) than onshore terminals, and also with **less permitting issues.** A typical new-build 170,000 cubic meters (cm) FSRU will cost in the order of $250 million compared with $1 billion for a similar sized conventional onshore terminal.[16] Another significant benefit is that the floating terminal can be leased, rather than developed and owned, thus substantially lowering overall project CAPEX.[17] This is an attractive entry point to the LNG market for many aspiring importers. The importer has not to finance the cost of the vessel itself, but only the associated infrastructure (the undersea pipeline to the shore or the jetty) to support the FSRU reducing its initial investment.

Another important advantage is the flexibility embedded in the technology. FSRUs can be moved and shipped elsewhere when a country that opted for an FSRU no longer requires the capacity (e.g. Egypt). They can be replaced with a larger unit when demand increases (as has happened in Kuwait and Dubai). They can also be a temporary solution enabling early imports of LNG whilst a larger onshore terminal is being constructed (e.g. Kuwait). They can also be diverted to different sites on a temporary basis, usually to address upswings in consumption during the peak demand season. FSRUs are therefore well adapted to cover seasonal needs. When not being utilized as an FSRU, the vessel can operate as a conventional LNG carrier providing additional flexibility.

14. DataFusion Associates, *op. cit.*
15. Cedigaz LNG Service, *op. cit.*
16. DataFusion Associates, *op. cit.*
17. Center on Global Energy Policy (CGEP), "They Might Be Giants: How New and Emerging LNG Importers Are Reshaping the Waterborne Gas Market", November 2017, Columbia/SIPA, http://energypolicy.columbia.edu.

While the CAPEX of FSRUs is lower than onshore LNG import terminals, operating expenses (OPEX), in contrast, are much higher due to the time charter associated with the vessel.[18] But **time charter rates have decreased over the past few years** and **the chartering period has become more flexible and shorter**. Charter periods were initially for 10-15 years, but 5 years are now the norm with short-term charters also possible. This is a key advantage in gas producing markets where uncertainty on future production makes imports necessary but only on a temporary basis. Three companies, Excelerate Energy, Höegh LNG and Golar LNG provide most of the FSRUs, but BW Gas, Exmar, Mitsui OSK (MOL), GasLog, OLT, Teekay LNG, Gazprom, Maran Gas and Dynagas have entered the market. With more competition in the market, time charter rates have decreased. While common rates were around \$150,000/d in 2015-2016, current rates are rather between \$100,000 to \$135,000/d, equivalent to \$36-50 million per year.[19] This has allowed more importing countries to enter the LNG market.

Therefore, for many prospective LNG buyers, FSRUs present a fast-tracked, flexible and competitive solution for procuring gas when compared with other gas procurement options such as onshore regasification or pipeline supply. Among the infrastructure-driven factors explaining LNG imports, the absence of regional gas pipelines is also contributing to growth in LNG demand, notably in regions where either the geography does not enable such infrastructure (Indonesia, the Philippines) or geopolitical issues make regional gas interconnections a sensitive issue (MENA).

The fast execution of FSRU projects means that LNG demand in new and emerging markets is much more difficult to predict as they can enter (or exit) the market very quickly (see below).

Ample global LNG supply and lower LNG prices

FSRUs are not the only enabler of the growth in LNG demand by new and emerging markets. **One of the main drivers has been the falling cost of LNG which has allowed it to compete with other fuels in many markets**. The collapse of oil prices after 2014 and the number of large LNG supply projects that have recently come on-stream have driven LNG prices steadily downwards, despite their recent recovery (see Figure 3). Asian spot LNG prices fell from an average of \$14.4/MBtu (and a high of

18. IGU, *World LNG Report, 2015 Edition*, June 2015, www.igu.org.
19. LNG World Shipping, "Have We Got FSRUs for You? Karen Thomas", July/August 2017.

$20/MBtu in January 2014) to only $5.72/MBtu on average in 2016, before rising to $7.12/MBtu on average in 2017. They nevertheless remain much lower than their heights in 2011-2014. **Rising supplies at lower prices have made LNG more affordable for a number of new consuming countries** and have created new opportunities for existing LNG importing countries. New emerging countries have also been attracted by increased spot trading in the recent years and changes in the contract frameworks towards greater flexibility. Suppliers have also become more willing to offer lower levels of oil indexation in contracts which has attracted emerging buyers. There has also been a diminishing attractiveness of coal-fired generation, one of the often-cheaper alternatives to gas-fired generation, largely due to environmental and economic considerations. The rise of coal prices since 2016 has eroded – but not eliminated – its competitiveness in several coal importing countries.

However, higher LNG prices, as observed during winter 2017-18, when prices rose to $10-11/MBtu, may compromise the growth of LNG imports in some emerging markets (see discussion below).

Supply push: rising role of portfolio players, traders and Southeast Asian national oil companies

Another key trend observed in new and emerging markets is the **growing role of a diverse group of investors in new LNG import projects**. While the first terminals built in emerging markets were almost all owned and financed by state-owned oil or gas companies (the exception being the terminals built in Chile), most new LNG import projects are promoted by **joint ventures between local companies** (often a state-owned oil and gas company or a power utility) **and LNG suppliers** (portfolio aggregators and state-owned LNG exporters, such as Qatar Petroleum), **trading houses, shipping companies** (such as Excelerate, Höegh, Golar), **and power plant suppliers** (Siemens, General Electric). In an environment of an expected LNG oversupply, many LNG suppliers and traders are willing to support the creation of new markets that can absorb part of their LNG volumes. By doing so, they support the development of these new markets and bring their financial strength and project management skills, which are lacking in several aspiring LNG importing countries. Key examples are Bahrain LNG,[20] Brazil's Sergipe and Açu 1 LNG-to-power projects[21] and Ivory Coast LNG in Côte d'Ivoire.[22] Pakistan and Bangladesh also illustrate the growing role of LNG suppliers, portfolio players and traders in emerging markets, not only for the supply of LNG, but also **as investors in LNG infrastructure**. Commodity traders Trafigura and Gunvor are investing in FSRUs in Pakistan and Bangladesh, a new business for these trading companies.

Among the LNG suppliers, a new trend is observed with **the rise of Southeast Asian state-owned companies** (e.g. Indonesia 's Pertamina, Malaysia's Petronas) **as investors in LNG import terminals abroad**. These companies have adopted new strategies to become global players on the LNG market and to develop new markets. They are faced with the end of contracts with legacy buyers and uncertain renewals (e.g. with Japan) and need to develop new outlets.

Although different by nature, **the role of Japan in emerging and new markets is growing**. The Minister of Economy, Trade and Industry (METI) has announced a $10 billion public-private initiative to support the expansion of Asia's LNG markets.[23] The combination of contractual over-commitment, slowing domestic demand growth and downstream market deregulation is encouraging Japanese LNG stakeholders to support demand growth in other Asian markets. Japanese trading and gas companies, equipment suppliers, including shipping companies, have investment plans in almost all proposed LNG import terminals in South

20. Bahrain LNG is financed and will be operated through a public private partnership, including Bahrain's oil and gas investment arm (nogaholding), Teekay LNG Partners, Gulf Investment Corp. (GIC) and Samsung C&T.

21. Centrais Elétricas de Sergipe S.A. (CELSE), a joint venture between Golar Power and Eletricidade do Brasil is developing an LNG-to-Power plant (Porto de Sergipe), which includes a 170,000 cm FSRU chartered for 25 years (Golar Nanook) and a combined cycle power plant of 1.5 GW. In March 2016 Exxon Mobil signed an LNG framework agreement to supply the Porto de Sergipe project, which has secured power purchase agreements starting in 2020. The project is potentially the first of three gas-fired power plants to be developed by CELSE at the site with a total capacity of 3,000 MW. Açu 1 LNG-to-power project is developed by Prumo Logística, part of the EIG Global Energy Partners, which has transferred the project to Port of Açu in the Rio de Janeiro state, where the company is looking to develop a gas and LNG hub. BP and Siemens are partners and investors in the Açu Gas Hub project, which includes up to three gas-fired power plants and an LNG regasification terminal at the port of Açu. The first power plant to be developed at Açu is the 1,238 MW Novo Tempo plant, expected to start construction in 2018.

22. In Côte d'Ivoire, the CI-GNL (Ivory Coast LNG) consortium was awarded the rights to build and operate an LNG re-gasification terminal in Vridi, Abidjan area, with a capacity of 3 Mtpa. The project involves Total, as operator with a 34% interest, Ivorian state companies Petroci (11%) and Société des Energies de Côte d'Ivoire (CI-Energies, 5%) as well as State Oil Company of the Azerbaijan Republic (Socar, 26%), Royal Dutch Shell (13%), Golar (6%) and Endeavor Energy (5%).

23. Platts, "Japan Offers $10 Billion to Support Asian LNG Growth", 18 October 2017, www.platts.com.

and Southeast Asia. Mitsui entered in the downstream market for the first time in 2017 when the company formed a joint venture with BW Group in Pakistan.[24]

One key absent from the market so far is China,[25] even in projects proposed in Sub-Saharan Africa, a region where Chinese investors have a strong presence in other energy sectors (e.g. coal-fired power plants). China's involvement in LNG import terminals abroad is limited to the participation of Chinese equipment suppliers to the building of proposed projects in Pakistan, Bangladesh, Indonesia, the Philippines and, to investment in LNG import infrastructure in Indonesia and Myanmar.

Multilateral financial institutions are also playing a key role in facilitating the setup of LNG import terminals in the new and emerging markets. The International Finance Corporation (IFC), a member of the World Bank Group, made an equity investment as well as provided a loan of up to $20 million to Engro Elengy Terminal Private Limited (EETPL) for Pakistan's first LNG import terminal. The Asian Development Bank (ADB) also provided financing for the terminal. The IFC also committed to provide up to $136 million in equity and debt financing to support the first FSRU project in Bangladesh.

LNG-to-power projects to rapidly add power capacity to the grid

In the face of continuing deficits across the world in power generation capacity, there is increasing consideration of **LNG-to-power projects as a relatively rapid way of adding significant capacity to the grid**. Most of the time, these LNG-to-power projects use FSRUs. Indeed**, for many aspiring importing countries, the lack of existing gas infrastructure - even sometimes the lack of a gas market - is an enormous challenge**. LNG-to-power projects hold the promise of alleviating power shortages or substituting more expensive oil-fired power generation and do not require a costly domestic gas transmission infrastructure – a jetty is enough. In theory, power plants provide the necessary firm gas demand to justify the LNG import project. The power plant also gives the necessary financial commitment to the project thanks to long-term power purchase agreements (PPA) signed with power utilities, either a state-owned entity or an independent power producer (IPP). In practice, aligning the financial and operational incentives and risks across

24. Mitsui, "Mitsui to Participate in Floating Storage and Regasification Unit (FSRU) Project in Pakistan", 14 November 2017, www.mitsui.com.
25. This does not take account of China's involvement in LNG export terminals.

stakeholders in both the regasification project and the power project is not always straightforward. Basically, two distinct LNG-to-power project structures have emerged:[26]

- First, the "fully integrated" financing structure whereby the FSRU/onshore LNG terminal and power plant are financed by the same group of lenders.
- Second, a "non-integrated" financing structure which envisages power plant sponsors obtaining financing for the power plant and FSRU sponsors separately raising financing for LNG project.

In non-integrated projects, one of the challenges is the co-development, and potential co-financing, of the LNG and power infrastructure. Not only do LNG to power projects potentially suffer from "project-on-project" risk due to the interdependency of the construction and commissioning of the gas and power infrastructure, but the project(s) are altogether more complex and require a number of additional risks to be considered and allocated, including potentially flowing various risks through a much longer project contract chain.[27] In these projects, if one element fails, all the project will fail. **Illustration of these challenges are demonstrated by the difficulties encountered by shipowners in Ghana**. Two LNG-to-power projects using FSRUs, although at an advanced stage, have not materialized because onshore infrastructure was not complete. The shipowners that had fixed FSRUs to the projects have had to be redeployed their vessels.

The integration of all elements of the project in one integrated project reduces the risk seen in non-integrated projects. The fully integrated projects, given the simpler structure, are most likely to move forward. The involvement of international LNG developers or aggregators and shipowners in a gas-to-power project is a key advantage due to their access to a portfolio of LNG supplies and FSRUs ready to be deployed.

More than 20 LNG-to-power projects using FSRUs are under consideration in new and emerging markets, potentially adding more than 30 Mt/y of new demand by 2023.[28] Many of the opportunities for gas-to-power are emerging across Sub-Saharan Africa. This is due to the region's deficit in generation capacity and the lack of gas grid infrastructure to support the development of conventional IPPs. Small

26. King & Spalding, *ibid*.
27. Ashurst, "LNG to Power Projects: Potential Opportunities on the Rise", Energy Source, Issue No. 17, August 2016, www.ashurst.com.
28. King & Spalding, "LNG-to-Power: Key Bankability Considerations for FSRU-to-IPP Project Structures", 27 March 2017, https://world.cwclng.com.

islands, such as the Caribbean or the Indonesian islands, are also hosts of a number of small-scale LNG-to-power projects. Several small-scale projects have already started or are under construction in the Caribbean which can provide a reference for innovative alternative logistic and commercial models used to establish such small-scale LNG supply chains.[29] Larger projects under construction or at an advanced stage include Porto de Sergipe and Açu in Brazil, Cilamaya and Bantaeng LNG-to-power projects in Indonesia. Among the advanced projects, FID is expected to be taken in 2018 for three LNG-to-power projects planned in Myanmar and for the Abidjan's LNG-to-power project in Côte d'Ivoire. It is worth noting, however, that most of the other projects in Sub-Saharan Africa have not progressed over the last few years, mainly due to lack of strong government support.

Despite the multitude of technical, legal, financial and commercial challenges facing LNG-to-power projects, creative approaches to project structuring can mitigate these problems, and, **as LNG-to-power projects become more widespread, such solutions may become commonplace**.[30]

29. OIES, "The Potential Market for LNG in the Caribbean and Central America", November 2017, www.oxfordenergy.org.

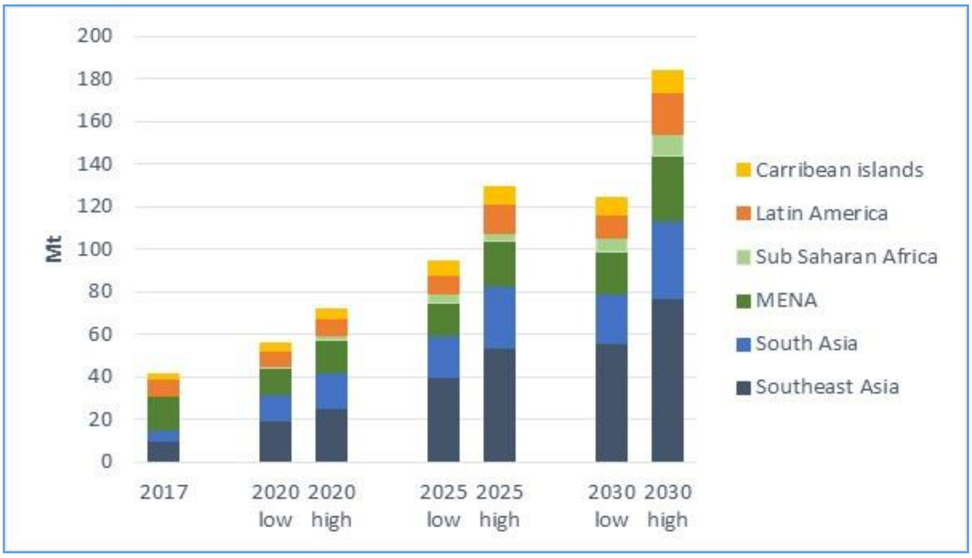
30. Center on Global Energy Policy (CGEP), "They Might Be Giants: How New and Emerging LNG Importers Are Reshaping the Waterborne Gas Market", November 2017, Columbia/SIPA, http://energypolicy.columbia.edu.

Outlook for LNG Demand in Emerging Markets

A surge in LNG demand

While individually, the outlook for LNG demand is relatively small in each new and emerging country, as a group, **their combined LNG demand is expected to surge in the medium and long term.** It may triple or even quadruple by 2030 to 124-184 Mt/year, making them responsible for about 30% to 35% of global LNG demand.[31] Their demand may exceed that of traditional Asian buyers. Japan, Korea and Taiwan imported 138 Mt in 2017 and their LNG imports are expected to remain flat or even decrease by 2030. Beyond the evolution of LNG prices, trends in domestic gas production in the new and emerging markets are a key factor explaining the wide outlook range.

Figure 7: Outlook for LNG demand in new and emerging markets



Source: Author based on OIES, Platts, WEO2017.

31. This is based on global LNG imports estimated at 450-500 Mt by 2030. The outlooks for new and emerging markets are based on the study published by the Oxford Institute for Energy Studies (OIES) (OIES, LNG markets in transition: the great reconfiguration, Oxford University Press, 2016), updated for some countries according to latest developments. The detailed outlook by region is presented in the annexes of this report.

The surge in LNG demand in new and emerging markets is due to the growing number of new importers and to rising LNG needs of existing and new importers, notably Pakistan, Bangladesh and Thailand. **From 2018 to 2023, nine countries are expecting to join the LNG import club:** Bahrain (2019), Bangladesh (2018), Côte d'Ivoire (2018), Myanmar (2021), Morocco (2023), Panama (2019), the Philippines (2019), Sharjah (2019), Vietnam (2023). Importing projects in the other seven potential new importers are either more speculative at this stage or less advanced.

Southeast Asia and South Asia are leading the growth. By 2030, the two sub-regions account for about two thirds of LNG demand in the new and emerging market, against 37% in 2017. Their rising imports will further reinforce the dominance of Asia in global LNG demand. These two regions are also responsible for much of the uncertainty in future LNG demand of the group.

In the short term, LNG imports of new and emerging market will be impacted by **Egypt's exit from the importing club**. Despite declining imports in 2017, Egypt was still responsible for 15% of total imports of the new and emerging market and 40% of imports of the MENA region. **Thus, LNG demand growth of the new and emerging markets may continue to slow down compared with the remarkable growth registered since 2010** (a CAAGR of 25%). Their LNG demand may increase by 15-31 Mt from 2017 levels to 56-72 Mt by 2020 (i.e. a CAAGR of some 10 to 20%). Much of the uncertainty in LNG demand in the short term is due to South Asia. Expectations for surging LNG imports by Pakistan and Bangladesh still need to be confirmed by infrastructure building and offtake agreements with creditworthy buyers. Provided that new LNG import capacity and transmission pipelines are delivered in a timely manner, Pakistan and Bangladesh's LNG demand could rise steeply in the short term and add 12 Mt of new demand by 2020 (see Annex 2).

Infrastructure is key to this remarkable growth. Some markets are already well positioned to increase their LNG imports, with LNG import capacity already well above their current imports. The import capacity of LNG terminals in new and emerging markets totalled 107 Mtpa at the beginning of 2018. Their utilization rates were above that of terminals in non-emerging markets: 45% in emerging markets against 35% at global level.[32] In addition, the emerging markets have 56 Mtpa of capacity under construction and some 140 Mtpa of planned capacity.

As expected, South and Southeast Asia dominates the existing and planned LNG import capacity. **It is also worthy to note that 65% of**

32. This is based on available capacity at the beginning of 2017.

projects under construction are FSRUs, which can quickly bring new demand.

Table 2: Existing, under construction and planned LNG import capacity in new and emerging markets

	Operating (Mt)	Under construction (Mt)	Planned (a) (Mt)
Southeast Asia	31.5	13.6	44.7-46.7
South Asia	10.9	18	43.3-43.4
MENA (b)	34.7	14.7	27.5
Sub Saharan Africa	0	0	8.1
Latin America	25	7.6	15-17.8
Carribean islands	5.1	1.83	0.9
TOTAL	**107.2**	**55.73**	**139.5-144.4**

(a) Major projects. Not all announced projects have a defined import capacity.

(b) The operating capacity includes 2 FSRU (10.1 Mtpa) in Egypt, to be removed shortly and one FSRU in Kuwait (5.6 Mtpa), likely to be removed when the permanent land-based LNG terminal is commissioned

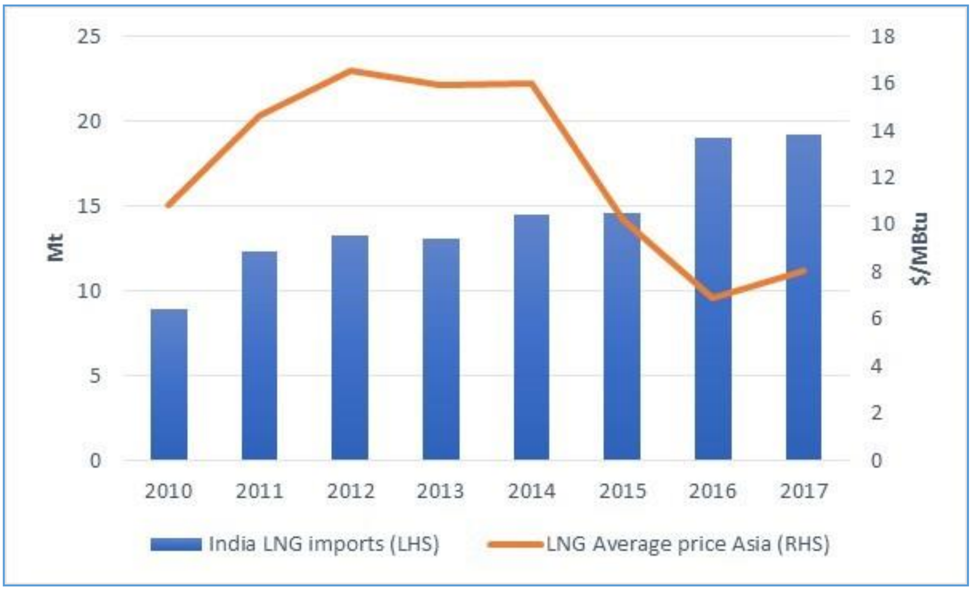
Source: Cedigaz LNG Service, Author (see Annexes for detailed information by project).

But LNG demand forecasts are challenging

One general observation is the difficulty to predict future LNG demand in the new and emerging markets. This is not limited to this group of countries. Projections of LNG demand in Europe and China are also a challenging exercise due to Europe's role as a balancing market, and the impact on LNG demand of sudden changes in regulation in China. But in the new and emerging markets, the exercise is complicated by the fact that **their natural gas demand is not well defined**. In several emerging markets, policy makers still need to clarify the role of natural gas in the energy and electricity mix. In several potential new importing countries, LNG demand depends on the materialization of LNG import infrastructure, which is difficult to predict. Due to these uncertainties, the range between the low and high LNG demand estimates by 2030 is quite large, with a gap of 60 Mt. South Asia illustrates this uncertainty. Both Pakistan and Bangladesh have considerable latent gas demand and have announced spectacular growth in their LNG demand to cover their gas shortfalls. However, the materialization of this potential gas demand needs to be confirmed by investments in import capacity, inland transportation infrastructure and long-term offtake agreements by creditworthy buyers. If customers are not able to pay international LNG prices, the uncovered demand has little chance to materialize.

One key issue is the price elasticity of this new demand, which has not been tested yet in the new and emerging markets. India can provide an illustration of the price elasticity of LNG demand. When average LNG import prices dropped by 33% to less than $7/MBtu in 2016, India's LNG imports rose by 30%. However, not all the increase can be attributed to lower prices as the Indian government adopted a financial mechanism which envisaged importing additional spot LNG in FY2016 to supply stranded gas power plants.

Figure 8: Elasticity of LNG demand: the example of India



Source: GIIGNL, World Bank.

The expectation of low LNG prices (around $5-6/MBtu) until the middle of the 2020s has certainly been a trigger for some importing projects. However, low prices are not sufficient to fully explain the attractiveness of LNG in emerging markets, which is driven by a combination of factors as seen previously. Many LNG import terminals were decided before the drop of LNG prices. The slowdown in the growth of LNG imports in 2017 cannot be interpreted as a move away from LNG. Firstly, it is mainly due the decrease in Egyptian imports. Secondly, higher LNG prices occurred after September 2017, when LNG imports by emerging markets usually fall. Pakistan did cancel two spot LNG cargoes when spot LNG prices rose. But still the country's LNG imports surged in 2017.

Determining the price required for growing gas demand in new markets is not straightforward and mainly depends on fuel competition in the importing market.[33] In many countries, LNG substitutes oil products in the power sector and this is the **relative level of LNG prices to oil products which is relevant, not the absolute level of LNG prices**. Pakistan provides an illustration of this situation. Most of its LNG demand is driven by the substitution of imported oil products in power generation. The use of LNG allows the country to reduce its energy import bill as its long-term LNG contracts are indexed to oil, meaning that as long as LNG substitutes imported oil, Pakistan saves on its energy import bill. Over the past two years, the country has saved some $1.7 billion on its energy import bill thanks to the substitution of imported oil products by LNG and better efficiency of combined gas cycle gas turbines (CCGTs) compared with oil-fired power plants.[34]

If the driver for LNG imports is to displace oil imports (Pakistan, Bangladesh) or save oil production to be able to export value-added oil products (the Middle East), LNG importing countries will be relatively indifferent to the price of LNG, provided that LNG is cheaper than oil. Long-term contracts indexed to oil with a low slope[35] guarantee LNG competitiveness. On the contrary, spot purchases will be strongly influenced by the relative level of spot LNG prices to oil prices. In countries where LNG is needed to secure electricity supply (e.g. Brazil), the price of LNG is not the determining factor. Brazilian LNG demand peaked during 2013-15 (despite high LNG prices in 2013) because of severe droughts and lower hydro production. In countries where LNG competes with coal in the power sector, a lower LNG price (typically below $6/MBtu) will be necessary to incentivize fuel switching. This remains valid despite the decline in LNG prices compared with their 2011-14 heights and the higher price of imported steam coal since 2016. This competition is mainly observed in Southeast Asia, but also in Pakistan.

Low LNG prices cannot be granted in the medium and long term, and even in the short term during the peak winter season. In the New Policies Scenario of the IEA, LNG import prices are projected to increase to around $10/MBtu for much of the latter half of the Outlook

33. See IEA, *World Energy Outlook 2017*, November 2017, www.iea.org.

34. Propakistani, "25% of Gas Demand is Being Met by LNG Imports", 1 August 2017, https://propakistani.pk.

35. The slope determines the responsiveness of the price of LNG to crude oil price fluctuations. A slope of around 17% equals full oil parity.

period (2025-40).[36] At such prices, the strength of LNG demand in the new and emerging markets will be tested. In most countries, despite recent efforts to reduce energy subsidies, the price of gas remains subsidized. When domestic gas prices are subsidized then it's not possible to pass through the cost of LNG supplies to the consumers. **One key question will be the ability of governments to pay rising subsidies** when LNG imports grow and/or LNG prices rise again. Alternatively, when subsidies are removed, the ability of customers to pay higher prices is questionable. For several existing and aspiring LNG countries, coal and renewable energy sources, especially solar that showcases constantly declining deployment costs, are major competitors of new LNG-to-power projects. In South and Southeast Asia, but also Sub-Saharan Africa, competition with coal projects (backed and financed by Chinese and Japanese entities) may alter future LNG demand. The capacity of governments to pay subsidies is limited and, in some countries, makes coal an attractive solution despite its environmental footprint.

Most of the new LNG importing countries procure their LNG supplies under a combination of long-term contracts and short-term or spot tenders. This allows them to adapt their gas procurement to the near market needs, but also to the volatility of LNG prices. The call on short-term contracts and spot purchases in several countries reinforces the uncertainty on their future LNG demand and **questions the strength of this demand if LNG prices durably rise above $8/MBtu.**

Another key source of uncertainty for future LNG demand in emerging markets is linked with the **development of domestic gas production**. LNG prices are higher than regulated gas prices for domestic production in several producing countries. The higher cost of LNG imports creates a strong incentive to raise these regulated prices. In turn, higher gas prices will stimulate investment in exploration and production (E&P), and may significantly reduce potential imports, or even eliminate the need to call on the LNG market in some existing and potential LNG importing countries. Gas producing countries with large untapped reserves are the most likely to exit the market quickly, as illustrated by Egypt. The UAE, for instance, may be able to become self-sufficient depending on the success of its diversification energy policy (Energy Plan 2050) and efforts to increase sour gas production. Projects for LNG imports in some Sub-Saharan African countries have been cancelled following the discovery of offshore gas reserves. The success of E&P efforts in some countries (e.g. Argentina) may even transform them in regional/global exporters and revive cross-border gas trade with neighbouring countries.

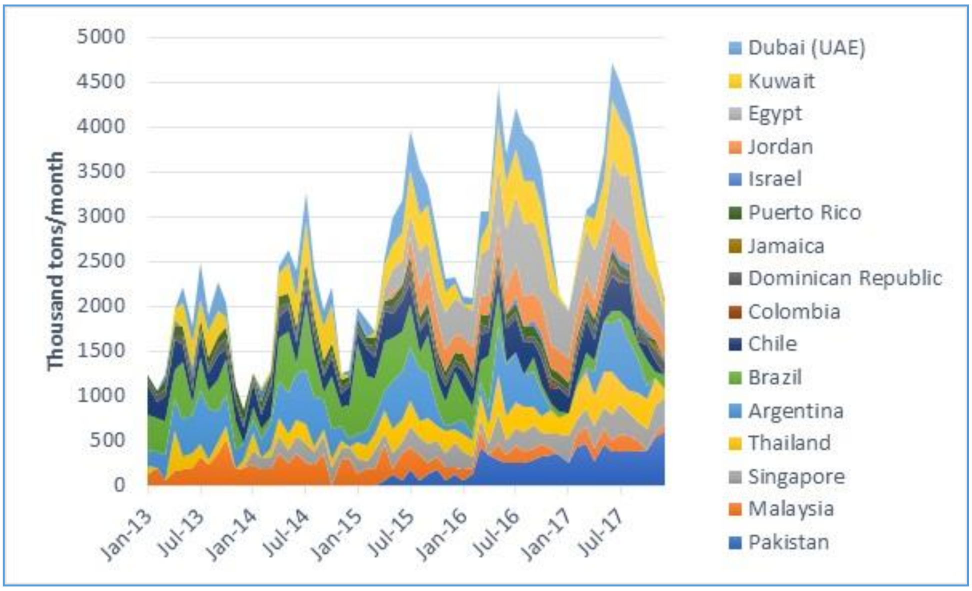
36. IEA, *World Energy Outlook 2017*, November 2017, www.iea.org.

Finally, **FSRUs, that are the favourite option in the new and emerging markets, also make their demand less predictable**. The fast execution of FSRU projects means that LNG demand can rise steeply in a very short time frame (e.g. Egypt, Pakistan). On the contrary, when supply and demand balances evolve, LNG needs can also decline rapidly. Most of the new vessels are chartered for short-term periods (5 years) and when chartered for longer periods, options are included to reduce the chartering period. Thus, the vessels can be removed relatively rapidly. Egypt is not an isolated case. Following the rise of associated gas production in the pre-salt basins and a more balanced supply, Brazil has reduced its LNG imports significantly and removed one of its three FSRUs.

Counter-seasonality of LNG demand

One key feature of LNG demand in the new and emerging market is its seasonality pattern. In most new and emerging LNG markets, LNG imports are concentrated in the peak summer months of the Northern Hemisphere. Either LNG demand responds to peaks in power generation due to air-cooling needs (Middle East), or to peaks in gas and power demand in winter months (June-August) in countries of the Southern Hemisphere.

Figure 9: Seasonality of LNG demand in new and emerging markets



Source: Cedigaz LNG Service.

This counter-seasonality is of utmost importance for the balance of the global market. LNG demand in the four key Asian importing countries (Japan, Korea, Taiwan and China) presents a high seasonality. Their LNG imports peak in the winter months of the Northern Hemisphere due to heating needs. Despite its high level of consumption, Asia has not developed a large underground gas storage infrastructure. Underground gas storage facilities are either quasi-inexistent due to geological difficulties (Japan) or still in their infancy (China). Asian countries therefore cannot manage the seasonality of their gas demand as it is done in Europe and North America which have developed large storage facilities to cope with seasonal fluctuations in gas demand. They therefore rely on other sources of flexibility to meet this seasonality. Storage at onshore LNG import terminals is widely used in the main Asian consuming countries. Japan and South Korea hold the world's largest LNG storage capacity (10.4 billion cubic meters (bcm) in gaseous form and 7.4 bcm, respectively). Chinese LNG storage capacity has also increased significantly since the country started importing LNG in 2006 (4.5 bcm at end 2017), although storage capacity is still a bottleneck in the country. Figure 10 compares the seasonality of LNG imports in the new and emerging markets to that of Japan, Korea, Taiwan and China. It clearly shows that **the emerging markets have played a key role – although not sufficient – to offset peak winter demand of the largest LNG buyers.** However, the weight of new and emerging market is still too small to compensate winter peaks of the largest buyers. With increasing LNG imports, the counter-seasonality of new and emerging markets is likely to play a rising role to smooth out seasonal price spreads on the global LNG market.

Figure 10: Monthly LNG imports in major Asian countries and new and emerging markets

Aggregated monthly data

Source: Cedigaz LNG Service, Author.

Different LNG requirements from established LNG markets

The emergence of new buyers brings financial and commercial challenges to LNG suppliers. North Asia has been anchoring demand for the past decade. North Asian buyers have signed long-term contracts with LNG greenfield projects, facilitating the building of these new export projects. The new and emerging markets are now expected to provide much of the growth in LNG demand. This demand looks very different, with more countries making up demand versus a few very large demand countries.

Contracts for lower volumes and shorter periods

Several (but not all) new and emerging countries have lower credit ratings than buyers in established LNG markets. Half of contracts signed in 2017 involved countries/buyers with no investment grades, compared with less than 10% in 2008.[37] **Their LNG purchase contracts involve lower volumes and shorter time frames**. Contracts signed during the past few years have already changed significantly because of the requirements of

37. Shell, *op. cit*.

these new customers. First, fewer supply and purchase agreements (SPAs) were signed as some new emerging markets (Latin America, Middle East) mostly rely on spot purchases. Second, the average contract length has decreased to typically 5 years, and third, the contract volumes are smaller than contracts signed by legacy buyers. Typically, new contracts involve 1 million tons per year (Mt/y), sometimes even less, for a duration of 5 years. Pakistan provides an illustration of this new contracting behaviour.

Box 2: Pakistan's LNG sourcing

Pakistan sources its LNG supply through a combination of long- and medium-term contracts and spot purchases. Pakistan State Oil (PSO) imports up to 4.5 Mt/y of LNG through term contracts with Qatargas and Swiss LNG trader Gunvor via the country's first LNG terminal, the FSRU Exquisite, commissioned in March 2015. The contracts are priced against international crude oil benchmarks. The 15-year contract with Qatargas is indexed to Brent oil price and has a 13.37% slope and no constant.[38] Imports to the second terminal are handled by Pakistan LNG Limited (PLL), a state-owned company created in December 2015 to manage Pakistan's LNG purchases, imports, storage, regasification and distribution. PLL has signed three term contracts with ENI (0.75 Mt/y for 15 years with a slope of 12.29%),[39] Shell and Gunvor (0.75 Mt/y each for 5 years). In addition, Global Energy Infrastructure Limited (GEIL) has signed a long-term contract for the import of 1.3 Mt/y of LNG with Qatargas. But the status of the contract is uncertain after the cancellation of the GEIL consortium's import project (see Annex 2).

Most of recent Pakistan's LNG requirements are sourced through buy tenders, including the SPAs signed by PLL in 2017 with Gunvor and ENI. PLL has also issued several tenders for spot purchases for its winter LNG supplies (four cargoes each month). But early January 2018, Pakistan cancelled two spot deliveries of LNG because of its rising cost. Pakistan expects to source its future LNG supplies through long-term intergovernmental agreements, complemented by spot purchases. The government intends to import an additional 3 Mt/y from 2018 under state-to-state agreements. In November 2017, the governments of Pakistan and Malaysia signed an intergovernmental agreement on LNG supply. The LNG supplies will be delivered by Petronas. In January 2018, Pakistan signed an intergovernmental agreement with Indonesia for 1-1.5 Mt/y of LNG from Pertamina. The agreement is for 10 years with a five-year extension. Pakistan is also negotiating with Russia for state-to-state agreements.

38. Platts, "Interview: Pakistan to Lock Another 3 Mt of LNG in Term Contracts by Year-End", 28 September 2017, www.platts.com.
39. PPL, www.paklng.com.

Table 3: Pakistan's term contracts from 2018

Supplier	Buyer	Volumes (Mtpa)	Duration	Start of deliveries	Pricing	Type of agreement
Qatargas (Qatar)	Pakistan State Oil	up to 3.75	15 years	2016	Oil indexed	SPA - Intergovernmental agreement
Gunvor	Pakistan State Oil	0.75	5 years	2017	Oil indexed	Open tender
ENI	Pakistan LNG Ltd	0.75	15 years	2017	Oil indexed	Open tender
Gunvor	Pakistan LNG Ltd	0.75	5 years	2018	Oil indexed	Open tender
Shell	Pakistan LNG Ltd	0.75	5 years	2018	Oil indexed	Open tender
Pertamina (Indonesia)	Pakistan LNG Ltd	1-1.5	10 + 5 years		Oil indexed	Intergovernmental agreement
Petronas (Malaysia)	Pakistan LNG Ltd	not available				Intergovernmental agreement
TOTAL		**7.75-8.25**				

Source: Author.

The Middle East mostly relies on short-term contracts complemented by spot purchases. Kuwait, which is building a permanent land-based import terminal, is expected to become a larger importer in the MENA region. Kuwait National Petroleum Company (KNPC) has indicated it would transition from short-term supply deals to contracts of up to 15 years and involving 6-7 Mt/y after 2020.[40] In December 2017, the company signed a 15-year LNG import deal with Shell International Trading for the purchase of 2 to 3 Mt/y, according to press reports, that will start in 2020.[41] Shell has supplied Kuwait with LNG since 2010 through medium-term gas contracts.

Latin America, which has highly variable LNG needs, depending on its hydropower production, mainly relies on spot purchases, although Chilean buyers have long-term contacts with Shell and Engie (the later will be transferred to Total).

Despite their rising needs, Southeast Asian importers have only covered a small share of their LNG demand through long-term contracts. The region has contracted less than 10 Mt/y on a long-term basis. The low contract coverage relative to their future needs points Southeast Asian buyers being increasingly important players in the short- to medium-term contract market, as the region is aiming to become an LNG hub (see below). There is a strong willingness in the region to move to more flexible LNG contracts, with no destination clause, and to shift away from oil indexation to LNG indices better reflective of supply and demand market conditions. However, in Thailand, the potentially-largest LNG market of the region, PTT Public Company Limited (PTT) mainly sources its LNG supply through long-term gas contracts (5.2 Mt/y) complemented by spot sales. Thailand aims to keep 70% of its future LNG purchases via long-term contracts, with the rest in the spot market.

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40. *The Arab Weekly*, "Kuwait Looks to Imports to Meet Natural Gas Needs", 24 July 2016, https://thearabweekly.com.

41. World Energy News, "Kuwait Signs LNG Import Deal With Shell", 26 December 2017, www.worldenergynews.com.

Contracts in most countries of the new and emerging market are typically of higher risk, for lower volumes and shorter periods than contracts in more established markets. As a result, it is difficult to leverage the demand from these markets to finance new liquefaction projects. The ample supply on the LNG market and intense competition between sellers (portfolio players, traders and national exporters) have so far enabled these countries to achieve shorter contract terms and better prices. But **several large-scale LNG export projects are stalled**, as contracts of only five-to-15 years aren't sufficient to secure approval for new greenfield LNG plants.

Box 3: A greater role for portfolio players and traders

The LNG purchasing behaviour and lower creditworthiness of some countries in the new and emerging markets gives an enhanced role to portfolio players and commodity traders. Portfolio players can manage these risks based on their portfolio approach. Commodity traders, which are eager to take more risks, are also major players in the new and emerging markets. Not only have they gained a large amount of LNG sales in emerging markets (e.g. Egypt, Pakistan), but they also invest in infrastructure in these markets (FSRUs in Pakistan and Bangladesh) and sign medium and long-term contracts with LNG producers. This brings a new class of medium and long-term buyers into the market at a time when fewer long-term contracts are signed. This comes as more traditional buyers are also reluctant to enter into new long-term contracts because of their commitments to increasing supply from projects in Australia and the US, and due to their uncertain LNG demand.

Recent greenfield projects have sold their entire LNG output to portfolio players and commodity traders: Gazprom Marketing & Trading has committed to buy 1.2 Mt/y for 20 years from Cameroon LNG; BP has bought the entire LNG output (3.4 Mt/y) of Mozambique's Coral FLNG for 20 years, and Gunvor has committed to buy the entire LNG output (2.2 Mt/y) from Equatorial Guinea's Fortuna LNG for 10 years.

The role of portfolio players will be key in future LNG supplies as these actors are able to organize their portfolio in terms of contract length and price formation to suit themselves and their buyers. LNG volumes marketed by portfolio players currently are, and are expected to continue being, the largest supply source in the LNG market.

Medium and long-term contracts indexed to oil

Pricing of medium and long-term contracts diverge among buyers in the new and emerging markets but are generally indexed to oil prices. Some countries in Southeast Asia (Singapore, which aims to be an LNG hub place), favour less rigid contracts and indexation on LNG indices. But generally, as many new and emerging markets seek to displace oil in power generation, the rise of their demand may help **maintain price linkages between oil and gas in the LNG market,** despite rising LNG exports from the US offering a different pricing structure.

Box 4: Singapore in the race to become an Asian LNG trading place

Singapore was the first country in Southeast Asia to offer open access to its Jurong LNG import terminal. The terminal offers LNG unloading, reloading, regasification and storage, as well as refuelling services. The terminal is developing breakbulk LNG shipments to allow small-scale delivery of LNG to small buyers in the region, mainly Indonesia and the Philippines. The high storage capacity of the terminal also allows the trading of LNG cargoes. The terminal imported 2.48 Mt in 2017 (almost unchanged from 2016) and re-exported 480,000 tons over the year, making Singapore responsible for 19% of LNG cargoes reloaded globally in 2017.

Singapore aims to become a regional hub for Asian gas trade by promoting the development of LNG trade on a spot basis and by developing a transparent LNG price index and financial tools to hedge LNG purchases. In its ambition, Singapore has the advantage of being strategically located in one of the world's busiest shipping waterways and home of a growing LNG trading community. But **compared with competing hub initiatives (Japan, China), Singapore's imports and infrastructure are small relative to the size of the LNG market in Asia Pacific.**

As the LNG market evolves, the role and relevance of spot and shorter-term contracts has increased. Spot and short-term trade now represents almost 27% of global LNG trade[42] and the share of small contracts becomes predominant. However, the industry lacked transparency and credible price references. Singapore has made concerted efforts to create price indices ('Sling indices') for spot LNG cargoes to boost regional pricing

42. GIIGNL, *op. cit*.

transparency.[43] In 2015, the Singapore's exchange (SGX) and Energy Market Company (EMC) started to publish a weekly price of spot LNG cargoes in the vicinity of Singapore, known as 'Singapore Sling'. It was followed by the publication of the 'North Asian Sling', which is a spot price for LNG cargoes delivered ex-ship (DES) to all ports in Japan, Korea, Taiwan and China, and by the 'Sling DKI', for spot LNG cargoes delivered to Dubai, Kuwait and India. In a further development step, in early 2016, SGX launched derivatives contracts (swaps and futures) for LNG trade. The availability of futures contracts on exchanges allow LNG buyers to financially hedge LNG purchases. The first transaction was made in January 2016 by commodity trader Trafigura and Singapore-based Pavilion Gas. In December 2017, an important milestone was achieved when SGX cleared the world's first futures contract for LNG delivered to Dubai, Kuwait and India based on Sling DKI.[44] However, despite significant progress, many hurdles remain, notably increasing the liquidity of the market.[45]

The rise of Asian LNG and power exchanges would challenge the dominant pricing model, in which price reporting agencies like S&P Global Platts' publish daily assessments based on bilateral bids, offers, and completed deals. An exchange's benefit is its transparent pricing information and ability to enable companies to hedge fuel costs by taking futures positions. The race between exchanges and commodity price agencies to become the region's leading price benchmark has intensified in 2017. So far, S&P Global Platts emerges as the winner. LNG swaps volumes, settled against its Japan Korea Marker (JKM) LNG price assessments, quadrupled in 2017 to 50,266 lots, equivalent to almost 10 Mt of LNG.[46] Despite the significant increase, the figure shows that the market is still in its infancy.

43. SGX LNG Index Group, www.emcsg.com.
44. *The Straits Times*, "Singapore Bourse Clears First Dubai/Kuwait/India Sling LNG Futures", 17 December 2017, www.straitstimes.com.
45. Channel NewsAsia, "Commentary: Singapore's Rising Natural Gas Ambitions Face Big Challenges", 24 January 2018, www.channelnewsasia.com.
46. CNBC, "ANALYSIS-Oil Like Gas: S&P Global Platts Bags Asian LNG Price Benchmark", 25 February 2018, www.cnbc.com.

Conclusion

The rise of new and emerging markets has been much welcome in the anticipated oversupplied market. This new demand has made the anticipated supply glut much lower than expected. But it holds a number of potential effects and alters profoundly the way LNG is financed and traded.

LNG demand from new and emerging markets is likely to create strong volatility in the market. Their LNG demand can surge and collapse quickly, as observed with Egyptian LNG imports. Their preference for shorter term and spot contracts reinforces this trend. These markets are responding to surging energy needs, but the amount of LNG they import will be dictated by price and infrastructure capacity. Governments in new and emerging markets have a wide range of challenges to address to ascertain the role of LNG in their energy mix.

In the short term, the wave of LNG projects, which are entering the market, mainly from Australia, the US and Russia, ensures that LNG supply will remain abundant, although the market can be tight in winter periods. But without new sanctioned export projects, significant demand growth over the next decade will result in a global supply shortfall in the early 2020s. Because of the substantial lead-time needed to bring online new liquefaction capacity (four to five years), it is essential that new investment decisions are made in the very near term. This means new long-term SPA must be signed now to enable FID in new liquefaction capacity so that this supply shortage and its resulting price impact can be avoided. The consequence of too low or too late investments in new export capacity would translate into higher LNG prices for all LNG buyers and would also limit or possibly stop the increase in demand from emerging markets. Among them, the more-price sensitive markets, Pakistan and Bangladesh, may have to review their ambitious LNG import plans downward and would miss the opportunity to cover their gas shortages with a cleaner fuel. It would potentially also deter new countries to sanction LNG to power projects.

To take advantage of rising demand in new markets with different requirements than established LNG markets, new LNG export projects will need to be quite different from the large greenfield projects developed so far, such as the Australian ones, backed by long-term contracts with established LNG buyers. The characteristics of LNG demand in new and emerging markets will require export projects to develop more flexible and creative pricing structures, and be prepared to offer shorter term agreements or a combination of short-, medium- and long-term LNG sales agreements.[47] A key issue will be to convince their financiers to provide financing on the basis of such offtake agreements, rather than the traditional long-term agreements with large, creditworthy utility off-takers. Project sponsors might have to develop merchant plants, thereby taking the risk of proceeding without long-term off-take agreements. Projects developed by oil majors, such as Total, Shell, ExxonMobil and Qatar Petroleum, which can provide equity into the projects will be favoured as it will be more difficult to get project financing. Due to the expected price sensitivity of new and emerging markets, project sponsors will have to reduce the costs of their projects and focus on the most competitive projects. Projects in Qatar and Papua New Guinea, which have the lowest costs of new supply, have the best chance of being the first to move forward, followed by proposals for small-scale, flexible new greenfield projects, in the US, which enjoy a large reserves base and lower risk project execution, and by proposed projects in East and West Africa, where the floating LNG (FLNG) technology is opening new offshore gas basins for LNG development.

47. Rigzone, "Views from the Crest of LNG's Second Wave: NextDecade's Kathleen Eisbrenner", 1 November, 2017, www.rigzone.com.

Annex 1 – Southeast Asia could become the fastest growing LNG demand centre

Southeast Asia, the world's third most populous region, is both a significant LNG exporter and a growing importer. The regional three LNG exporters, Brunei, Indonesia and Malaysia, exported 50 Mt of LNG in 2017, accounting for 17% of global LNG exports. The regional LNG importers, Malaysia, Singapore and Thailand, imported 7.8 Mt in 2017, up 22% over 2016. Indonesia also shipped 2.6 Mt from its exporting LNG plants in the western part of the country to its eastern gas markets.

Southeast Asian gas demand has increased rapidly in the 1990s and the beginning of the 2000s, driven by demographic, economic and industrial trends in the region. Growing electricity requirements resulted in a regional boom in gas-fired generation driven by the availability of domestic gas at low prices, very often subsidized. But since 2010, demand growth has slowed down (170 bcm consumed in 2016). The stagnation of regional gas production, at around 210-220 bcm/y over the past six years, has resulted in recurrent gas shortages, which have limited the growth in gas consumption. Thailand, Indonesia and Malaysia account for 80% of regional demand. The power (52%) and the industrial (48%) sectors are the main users.[48] Faced with stagnant production, the regional LNG exporters have reduced their exports. The region is still a net exporter, but its net exports are declining. Gas shortages have pushed Southeast Asian countries to diversify their electricity mix towards coal due to the availability of the fuel in the region and its relative lower cost than competing fuels, notably in Indonesia. Since the beginning of the 2010s, four countries have also turned to the LNG market to feed their growing gas needs, to address declining gas production and to secure their gas supply. Thailand was the first country in the region to import LNG in 2011, followed by Singapore and Malaysia in 2013. Since 2012, Indonesia has also become an LNG consumer through domestic LNG transhipments. Malaysia imports from the global market. The two LNG exporting

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48. IEA, *Southeast Asia Energy Outlook 2017*, November 2017, www.iea.org.

countries experience a geographical disparity between their domestic gas production and demand. Due to the complex geography of the two countries, they cannot opt for a nation-wide pipeline network. LNG offers the best solution to this logistics problem.

As of beginning of 2018, Southeast Asia had eight operating LNG importing terminals with a capacity of 31.5 Mtpa. Their utilisation rate was 34% in 2017. Thailand has one land-based terminal at Map Ta Phut, Rayong. Its capacity was doubled to 10 Mtpa in 2017. Singapore commissioned a land-based terminal at Jurong in 2013 with an initial capacity of 6 Mtpa, currently being expanded to 11 Mtpa. Singapore's strategic location and reputation as a global trading hub for other commodities place it at the forefront of becoming a significant Asian LNG trading hub (see Box 4). Indonesia has four LNG receiving terminals with an aggregate regasification capacity of 8.2 Mtpa. Malaysia has two LNG terminals with a combined capacity of 7.1 Mtpa. The country commissioned its second terminal in September 2017 in Pengerang in the southern Malaysian state of Johor. The terminal is expected to be used as an LNG hub and for trans-shipment operations.

The increasing development of LNG regasification terminals in Southeast Asia is also linked to the limited intra-regional pipeline infrastructure. Although there are ambitious plans to develop a regional natural gas grid, the Trans ASEAN Gas Pipeline (TAGP) project, current pipeline connections are quite limited: gas trade by pipeline in the broader region consists of Indonesia and Malaysia exporting gas to Singapore, and Myanmar exporting gas to Thailand and China.[49] Stagnation in gas production has led to decreasing pipeline flows, a trend which is expected to continue in the 2020s. Thus, the TAGP project has evolved since 2013 and now focuses on LNG and regional cooperation.[50]

According to the IEA, natural gas demand in Southeast Asia is expected to increase at a rate of 2% per year over the period 2016-40, a marked slowdown from the more than 6% per year over the past 25 years.[51] Gas demand is expected to grow from 170 bcm in 2016 to some 270 bcm in 2040. Most of the growth is expected to come from the industrial sector (especially the light industry branches). In the power sector, demand growth is constrained primarily because of the relatively high cost of gas compared with coal. As a result, the share of natural gas in Southeast Asia's power mix is expected to drop from nearly 45% today to just under 30% in

49. IEA, *Market Report Series: Gas 2017*, May 2017, www.iea.org.
50. IFRI, "L'énergie en Asie du Sud-Est. De l'intégration des réseaux à l'intégration des marchés", *Étude de l'Ifri*, January 2017, www.ifri.org.
51. IEA, *Southeast Asia Energy Outlook 2017*, November 2017, www.iea.org.

2040. Gas demand is expected to grow faster than production in the region, and net exports will gradually diminish. By the mid-2020s the region, as a whole, turns into a net importer of gas. This has important implications for infrastructure development in the region over the next decade.

Already, there is a growing interest in LNG imports in Southeast Asia. Three countries are looking to start LNG imports for the first time by 2019-2023 (Myanmar, the Philippines and Vietnam), and virtually all existing importers in the region are seeking to expand their imports. The expectation that the LNG glut would continue into the 2020s has created an incentive for Southeast Asian governments to accelerate energy reforms and support gas penetration in their downstream markets. FSRUs are facilitating this development, notably in the archipelago nations of Indonesia and the Philippines. Three new LNG import facilities and two expansions of existing facilities are currently under construction (13.6 Mtpa) and some 20 terminals, at various stages of planning, add some 45 Mtpa. Most new projects planned in the region are FSRUs.

Myanmar's government has decided to turn to LNG to cover its chronic power shortages and growing electricity demand. In January 2018, the government signed preliminary engineering works agreements with six international companies to build three integrated FSRU and LNG-to-power projects with a combined power capacity of 3,100 MW.[52] PPAs are expected to be signed in 2018, allowing the projects to be completed by 2021.

In the Philippines, the government intends to replace depleting natural gas reserves by LNG imports. An LNG hub project has been proposed in the Batangas province, south of Manila, initially with an FSRU to be commissioned by 2020, and later with a 5-Mtpa onshore terminal. In addition, there is one private terminal under construction in the south of Luzon Island, the Pagbilao LNG terminal.

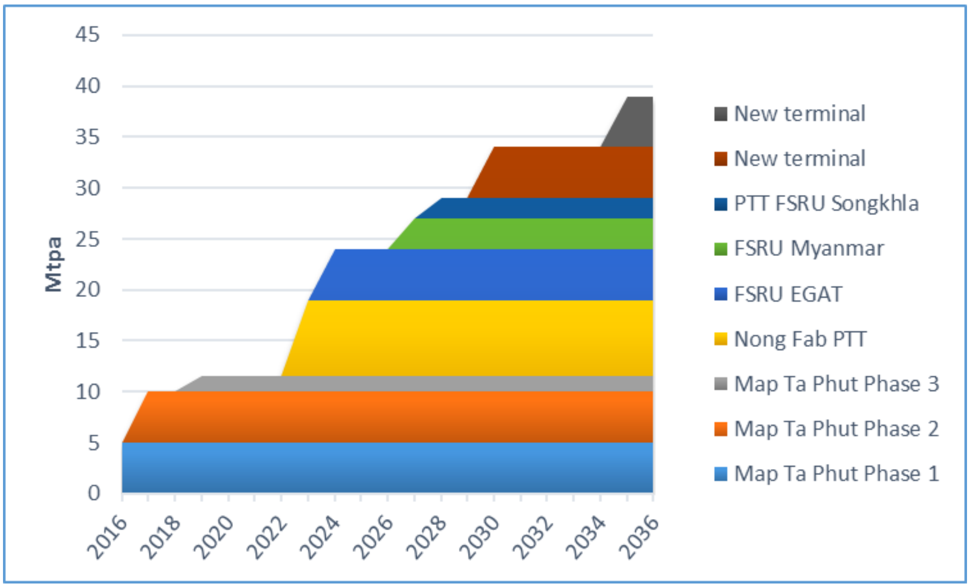
Vietnam wants to complement its domestic gas production by LNG imports and intends to start importing LNG at the beginning of the 2020s. The government has plans for two LNG terminals in southern Vietnam and expects both terminals to come online in 2023.[53] The terminals have planned expansions which could bring Vietnam's import capacity to 11 Mtpa.

52. Frontier Myanmar, "Does Myanmar's LNG Power Plan Stack Up?", 8 February 2018, https://frontiermyanmar.net.

53. Master plan on development of gas industry of Vietnam to 2025 with an orientation to 2035, August 2017, http://asemconnectvietnam.gov.vn.

In addition, Indonesia, Malaysia, Singapore and Thailand have additional import capacity under construction and planned. Thailand has by far the most ambitious plans. Government forecasts suggest a dramatic increase in LNG imports to 35 Mt by 2036.[54] To cope with the projected growth in imports, the country intends to boost its regasification capacity from 10 Mtpa currently to 39 Mtpa by 2036.

Figure 11: Planned LNG import capacity in Thailand



Source: Ministry of Energy, Author.

Indonesia is also increasing its LNG receiving capacity. Among the numerous projects under construction and planned in the country are the first LNG-to-power project linked with the government 35-GW fast-track program (Cilamaya in north-western Java) and the first privately-operated LNG import terminal (Bantaeng in South Sulawesi). The geography of the country and its energy demand, scattered over thousands of islands, means smaller LNG ships, small-scale regasification terminals and breakbulk LNG hubs will be required to deliver LNG to some of its future customers.

54. Ministry of Energy, "Thailand's Gas Plan, Roles of LNG in Thailand's Sustainable Energy Solutions", 26 June 2017, www.dmf.go.th.

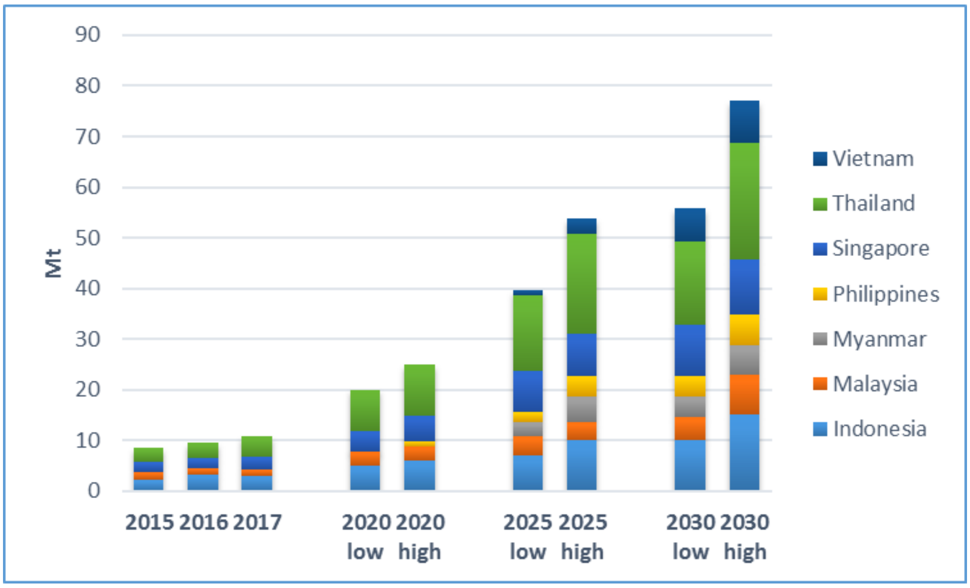
Table 4: Operating and major planned LNG import terminals in Southeast Asia

Country/Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
INDONESIA							
Nusantara Regas Satu	Jakarta Bay, West Java	Operating	PT Nusantara Regas	2012	FSRU	3	125
PGN FSRU Lampung	South Sumatra	Operating	PGN LNG	2014	FSRU	1.8	170
Arun LNG	Aceh	Operating	Pertamina	2015	Onshore	3	636
Bali FSU/FRU	Tanjung Benoa	Operating	Pertamina/PLN	2016	FSU/FRU	0.4	
Cilamaya FSRU (SHI new build)	Cilamaya, West Java	Under Construction	Pertamina, Marubeni, Sojitz	2021	FSRU	3	170
Bantaeng South Sulawesi LNG	South Sulawesi	Under Construction	Atlantic Gulf & Pacific (AG&P)/ENMP	2021	FSRU/FSU	1.1 (initial phase)	125
Cilacap FSRU	Central Java	Cancelled	Pertamina	2019	FSRU	Up to 1.6	
Batam LNG terminal	Batam	Planned	JFE/Medco Energi	2022-23	onshore		
Nebras Power Project	Northern Sumatra	Planned	Nebras Power	2019	FSRU		
Tokyo Gas - PT Bojonegara LNG	Bojonegara, Banten, West Java	Planned	Pertamina	2020	Onshore	3.8	
Gresik LNG terminal	Gresik, East Java	Planned	JIIPE				
Probolinggo	Probolinggo, East Java,	Planned	Australasia LNG		FSU	2.4	
MALAYSIA							
Melaka	Sungai Udang Port, Melaka	Operating	Petronas	2013	Offshore SRU	3.8	260
Pengerang LNG	Pengerang, Johor	Operating	Pengerang LNG	2017	Onshore	3.5	400
MYANMAR							
Kanbauk	Tanintharyi region	Under negotiation	Total, Siemens	2021	FSRU	2-3	
Shwe Thaung Yan	Ayeyarwady region	Under negotiation	Zhefu, Supreme Group, Gunvor	2021	FSRU	3-4	
Ahlone	Yangon region	Under negotiation	Toyo-Thai	2021	FSRU		
Made Island oil port	Offshore, west coast of Myanmar	Speculative	CNPC				
PTT FSRU2	Southern Coast of Myanmar	Speculative	PTT LNG	2027	FSRU	3 (up to 10)	
PHILIPPINES							
Pagbilao LNG	Pagbilao, Quezon	Under Construction	Energy World Corp.	2018	FSRU	3	130
Batangas LNG terminal (PNOC LNG hub)	Batangas, Luzon	Planned	Tbd	2020	FSRU (first phase)	5	
SINGAPORE							
Jurong	Jurong Island	Operating	SLNG	2013	Onshore	6	540
Jurong (expansion)	Jurong Island	Under Construction	SLNG	2018	Onshore	5	260
THAILAND							
Map Ta Phut	Map Ta Phut, Rayong	Operating	PTT LNG	2011	Onshore	5	320
Map Ta Phut (expansion)	Map Ta Phut, Rayong	Operating	PTT LNG	2017	Onshore	5	320
Map Ta Phut (expansion)	Map Ta Phut, Rayong	Under construction	PTT LNG	2019	Onshore	1.5	
Nong Fab	Map Ta Phut, Rayong	Planned	PTT LNG	2023	Onshore	7.5 (first phase)	
EGAT FSRU	Samut Prakan, Gulf of Thailand	Planned	EGAT	2024	FSRU	5	
PTT FSRU1	Jana District, Songkhla	Speculative	PTT LNG	2028	FSRU	2	
VIETNAM							
Son My LNG	Son My, Binh Thuan	Potential	PetroVietnam Gas	2023	Onshore	1.8	
Son My LNG (expansion)	Son My, Binh Thuan	Speculative	PetroVietnam Gas		Onshore	7.2	
Thi Vai LNG	Thi Vai, Ba Ria-Vung	Potential	PetroVietnam Gas	2023	Onshore	1	180
Thi Vai LNG (expansion)	Thi Vai, Ba Ria-Vung	Speculative	PetroVietnam Gas		Onshore	1	

Source: Cedigaz LNG Service, Author.

Southeast Asia could become the fastest growing LNG demand centre in the world. According to our analysis based on government and independent projections (Oxford Institute for Energy Studies (OIES), the Asia Pacific Energy Research Centre (APERC) and Platts),[55] the region could quadruple its LNG imports to some 40-54 Mt by 2025 (including Indonesian transhipments). LNG demand could rise further to 56 Mt to 77 Mt by 2030. At that date, Southeast Asia may account for 12 to 15% of global LNG imports.[56] The increasing import needs of the region will transform it from a nascent LNG importer into a major actor, the third one behind Japan and China by 2030. Thailand leads this rising trend due to its rapidly declining production. Indonesian LNG demand is expected to be supplied by domestic production over the next ten years and the country to turn into a net LNG importer in the second half of the 2020s. Singapore is expected to increase its LNG imports to compensate for the fall in gas imports by pipeline. Although their LNG demand is relatively small, the three new LNG importers will reinforce regional LNG demand.

Figure 12: Outlook for LNG imports in Southeast Asia



Indonesia is expected to source its LNG demand by its own LNG production until the mid-2020s.

Source: Author based on OIES, APERC, Platts.

55. Oxford Institute for Energy Studies (2016), "Asian LNG Demand: Key Drivers and Outlook, OIES", www.oxfordenergy.org; Asia Pacific Energy Research Center (2016), "LNG in Asia-Pacific - Favoring Trade and Rational Market Development, APERC", http://aperc.ieej.or.jp; Platts, "Dawn of a Global Commodity, LNG Trading Transformed", October 2017, www.plattsinsight.com.
56. This is based on an assumed global LNG trade of 450-500 Mt in 2030.

Annex 2 – South Asia: a quick entry into the LNG market

In South Asia, Pakistan and Bangladesh are emerging as a hotspot for LNG. Their potential demand is huge and competition for market share among LNG suppliers is intense. Pakistan started LNG imports in 2015 and already imported 4.6 Mt in 2017, up 57% over 2016. Bangladesh has joined the rank of LNG importers since the end of April 2018,[57] and Sri Lanka may follow later.

Demand for gas in Pakistan and Bangladesh has surged over the past few years due to growing population (193 million people in Pakistan and 163 million in Bangladesh), urbanization and industrialization trends. Their gas consumption totalled a combined 70 bcm in 2016. However, their gas production has not been able to cope with demand for gas, leading to growing chronic gas deficits and recurrent interruptions of supplies to power and industrial plants. Lack of investment in E&P has aggravated the gas deficit. Pakistan had a gas deficit estimated at 22 bcm/y in 2014, before the country started LNG imports, while the shortage is estimated at 6 bcm/y in Bangladesh. These unmet huge needs have hindered economic growth. To tackle the situation, governments in Pakistan and Bangladesh have set ambitious plans for LNG imports. The replacement of inefficient and costly fuel oil power plants is also a key factor behind growing LNG needs. Since 2010, to tackle chronic power shortages, Pakistan and Bangladesh had fast-tracked the construction of high-sulfur fuel oil and diesel power plants, increasing their needs for oil products imports and the cost of electricity. Since the collapse of LNG prices, they have drawn plans to import LNG to substitute their oil-fired power generation.

Pakistan's official forecasts suggest LNG demand could rise to as much as 30 Mt/y by 2022.[58] In Bangladesh, the government estimates that the country will consume at least 2 billion cubic feet per day (bcfd) (equivalent

57. Bangladesh has received its first cargo of LNG on board the Excellence FSRU, which arrived at the port of Moheshkhali on 23 April 2018.
58. Reuters, "Exclusive: Pakistan Sees Bigger LNG Profile; Imports to Surge by 2022", 10 July 2017, www.reuters.com.

to 15 Mt/y) by installing four FSRUs between April 2018 and June 2020.[59] According to the Bangladesh's Gas Sector Master Plan 2017, the country will need to import around 30 Mt of LNG annually by 2041 to meet the rising demand from various sectors including industries, power plants and fertiliser plants as domestic gas reserves are depleting fast.[60] To increase their LNG imports, the two countries have announced multi-million dollars investment into the necessary facilities needed for receiving LNG.

At the beginning of 2018, Pakistan had two operating LNG import terminals with an import capacity of 10.9 Mtpa. Pakistan's Engro Elengy LNG terminal came online at Port Qasim in March 2015, using Excelerate's FSRU Equisite. A second terminal, also at Port Qasim, began operations in November 2017, using BW group's FSRU Integrity. A third LNG import terminal at Gwadar, the Gwadar-Nawabshah LNG Terminal, was expected to be commissioned in 2018, but was shelved by the government in June 2017, although the terminal and associated gas transmission line could be reconsidered. Unlike these three terminals for which the government has guaranteed to buy the gas due to be imported, the subsequent terminals are going to be entirely private ventures with no government off-take guarantees. This makes the building of the next terminals more difficult. A planned FSRU at Port Qasim, promoted by a consortium involving the Turkish developer Global Energy Infrastructure Limited (GEIL), together with international energy groups, was cancelled in November 2017. Now, three proposed FSRUs are competing to bring additional gas to the country. If all built, they would increase Pakistan's LNG import capacity to 25.6 Mtpa by 2019. However, no FID has been taken yet.

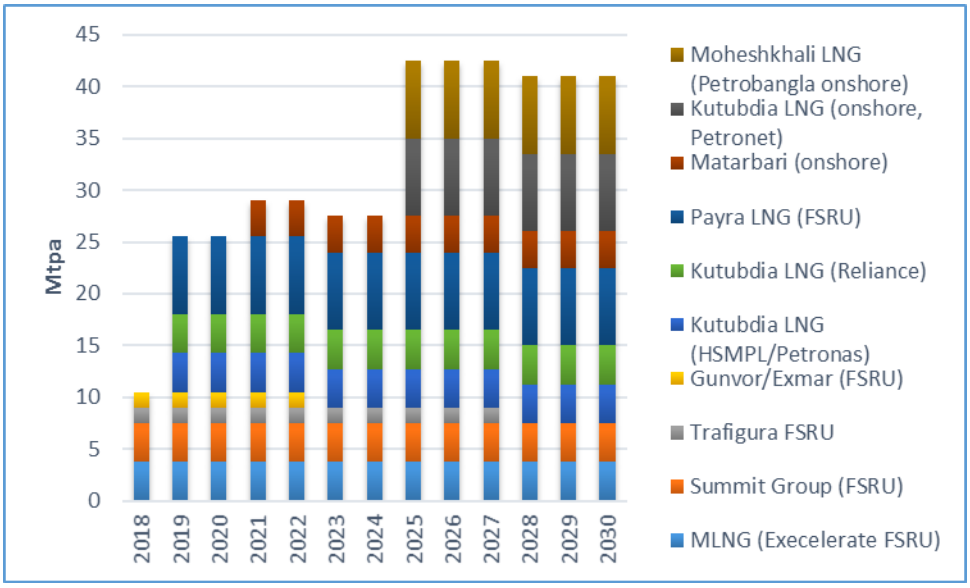
Bangladesh has ambitious plans to build out its LNG infrastructure. Both public and private import terminals are under construction and planned. Four FSRUs, located at Moheshkhali Island in the Bay of Bengal, are expected to start operations in 2018. The country's first LNG import terminal, a 3.75 Mtpa FSRU, developed by Excelerate Energy, started operations at the end of April 2018. The second terminal, also with a capacity of 3.75 Mtpa, developed by the Summit Group, is expected to be commissioned by October 2018. Two smaller FSRUs projects (1.5 Mtpa each), led by commodity trader Trafigura and by a joint venture of Gunvor and Exmar, are also planned to be ready by December 2018. With these four projects, Bangladesh expects to have 10.5 Mtpa of import capacity by the end of 2018. Two additional FSRUs are expected to be added in 2019

59. *Daily Sun*, "Govt to Review Progress of LNG Terminals, Power Plants", 22 November 2017, www.daily-sun.com.

60. Platts, "Bangladesh to Need 30 Million Mt/year LNG Imports by 2041", 24 August 2017, www.platts.com.

and Bangladesh has five other LNG import projects at different stages of planning. If all built, Bangladesh would have an import capacity above 40 Mtpa by 2025.

Figure 13: Advanced and planned LNG import terminals in Bangladesh



The chart includes planned, but not yet confirmed, FSRUs. The chart does not include the possible Sangu FSRU, not the recently-announced LNG-to-power project between Pertamina and Petrobangla/Bangladesh Power Development Board (BPDB), as no details are available yet.

Source: Author.

To cover their LNG needs, Pakistan and Bangladesh have signed SPAs with global LNG suppliers. Pakistan sources its LNG supply through a combination of long- and medium-term contracts with Qatar, ENI, Gunvor and Shell, complemented by spot purchases. Pakistan has also signed intergovernmental agreements with Malaysia and Indonesia and is negotiating with Russia (see Box 2). Bangladesh inked its first ever SPA with Qatar in September 2017 for 2.5 Mt/y of LNG for 15 years. State-owned Petrobangla is in negotiation with three other LNG suppliers and expects to finalize SPAs in 2018, bringing its total contractual LNG import commitment to 5.75 Mt/y from 2018. In addition, in December 2017, the government initiated two separate SPAs with Trafigura and the joint venture of Gunvor and Exmar to purchase 1 to 1.5 Mt/y each of imported re-gasified LNG from mid-2018. This would bring total contractual commitments to 8.25 Mt/y from 2018. Bangladesh also expects to complement its LNG imports with spot cargoes.

As LNG initially displaces imported gasoil and fuel oil in the power sector, the two countries have opted for LNG supplies indexed to oil prices for their term contracts. LNG priced at a low slope to crude oil guarantees the competitiveness of LNG.

Table 5: Existing and planned LNG import terminals in Pakistan, Bangladesh and Sri Lanka

Country/Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
PAKISTAN							
Engro, Excelerate Exquisite FSRU	Port Qasim, Karachi	Operating	Elengy Terminal Pakistan Ltd.	March 2015	FSRU	5.2	151
GasPort, BW Integrity FSRU	Port Qasim, Karachi	Operating	Pakistan Gas Port Company (PGPC)	November 2017	FSRU	5.7	170
GEIL consortium, Hoegh FSRU (HN 2909)	Port Qasim, Karachi	Cancelled	GEIL Consortium	2018	FSRU	5.4	170
Second Engro Terminal	Port Qasim, Karachi	Planned	Engro/Shell/Fatima Fertilizer/Gunvor	2019	FSRU	4.5	
Second Trafigura/PGPC Terminal	Port Qasim, Karachi	Planned	Trafigura/ PGPC	2019	FSRU	5.7	
Energas Terminal	Port Qasim, Karachi	Planned	Energas/Yunus Group	2019	FSRU	4.5	
Gwadar-Nawabshah LNG	Gwadar, Balochistan	Shelved	Interstate Gas Systems Ltd / CNPC	2020	FSRU	3.6	
BANGLADESH							
Moheshkhali LNG (MLNG)	Moheshkhali Island, Bay of Bengal	Under Construction	Excelerate Energy	April 2018	FSRU	3.75	138
Bangladesh FSRU (Execelerate FSRU)	Moheshkhali Island, Bay of Bengal	Under Construction	Summit Group	October 2018	FSRU	3.75	
Trafigura	Jetty of CUFC	Under construction	Trafigura	2018	FSRU	1.5	
Exmar floating barge	Jetty of KAFCO	Under construction	Gunvor and Exmar	2018	FSRU	1.5	
Sangu Platform		Unknown	Petrobangla		FSRU	small-scale	
Kutubdia LNG (Petronas)	Kutubdia Islands	Under Construction	HSMPL, Global LNG and Petronas LNG	2019	FSRU	3.75	
Reliance Bangladesh LNG Terminal	Kutubdia Islands	Under Construction	Reliance Power	April 2019	FSRU	3.75	
Payra LNG	Patuakhali, offshore Payra port	Planned		2019	FSRU	7.5	260
Matarbari	Matarbari, Cox's Bazar	Planned		2021	onshore	3.5	
Kutubdia LNG	Kutubdia Islands	Planned	Petronet LNG/PetroBangla	by 2025	Onshore	7.5	
Moheshkhali LNG	Moheshkhali Island, Bay of Bengal	Planned	Petrobangla	by 2025	Onshore	7.5	
Pertamina LNG-to-power project		Planned	Pertamina/BPDB/ Petrobangla	2021	FSRU		
SRI LANKA							
Kerawalapitiya	West coast	Planned	Petronet, Mitsubishi and Sojitz Corp	After 2020	FSRU	2.6-2.7	

Source: Cedigaz LNG Service, Author.

Looking forward, gas demand in Pakistan and Bangladesh is expected to grow significantly in the short term, but LNG faces several challenges that could constrain its growth in the medium/long term.

Among them, the ability to pay international LNG prices is a key challenge in these countries where the price of domestic gas has been kept low and where electricity tariffs are largely subsidized. In Pakistan, the government's inability to pay promised subsidies to power producers has caused "circular debt", known as inter-company arrears, throughout the supply chain. The accumulated debt has increased to $5.65 billion as of end 2017.[61]

In the power sector, LNG is in competition with coal and renewables. In Pakistan, the China Pakistan Economic Corridor (CPEC), intended to rapidly modernize Pakistani infrastructure, includes 10.4 GW of new power capacity to be built by 2020. Most of the projects are coal-based power plants, but there are also large hydro plants as well as solar and wind power plants. Already three coal power plants, each with 1.3 GW of capacity, have been commissioned. In Bangladesh, Indian, Japanese and Chinese governments are financing coal power plant projects.

Another challenge will be to complete transmission pipelines in time to transfer LNG to the main consumers. All planned LNG terminals in Pakistan are at Port Qasim, but the largest customers are in the north of the country, requiring large transmission pipelines to be built from Port Qasim to these northern markets.

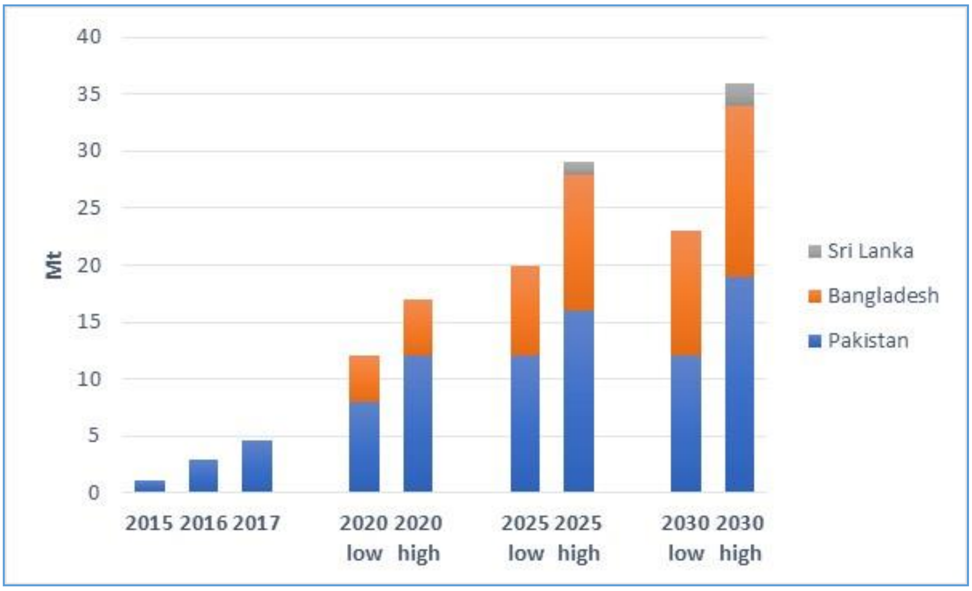
On the supply side, gas production is declining in both countries. However, little investment has been made in offshore E&P where some gas reserves could be tapped as the countries start opening their offshore acreage and offer better terms than in the past. In Bangladesh, the Gas Master Plan suggests rigorous exploration activities in onshore as well as offshore areas of the country, could raise gas supply by about 15 bcm/y.[62] In Pakistan, imports by pipeline may also constrain LNG imports in the 2020s. Cross-border gas pipelines from Iran and Turkmenistan have been studied for decades without success before being revitalized since 2015. Construction of the Turkmenistan-Afghanistan-Pakistan-India (TAPI) has started. Its commissioning date (officially in 2020) remains highly uncertain as the pipeline route is still plagued by security and financial issues.

61. Platts, "Pakistan Restricts Fuel Oil Imports as Consumption Falls", 2 January 2018, www.platts.com.

62. Platts, "Bangladesh to Need 30 Million mt/year LNG Imports by 2041", 24 August 2017, www.platts.com.

In conclusion, despite the considerable potential growth in LNG demand, infrastructural, financial, economic and geopolitical issues make the growth of LNG imports very uncertain in the medium and long term. After booming rates in the short term, the development of LNG demand could be constrained in the long term by competition from other sources in the power sector, domestic gas supplies and imports by cross-border gas pipelines. The ability to pay international LNG prices and the expected rise of LNG prices will be a test of the strength of South Asian LNG demand. Provided that new LNG import capacity and transmission pipelines are delivered in a timely manner, Pakistan and Bangladesh's LNG imports could rise steeply in the short term to 12-17 Mt by 2020. Post 2020, it is likely that the growth in LNG imports will slow down to 23-34 Mt by 2030. Sri Lanka, which has plans for the construction of an LNG regasification terminal near Colombo, could add up to 2 Mt/y of LNG demand by 2030.

Figure 14: Outlook for LNG imports in emerging South Asia



Source: Author based on OIES, Platts.

Annex 3 – Middle East and North Africa (MENA): LNG in competition with regional gas production

The Middle East and North Africa (MENA) region is the largest gas reserves holder in the world with 86.7 trillion cubic meters (tcm) of proven gas reserves at the beginning of 2017, equivalent to 97 years of current production. About two thirds of those reserves are located in two countries, Iran and Qatar. The region is a major source of LNG exports (104 Mt in 2017), but it has become a growing LNG importer due to gas shortages in some countries. The five regional importers (Egypt, Israel, Jordan, Kuwait and the United Arab Emirates (UAE)) imported 15.85 Mt of LNG in 2017, down 9% from 2016. This is the first annual decline since the region started importing LNG in 2009. The decline is in sharp contrast with the surge registered in 2016 when LNG imports jumped 77% on 2015 volumes to 17.43 Mt. The drop is mainly due to reduced imports by Egypt as the country is moving towards self-sufficiency.

Marketed gas production in the MENA region rose from 651 bcm in 2010 to 759 bcm in 2016, although there are wide differences among sub-regions: North African production decreased during the period, while the Middle East's production rose substantially, mainly in Iran, Qatar and Saudi Arabia. The region is highly dependent on gas, which accounts for 51% of its primary energy mix. Its gas demand has increased considerably in recent years due to infrastructure investments, population and economic growth, and price subsidies in several countries. Gas demand rose from 478 bcm in 2010 to 600 bcm in 2016.[63] While the MENA region is rich in gas, in some countries, domestic production has not been able to cope with rising gas demand for power and industry, resulting in gas shortages. The trend has been reinforced by the difficulty to raise domestic production from non-associated gas fields. Pipeline gas imports have helped to offset gas shortages. The UAE and Oman have received Qatari gas from the Dolphin pipeline since 2008. These flows have been unaffected by the current Gulf crisis. Egypt exported natural gas by pipeline to neighbouring

63. IEA, *Market Report Series: Gas 2017*, May 2017, www.iea.org.

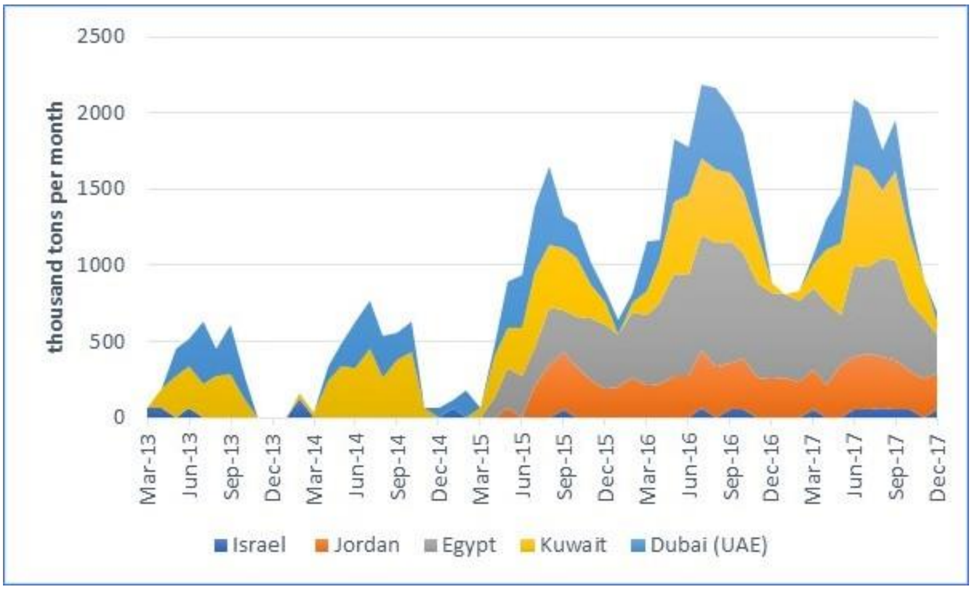
countries. However, this cross-border trade ceased completely in 2014 when Egypt redirected gas to its own market. Thus, several MENA countries have turned to the LNG market to secure their gas supplies and meet their growing gas demand.

Kuwait was the first country in the region to start importing LNG in 2009 to meet its gas shortages, first using the Excelerate Explorer FSRU, which was replaced in 2014 by the larger Golar Igloo FSRU. Dubai followed in 2010 with the Golar Freeze FSRU, later replaced by the larger Excelerate Explorer FSRU. They were joined in 2012 by Israel which chartered the Excelerate Excellence FSRU to secure its gas supplies pending the development of its offshore gas fields. Jordan was forced to quickly turn to the LNG market due to the collapse of Egyptian gas exports. The country took delivery of its first LNG cargoes in 2015, having chartered the Golar Eskimo FSRU. In the same year, Egypt chartered two FSRUs (Höegh Gallant and BW Singapore) to cover its gas shortages. Plans to charter a third FSRU were put on hold at the end of 2016, after the discovery of the large offshore Zohr field. Abu Dhabi joined the LNG receiving countries by chartering the Excelerate FSRU in 2016 to respond to short-term peak needs and optimization of gas flows at its Das island's LNG liquefaction facility. In view of this, plans to build a 9-Mtpa land-based terminal at Fujairah have been put on hold.

All current operating terminals in the region use FSRUs. FSRUs are well positioned to cater temporary gas shortages in the region, while it develops either permanent onshore terminals (Kuwait) or new sources of gas (Egypt). The seven FSRUs moored in the region provide the ability to regasify up to 34.7 Mtpa of LNG. The fleet achieved a combined 46% utilisation rate in 2017.

So far, MENA importers have tended to confine imports to the peak air-cooling months of April-September and their LNG imports are highly seasonal.

Figure 15: Seasonality of LNG imports in the MENA region



Source: Cedigaz LNG Service.

New countries in the Middle East are going to join the LNG import club. Bahrain and Sharjah are set to become the next two LNG importers. Bahrain is building an LNG import terminal (FSU/FRU) with a capacity of 3 Mtpa initially, which could be increased to 6 Mtpa, if needed. Sharjah plans to use an FSRU with a capacity of up to 1 bcfd (7.5 Mtpa) to end chronic shortages of gas and provide sufficient capacity to supply the entire Northern Emirates and spare capacity for future demand. The first permanent land-based regasification terminal in the region is currently under construction in Kuwait at Al Zour, and when it is commissioned at the beginning of 2021, it will replace the current FSRU. The terminal has an initial capacity of 11.7 Mtpa, which can be doubled.

In North Africa, in order to meet the growing demand for electricity and address variability issues arising from the significant expansion of variable renewable energy, Morocco has decided to diversify its generation mix by increasing the use of gas, based on LNG imports. The Kingdom has launched an ambitious gas-to-power project including the construction of an LNG terminal with an import capacity of 7 bcm/y (5.3 Mtpa) at Jorf Lasfar, two CCGT power plants (one at Jorf Lasfar and the other at Dhar Doum) with a combined capacity of 2,400 MW and a 400 km gas pipeline to connect the LNG terminal to the Maghreb-Europe Pipeline (GME) pipeline. The gas-to-power project is estimated to be in the region of a $4.6 billion investment.[64] Morocco's LNG needs, estimated at 5 bcm/y

64. White & Case, "Morocco – Gas to Power Project", 31 May 2017, www.whitecase.com.

should meet 13% of the country's energy needs by 2025, compared with 6% currently. Morocco's tender for the LNG-to-power project will take place in 2018, and LNG imports are expected to start in 2023. Morocco has also plans to convert oil-fired power plants to gas, as well as building additional CCGTs, and, according to non-official reports, could start importing LNG by 2021 through a 2-Mtpa FSRU.

Although no plans for LNG imports by Saudi Arabia have been announced, the conversion of its oil-fired power plants to natural gas as envisaged in its Vision 2030, combined with the huge development of its industrial and petrochemicals industry, makes the Kingdom a good candidate for future LNG imports. This is despite the expected huge growth in Saudi gas production. Among other potential LNG importer in the region, Oman has announced plans to add an FSRU to optimize its gas supply. However, no concrete plan has emerged so far.

Terminals under construction and planned in the MENA region have a combined capacity of 42.2 Mtpa (with expansions). But Egypt is exiting the LNG import market. Thanks to the fast track development of the Zohr and West Delta fields, Egypt has announced that it will stop LNG imports by the end 2018.[65] Taking into account the removal of the FSRUs moored in Egypt and that of Kuwait when its land-based terminal is commissioned, MENA import capacity would total some 41 Mtpa by 2021, with most of the increase coming from the new terminals in Kuwait and Bahrain. It would rise to 46.5 Mtpa by 2023, when the Moroccan land-based terminal starts operation.

65. *Arab Finance*, "Egypt to Stop Importing Gas by End-2018: EGAS", 20 December 2017, www.arabfinance.com.

Table 6: Existing and planned LNG importing terminals in the MENA region

Country/Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
BAHRAIN							
Bahrain LNG	Khalifa Bin Salman Port	Under construction	Bahrain LNG	2019	FSU/FRU	3-6	174
EGYPT							
FSRU - Hoegh Gallant	Ain Sokhna	Operating	EGAS	2015	FSRU	4.3	170
FSRU BW Singapore	Ain Sokhna	Operating	EGAS	2015	FSRU	5.8	170
ISRAEL							
Hadera Deepwater LNG - Excelerate Expedient	Hadera, Haifa	Operating	INGL	2013	FSRU	1.9	138
JORDAN							
Jordan LNG - Golar Eskimo	Gulf of Aqaba	Operating	NEPCO	2015	FSRU	5.6	160
KUWAIT							
Mina Al Ahmadi - Golar Igloo	Mina Al Ahmadi	Operating	KPC	2014	FSRU	5.6	170
Kuwait Permanent LNG Import Facility	Al Zour	Under construction	KPC	2021	Onshore	11.7	720
Kuwait Permanent LNG Import Facility (expansion)	Al Zour	Planned	KPC		Onshore	11.7	720
LEBANON							
Beddawi FSRU	Tripoli	On hold	Lebanese Government		FSRU	3	
MOROCCO							
Jorf Lasfar	Jorf Lasfar	Planned	ONEE	2023	Onshore	5.3	
UAE							
Excelerate FSRU	Ruwais	Operating	GASCO	2016	FSRU	3.8	138
Excelerate Explorer	Dubai Jubel Ali	Operating	DUSUP	2015	FSRU	7.7	150
Fujairah LNG	Fujairah	Cancelled	Emirates LNG	2018	Onshore	9	
Hamriyah Port	Sharjah	Planned	SNOC/Uniper	2019	FSRU	7.5	180

Source: Cedigaz LNG Service, Author.

The MENA region is an area of growing demand for gas linked to rising electricity demand and the growing use of gas in the petrochemical industry. The IEA's New Policy Scenario projects that the Middle East will consume an additional 180 bcm in the period 2016-30, equivalent to a fifth of global gas growth.[66] By 2030, Middle Eastern gas demand reaches around 660 bcm (477 bcm in 2016). In the Gulf Cooperation Council (GCC) region, hydrocarbons producers, hit by low oil prices, further develop their downstream sector to go up the value chain and diversify their economy. The nations have announced billions of dollars in new natural gas

66. IEA, *World Energy Outlook 2017*, November 2017, www.iea.org (New Policy Scenario).

processing capacity. Moreover, the scope for displacing more costly oil products in the power sector to make them available for export makes a strong case for higher gas use.

Despite rising demand for natural gas, the outlook for LNG demand in the region is constrained by demand and supply factors. On the demand side, future gas demand may be lower than expected. This is illustrated by the Sustainable Development Scenario (SDS) of the IEA. Under this scenario, gas demand in the Middle East increases by 100 bcm in the period 2016-30, i.e. half the growth projected in the New Policies Scenario (NPS). In both scenarios, the use of gas in the industrial sector will expand significantly. But the use of gas by the power sector is contrasted among the scenarios. In the SDS scenario, the growth in gas generation is more limited than in the NPS scenario. Gas generation still increases significantly (by a third over the period 2016-30), but renewables increase at a much faster rate and ensure 17% of total electricity supply in 2030 (only 7% in the NPS). Current national policies in the Middle East make this scenario highly probable. In all countries, low oil prices since 2014 have forced governments to reduce energy subsidies and to make energy efficiency efforts. In general, the development of renewable energy sources is prioritized in the MENA region. Morocco is leading regional efforts to develop renewables. It has set targets to increase the share of electricity generating capacity from renewables to 42% by 2020, and 52% by 2030 as well as targets for reducing energy consumption by 12% by 2020 and 15% by 2030 through energy efficiency.[67] The UAE is also pushing to diversify its electricity mix, currently almost entirely dependent on gas, through significant investment in low-carbon power source. The rising contribution of renewables and other sources in the power sector (e.g. nuclear and coal in the UAE) will limit the rise of gas demand in the sector and free up gas supplies, which can be used to expand the industrial and petrochemicals sectors.

On the supply side, in many countries, efforts are made to monetize gas reserves. Production increasingly has to shift to non-associated gas fields, which sometimes are high in sulfur and thus more complicated and expensive to produce. Their project economics rely on gas rather than oil prices. Despite the difficulty to raise domestic gas prices and develop non-associated gas reserves, investment is made to add new sources of production and reduce dependency on imports. Kuwait has started non-associated gas production from its North Jurassic sour gas fields and expects to boost its non-associated gas production to 1 bcfd (10 bcm) by 2023. Abu Dhabi has announced a $109 billion investment over the next

67. IEA, *Morocco 2014 - Energy Policies Beyond IEA Countries*, 2014, www.iea.org.

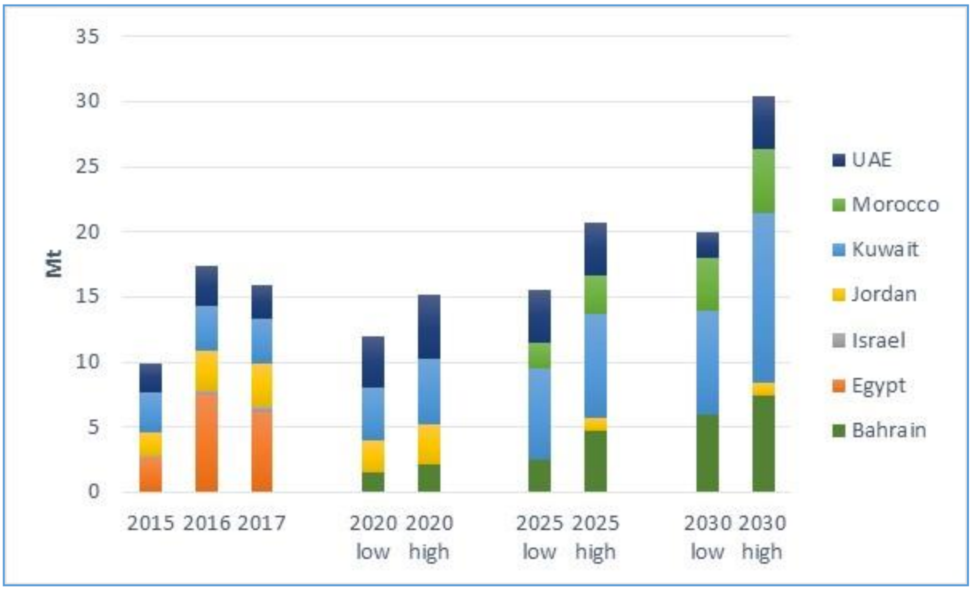
five years to increase its crude oil capacity, expand its petrochemical production and raise its sour gas production to meet its increasing gas demand. These efforts will certainly take time to make a real change in gas production, but they are likely to modify the supply balance in these countries.

Finally, gas flows are changing in the region. The renaissance of Egyptian gas industry will support the strategy of the country to become a gas hub in the region and is likely to revive cross-border gas trade with its neighbouring countries, notably Jordan. The huge gas reserves of Israel are also expected to become part of the changing scene. The recent agreements signed between Egypt's Dolphinus Holdings Ltd and international producers in Israel,[68] but also between Egypt and Jordan,[69] Kuwait and Iraq,[70] may pave the way to more integration of gas trade within the region. On the contrary, geopolitical tensions in the Gulf may restrict pipeline trade flows within the GCC region. Geopolitical issues make difficult to project how cross-border gas trade by pipeline could evolve, but the new gas discoveries in the region have the potential to increase cross-border gas flows within the region, thus reducing the need for LNG imports.

Despite these large uncertainties, the current most probable scenario is a drop of MENA LNG imports in the short term due to the exit of Egypt from the LNG import market and a renewed growth after 2020 as new countries start importing LNG. LNG imports could decline to some 12 Mt by 2020 and rise again to some 20-30 Mt by 2030 due to increased demand by Bahrain, Kuwait and Morocco. This does not include any imports by Saudi Arabia, which could be very significant, but at this stage are very speculative.

68. Energy Egypt, "Dolphinus Holding to Buy Tamar, Leviathan Gas in $15 Billion Deal", 20 February 2018, https://energyegypt.net.
69. Globes, "Egypt Pledges to Supply Gas to Jordan", 6 April 2017, www.globes.co.il.
70. *Iraq Oil & Gas News*, "Kuwait Gas-Supply Pact — Iraq 'Has Much to Gain'", 9 January 2018, www.iraq-businessnews.com.

Figure 16: Outlook for LNG imports in the MENA region



Source: Author based on OIES, Platts.

Annex 4 – Sub-Saharan Africa: a challenging region for LNG-to-power projects

Gas consumption and infrastructure development in Sub-Saharan Africa is still very limited, outside the major LNG producing and exporting countries (Nigeria, Equatorial Guinea, Angola). The region exported 27 Mt of LNG in 2017 as Angola resumed production. The region is expected to increase its LNG exports as new countries are adding liquefaction capacities, such as Mozambique, where FID has been taken to develop one of the LNG projects of the country (Coral FLNG). The floating LNG (FLNG) technology is opening new offshore gas basins for LNG development in the region. An FLNG vessel provides the first liquefaction plant in Cameroon, which started LNG exports in March 2018, and will be used in Mozambique's Coral FLNG project and in the joint LNG export projects developed by Mauritania and Senegal and by Ethiopia and Djibouti. The technology is also expected to lead an expansion of capacity in Equatorial Guinea. This new dynamic is changing the need for regional LNG imports and has already resulted in the cancellation of LNG import projects.

Gas demand in Sub-Saharan Africa was only 33 bcm in 2016 and is concentrated in Nigeria and South Africa. Most other countries have a very small gas market (0.5 bcm to 2 bcm/y) or no gas market at all. The region does not import LNG so far. Four countries are considering LNG imports: Côte d'Ivoire, Ghana, Namibia, and South Africa. In addition, there have been plans to import LNG in Kenya (cancelled in 2016), Mauritania and Senegal (before the countries made offshore gas discoveries), as well as in Mozambique (pending development of its own resources, but the project has not materialized), and in Benin and Sudan (with no concrete plans so far).[71]

All LNG import projects are driven by the need to rapidly increase power generation to resolve power shortages and reach full electricity access. In Sub-Saharan Africa, still 600 million people have no access to

71. Kapsarc, *LNG for Africa*, November 2016, www.kapsarc.org.

electricity, according to the IEA.[72] Insufficient generation capacity is acting as a barrier to further economic growth and social development. Demand for electricity in Sub-Saharan Africa is expected to more than triple by 2040, from a low base of 460 TWh in 2016. LNG import projects are also driven by the absence of significant gas resources, lack of investment to develop small reserves, or temporary gas supply shortages pending the development of new gas discoveries. Some aspiring importing countries in the region intend to substitute imported oil by LNG in power generation.

All projects are LNG-to-power projects, using power plants as anchor customers. Many multilateral financial institutions in that region tend to favour renewables against gas, but gas can provide a source of baseload power in growing urban areas, as a complement to intermittent renewable generation and as a fuel source for the industrial sector. All countries have opted for the FSRU technology and most projects are developed according to the same model, an LNG-to-power project, using an FSRU, allowing to quickly meet rising electricity demand and ease power shortages, or cover temporary gas supply shortages. Many countries lack pipeline networks to distribute gas, so LNG-to-power may solve this difficulty. Initial projects were led by small independent companies, but most of them failed and recent projects are led by major energy groups (Total in Côte d'Ivoire, Gazprom in one of the projects in Ghana).

Currently, there is no project under construction in the region, although Total is expected to take FID in 2018 for its project in Côte d'Ivoire (an FSRU of 3 Mtpa in Vridi, Abidjan area, expected to start in 2018). In Ghana, despite several competing projects to build an import project at Tema, recent developments cast doubt about the materialization of any LNG project. Namibia has not progressed with its LNG-to-power project at Walvis Bay. Power needs are now expected to be supplied by the domestic Kudu gas field. South Africa plans two LNG-to-power projects, one in Richard Bay associated with a power plant of 2,000 MW and the second one in the Coega industrial development zone with a power plant of 1,000 MW. However, no progress has been made since 2016 due to delays in government policy. The projects now seem unlikely to start in 2019 as originally envisaged, but in the best case by the middle of the 2020s, provided South Africa finally pursues the gas option.

72. www.iea.org.

Table 7: Main proposed LNG import terminals in Sub-Saharan Africa

Country/Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
COTE D'IVOIRE							
Ivory Coast LNG	Vridi	Planned (FID in 2018)	CI-GNL (Ivory Coast LNG)	Expected to start in 2018	FSRU	3	
GHANA							
Tema (Golar Tundra)	Port of Tema	On hold	WAGL	was expected to start in 2017	FSRU	5.1	170
Tema LNG (Hoegh Giant)	Port of Tema	Delayed	GNPC / Quantum Power	was expected to start in 2018	FSRU	3.4	170
Gazprom LNG project	Port of Tema	Planned	Gazprom	is expected to start in 2019	FRU/FSU	1.7	
Ghana 1000 (Excelerate FSRU)	Takoradi	Cancelled	Endeavor/GE		FSRU		
NAMIBIA							
Namibia FSRU	Walvis Bay	on hold	Xaris / Excelerate Energy	was expected to start in 2017	FSRU	4.8	138
SOUTH AFRICA							
Coega FSRU (IPP 1000 MW)	Coega	Planned	tbd	was expected to start in 2019	FSRU		
Richards Bay FSRU (IPP 2000 MW)	Richards Bay	Planned	tbd	was expected to start in 2019	FSRU		

Source: Cedigaz LNG Service, Author.

A recent report by the OIES suggests that the Ghana's failure to develop an LNG project in 2016, when LNG prices were low and an FSRU was available at the port of Tema, shows how difficult it could be for LNG import projects in the Sub-Saharan African region to materialize.[73] Namibia and South Africa provide other illustrations of the difficulties to develop LNG-to-power projects in that region. Their projects have long been planned but don't seem close to take off.

A lot remains to be done in Africa's power sector to ensure LNG-to-power projects are viable and to create an environment that is conducive to investments.[74] The key issue is how to attract investors and reduce the risks, given the initial small size of markets, the countries' low credit ratings, low domestic energy prices and higher project risks. An important consideration for these countries is the cost of generating electricity. LNG provides an opportunity to reduce dependency on oil products. But gas has to remain affordable beyond 2020 for those countries looking at LNG imports as a long-term solution. Competition from renewables is growing, especially since the cost of renewable power has fallen.

Although LNG would create an opportunity for Africa to provide power supply to the millions who have not access to it, there is a lot of uncertainty regarding the development of LNG demand in Sub-Saharan Africa. This report has estimated future LNG demand at 1-2 Mt in 2020, growing to 6-10 Mt in 2030.

73. OIES, "Future Prospects for LNG Demand in Ghana", January 2018, www.oxfordenergy.org.
74. Kapsarc, LNG for Africa, November 2016, www.kapsarc.org.

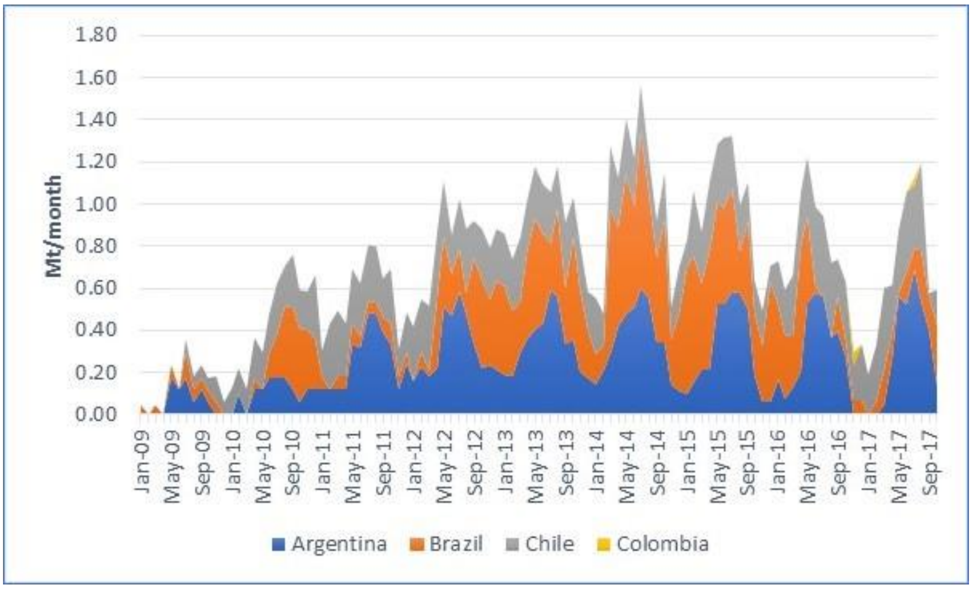
Annex 5 – South America: LNG in competition with unconventional gas and renewables

South America is well endowed with natural gas resources (7.7 tcm of gas reserves as of January 2017, according to Cedigaz). In addition, large resources have been identified in deep-water and unconventional basins. However, lack of investments in E&P has prevented the development of domestic reserves. Marketed gas production has stagnated at around 165 bcm/y over the past five years. Regional gas trade by pipeline boomed in the 1990s and numerous cross-border pipelines were built to integrate the region, notably from Argentina, which exported 8 bcm by pipeline in 2004, mostly to Chile. But reduced production in Argentina led to the '2004 gas crisis'. Argentina was hit by severe gas shortages and eventually interrupted its gas exports to neighbouring countries. This seriously harmed Chile, but also Brazil and Uruguay and opened the door to LNG imports. Argentina was the first country starting LNG imports in 2008, followed by Chile and Brazil in 2009. Since the end of 2016, Colombia has joined the regional LNG importers. LNG imports in the region are driven by security of supply issues. They were initiated to alleviate gas production shortages (Argentina and Colombia), to secure gas supplies after the reduction of gas imports by pipeline (Brazil and Chile). They also provide the necessary back-up of the power system in a region which is highly dependent on hydropower generation (in particular, in Brazil). Significant amounts of natural gas are still traded via pipeline in the region from Bolivia to Brazil and to Argentina (18 bcm in 2016). In addition, two countries in the region – Trinidad & Tobago and Peru – are LNG exporters (13.9 Mt exported in 2017).

South American natural gas demand has grown from 139 bcm in 2010 to 166 bcm in 2016. Argentina and Brazil are the largest consumers, accounting for half of regional gas demand. Gas demand in the region is highly variable. The region's power sector is primarily dependent on hydropower which provides 50% to 60% of total electricity generation. A series of drought and El-Nino events reduced hydropower production in

2014 and 2015 and led to power shortages in several countries. LNG and diesel imports were called to the rescue. In 2014 and 2015, Brazil increased its LNG imports significantly because of severe drought conditions that reduced hydroelectric power availability. The situation has started to normalize, and LNG imports have decreased. From a peak of 12.1 Mt in 2015, South American LNG imports dropped to 8.3 Mt in 2017. The decline was also due to rising gas production in Brazil. LNG imports are also highly seasonal as they mainly cover peak winter demand. In the largest market in the region, Argentina, gas needs have a pronounced seasonality due to the high share of gas demand for heating purposes. The seasonality of South American natural gas demand does not follow international demand patterns due to its position in the Southern Hemisphere (winter months from June to August).

Figure 17: Seasonality of LNG imports in South America



Source: Cedigaz LNG Service.

Brazil and Argentina, which together account for 60% to 80% of South American LNG market, buy cargoes on a short-term basis through spot markets rather than through traditional long-term contracts. This approach affords greater flexibility in accessing imports and financing, but it has also led these countries to pay among the highest LNG prices in the world.

The region had seven LNG receiving terminals at the beginning of 2018 with a capacity of 25 Mtpa, of which five FSRUs.[75] FSRUs have facilitated the import of LNG in South America and all receiving terminals, but in Chile, use FSRUs. Chile also started receiving LNG via an FSRU pending the construction of one of its land-based terminals.[76] Two LNG-to-power projects are under construction in Brazil (Sergipe and Açu 1). Uruguay had plans to install a large FSRU in 2017, but the project has been delayed, and now seems unlikely to materialize.[77] In addition, there are seven terminals at different stages of planning as well as expansions of existing terminals. If all projects were built, which seems unlikely, the region would have an import capacity of about 48 Mtpa at the beginning of the 2020s.[78]

75. In June 2017, Brazil has ended its time charter contract with Excelerate at its Guanabara LNG terminal, but the Guanabara Bay infrastructure has not been decommissioned. So, it is counted as one terminal, but without import capacity.

76. DataFusion Associates, FSRU's – The Great Game Changer, January 2017, www.energyinst.org.

77. Platts, "Uruguay Bets on Renewables, Oil for Power as LNG Project Lags", 15 March 2018, www.platts.com.

78. The terminal planned in Uruguay has not been taken into account.

Table 8: Operating and major proposed LNG import terminals in South America

Country/Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
ARGENTINA							
Bahia Blanca GasPort - Excelerate Exemplar	Bahia Blanca, Buenos Aires	Operating	Excelerate Energy/YPF	2008	FSRU	4.7	151
GNL Escobar - Excelerate Expedient	Parana River, Buenos Aires	Operating	GNL Escobar	2011	FSRU	4.7	151
Puerto Rosales	Puerto Rosales	Planned (FID expected in 2018)	Enarsa	was expected at the end of 2018	FSRU	5.6-8.4	
BRAZIL (a)							
Pecem LNG Golar Spirit	Northeast	Operating	Petrobras	2009	FSRU	1.9	129
Guanabara LNG (b)	Southeast	FSRU removed	Petrobras	2014	FSRU		
Bahia LNG (TRBA Salvador) Golar Winter	Bahia state	Operating	Petrobras	2014	FSRU	3.8	138
Porto de Sergipe I, Golar Nanook	Porto de Sergipe, Sergipe	Under contruction	CELSE (Golar Power, Eletricidade do Brasil)	2020	FSRU	3.8	170
Rio Grande FSRU		Uncertain (license revoked)	Bolognesi Participacoes. Was expected to be sold to NFE	was expected to start in 2019	FSRU	3.8	173
Suape FSRU		Cancelled (replaced by Açu 1)	Bolognesi Participacoes	was expected to start in 2019	FSRU	3.8	173
Açu 1 FSRU (1,238-MW Novo Tempo CCGT)	Açu port and gas hub, Rio de Janeiro	Under contruction	Prumo Logística/BP/Siemens	2020	FSRU	3.8	
Açu 3 (1,672 MW CCGT)	Açu port and gas hub, Rio de Janeiro	Planned		2023	to be defined		
CHILE							
GNL Quintero	Quintero, Valparaiso	Operating	GNL Quintero	2009	Onshore	2.5	334
GNL Quintero	Quintero, Valparaiso (expansion)	Operating	GNL Quintero	2015	Onshore	1.25	
GNL Quintero	Quintero, Valparaiso (expansion)	Planned	GNL Quintero		Onshore	1.25	160
GNL Mejillones	Mejillones, Antofagasta	Operating	GNLM	2010	Onshore	1.5	175
GNL Mejillones	Mejillones, Antofagasta (expansion)	Operating	GNLM	2014	Onshore	0.8	
GNL Mejillones	Mejillones, Antofagasta (expansion)	Planned	GNLM		Onshore		
GNL Penco-Liquen (Hoegh LNG FSRU)	Conception Bay, Biobio	Planned	Biobiogenera	2021	FSRU	3	170
Talcahuano (regional project)	GNL Talcahuano	Planned	EOS	2019	FSRU	1.1	
COLOMBIA							
SPEC FSRU - Hoegh Grace	Cartagena, Carribean Sea	Operating	Sociedad Portuaria El Cayao (SPEC)	2016	FSRU	3.8	170
Colombia Pacific Coast	Port of Bonaventura, Pacific Coast	Speculative	Empresa de Energia de Bogota	2021		4	
URUGUAY							
GNL del Plata - MOL FSRU	Montevideo	On stanby	Gas Sayago	2021	FSRU	3.7	263

(a) Major projects

(b) In June 2017, the Guanabara Bay FRSU was closed. The Guanabara Bay infrastructure has not been decommissioned.

Source: Cedigaz LNG Service, Author.

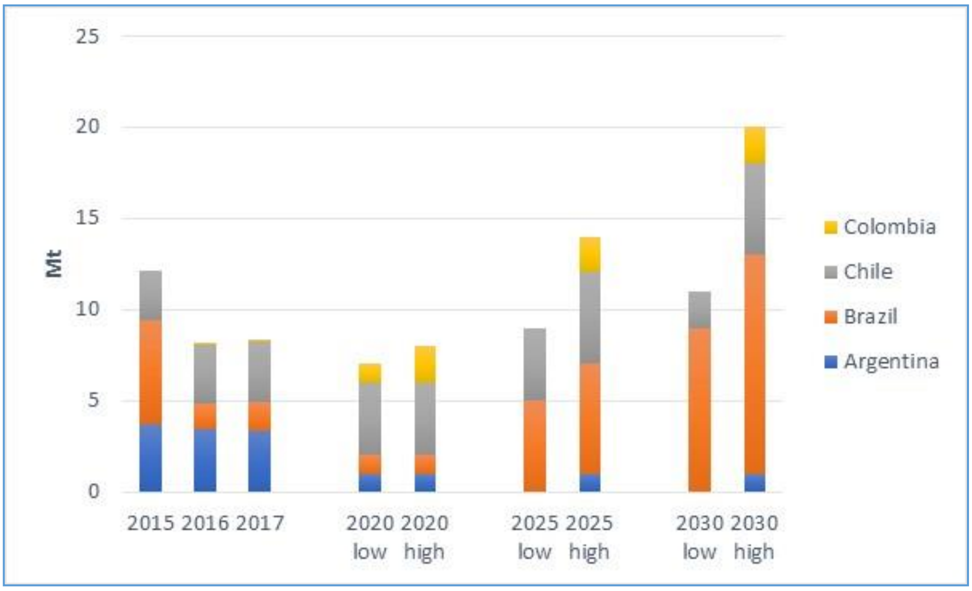
Gas is set to further consolidate its position in South American energy mix, driven by its growing importance in the region's power sector.[79] The IEA projects Central and South American gas demand to rise from 166 bcm in 2016 to 271 bcm by 2040, at an average annual growth of 2.1% over the period 2016-40.[80] Many governments in the region see natural gas as a low-carbon energy option that can support their increasing turn towards renewables. Nevertheless, growth prospects for LNG demand are uncertain as countries such as Argentina and Brazil work towards becoming self-sufficient in gas supply and could even become regional exporters. The two countries accounted for 60% of the region's LNG imports in 2017. Production in Brazil is rising thanks to increased associated gas production from the pre-salt oilfields. In Argentina, there are ambitious plans to increase production from shale gas, mostly from the Vaca Muerta play, in the Neuquén Basin. Brazil is the most advanced, while shale gas in Argentina has still to demonstrate its potential. However, despite high growth in gas production, Brazilian LNG imports are expected to increase again after 2020 driven by LNG-to-power projects built by private entities and secured by long-term PPAs. The opening of the Brazilian gas market is creating new opportunities to grow the market and secure electricity supplies. In Argentina, future LNG imports are highly dependent on the growth of its domestic gas production, but also on gas imports by pipeline from Bolivia. The government intends to stop LNG imports altogether or at least reduce them to the peak winter period only. The country relies on an increase in seasonal deliveries from Bolivia to reach this goal. But Bolivia needs to invest in new field development to maintain its production and exports. If the country is not able to maintain its export levels, a rise in regional LNG imports will be required in the short term. The expected growth in Colombian LNG imports could be jeopardized by deep-water gas production off Colombia's Caribbean coast, expected to start in the 2020s. Chile LNG imports are expected to continue growing, reinforced by the decision to phase-out coal. However, the growth depends on future gas development in Argentina which could regain its gas exporter status and export gas to Chile through the numerous cross-border pipelines built in the 1990s. Rising renewable power, which is expected to provide 60% of Chilean electricity by 2035, may also limit the growth in LNG demand. Uruguay was expected to join the rank of LNG importers in 2017, but its LNG import project has been delayed and now seems in standby.

79. OIES, "South American Gas Markets and the Role of LNG", October 2016, www.oxfordenergy.org.

80. IEA, *World Energy Outlook 2017*, November 2017, www.iea.org.

The extreme dependence of South American gas and LNG demand on hydropower makes future LNG imports quite unpredictable. While investments in renewable power sources will ease the region's hydropower dependence, natural gas-fired generation will remain vital due to the intermittent nature of solar and wind energy. The difficulty to forecast South American LNG demand is illustrated by the OIES forecasts.[81] The OIES projects that South American LNG demand will decrease from 15.8 bcm in 2015 to 6.9 bcm in 2020 under normal weather conditions but could rise to 20.6 bcm in case of a very dry year in Brazil. Based on an analysis by country, this report sees growth prospects in Brazil after 2020 (despite its growing production) and Chile, but in the latter case dependent on how cross-border gas trade evolves in the region. South America's growing gas production will redraw cross-border gas flows within the region and may dampen the region's appetite for LNG. LNG demand could remain flat until 2020 (7 Mt to 8 Mt in 2020) and increase again in the 2020s to 11-20 Mt by 2030, provided LNG remains competitive.

Figure 18: Outlook for LNG demand in South America



Source: Author based on OIES, Platts.

81. OIES, "LNG Markets in Transition: The Great Reconfiguration", Oxford University Press, 2016. Based on the low case scenario.

Annex 6 – The Caribbean and Central America: an ideal region for small-scale LNG projects

The Caribbean and Central American region is described as a potentially ideal region for LNG imports due to its current heavy dependence on diesel and fuel oil for power generation, high electricity tariffs and its proximity to regional LNG suppliers in Trinidad & Tobago and on the US Gulf Coast.[82] The ability to switch from liquid fuels to LNG is being pursued as a way to lower costs and bring environmental benefits. The current LNG market is small – in 2017, the three regional LNG importers (Dominican Republic, Jamaica and Puerto Rico) imported 2 Mt – but it has scope to grow further as more and more countries develop LNG projects. The use of LNG for bunkering adds further growth prospects. Due to the specific geography of the region, small-scale FSRUs are well suited to feed LNG to new markets. Another cost-efficient delivery option is through a local hub either using ISO containers or break-bulk projects, which are designed to partially unload at multiple ports during a single voyage.

The Caribbean and Central American region had three LNG terminals in operation at the beginning of 2018. Their import capacity totals 5.1 Mtpa. In addition, there are expansion projects in Puerto Rico and Jamaica, and Panama is slated to start LNG imports in 2019. Other Caribbean and Central American countries that could enter the LNG market include Barbados (which has signed a contract with AES for LNG supply via ISO-containers), Bermuda, the Bahamas, Cuba and Haiti (which is building a small-scale 0.4 Mtpa LNG terminal). On the Pacific coast of Central America, El Salvador has plans to develop an LNG terminal, using an FSRU.

82. OIES, "The Potential Market for LNG in the Caribbean and Central America", November 2017, www.oxfordenergy.org.

Table 9: Operating and major proposed LNG import terminals in the Caribbean and Central America

Project	Location	Status	Sponsors	Start-up date	Type	Capacity (Mtpa)	Storage ('000 cm)
DOMINICAN REPUBLIC							
AES Andres LNG	Punta Caucedo, San Domingo	Operating	AES Corp.	2003	Onshore	1.9	160
EL SALVADOR							
Energia del Pacífico LNG project	Port of Acajutla	Planned	EDP	2021	FSRU	0.5	
JAMAICA							
New Fortress LNG - Golar Artic	Bogue, Saint James	Operating	New Fortress Energy	2016	FSU	0.26	
New Fortress LNG (expansion)	Jamalco	Under Construction	New Fortress Energy	2020	FSU	0.13	
New Fortress LNG - (expansion)	Old Harbour Bay	Under Construction	New Fortress Energy	2019	FSU	0.2	
PANAMA							
Costa Norte LNG	Telfers Island, Colon	Under Construction	Gas Natural Atlantico	2019	Onshore	1.5	
Martano LNG-to-power project	Isla Margarita, Colon	Planned	Martano, Inc.	2020	Onshore		
PUERTO RICO							
EcoElectrica	Penuelas	Operating	EcoElectrica	2000	Onshore	2.9	160
Aguirre Offshore GasPort	Salinas	Cancelled in 2017	Prepa / Excelerate Energy		FSRU		151

Source: Cedigaz LNG Service, OIES, Author.

According to the OIES, the generation capacity theoretically replaceable with LNG in the region is 14.6 GW, of which 5.1 GW is in Central America and 9.5 GW in the Caribbean Islands.[83] This would require a maximum theoretical gas volume of 24.2 bcm/y, of which 15.7 bcm/y is in the Caribbean and 8.5 bcm/y in Central America. The small size of the markets presents logistic and commercial challenges for the supply of LNG and for financing the projects, and not all the potential will be realized. Renewables are a key competitor of LNG projects in the region. But the region is very active to develop small-scale delivery solutions. Although the Caribbean and Central American LNG markets are very small individually, the substitution of diesel and fuel oil in the power sector and the development of other uses (e.g. LNG bunkering) may increase regional LNG imports from 2 Mt in 2017 to some 4 Mt by 2020 and 8-10 Mt by 2030.

83. OIES, November 2017, *op. cit.*

Annex 7 – Main units and conversion

The gas industry uses different units: in the US, it is typical to speak in billion cubic feet (bcf) and million cubic feet per day (mmcfd). In Europe, it was common to use billion cubic meters (bcm) and it is becoming more usual to use kilowatt-hours (kWh) to report natural gas production and consumption. Some countries (e.g. Pakistan) typically use million cubic meters per day (mmcm/d). In the LNG industry, it is common to speak in million tons of LNG (Mt). To reconcile these various units, the following conversions were used in this report.

	Multiply by					
To From	billion cubic metres (bcm)	billion cubic feet (bcf)	million tonnes oil equivalent (Mtoe)	million tonnes LNG (Mt)	trillion British thermal units (10^6 MBtu)	million barrels oil equivalent (Mboe)
1 billion cubic metres (bcm)	1	35.3	0.90	0.735	35.7	6.16
1 billion cubic feet (bcf)	0.028	1	0.025	0.021	1.01	0.17
1 million tonnes oil equivalent (Mtoe)	1.11	39.2	1	0.82	39.7	6.84
1 million tonnes LNG (Mt)	1.36	48.0	1.22	1	48.6	8.37
1 trillion British thermal units (10^6 MBtu)	0.028	0.99	0.025	0.021	1	0.17
1 million barrels oil equivalent (Mboe)	0.16	5.74	0.15	0.12	5.80	1

Source: BP Statistical Review of World Energy 2017.

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