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# International Trade in Natural Gas: Golden Age of LNG?

Yichen Du* and Sergey Paltsev*†


### Abstract

*The introduction of liquefied natural gas (LNG) as an option for international trade has created a market for natural gas where global prices may eventually be differentiated by the transportation costs between world regions. LNG's trade share in 2013 was only about 30 percent of the total global trade in natural gas, but use of LNG is on the rise with numerous projects in planning or construction stages. Considering LNG projects that are under construction, planned, or proposed, we provide an analysis of LNG prospects for the next decade. LNG has substantial unexploited potential in terms of reducing capital requirements (especially for liquefaction projects), expanding new technology frontiers (e.g. floating LNG), serving new markets, and establishing new pricing schemes that better reflect the fundamentals of supply and demand. Trade volumes are projected to increase from about 240 Mt LNG in 2013 to about 340–360 Mt LNG in 2021. Despite potential challenges from weaker demand in Asia, longer-term projections show that LNG trade is bound to show substantial growth, partially due to geopolitical tensions that might increase LNG flows to Europe. However, these perspectives largely depend on demand choices, the availability and evolution of alternative fuels (e.g. renewable energies), and—most importantly—political decisions framing economic behavior.*


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## 1. INTRODUCTION

Natural gas has a long history as an energy source beginning in the late 1800s when it was used as a fuel for street lighting. Many years later, economic sectors, including power generation, began introducing natural gas as a fuel or feedstock. Today, more than 40% of worldwide natural gas is consumed in the generation of power and heat. Other major uses include residential space heating and industrial fertilizer production (IEA, 2013). The technical and financial challenges of transporting natural gas over long distances has resulted in regionally segmented markets, using pipelines as a key mode of transportation. In the most recent decade, another option for gas trading became significant: liquefied natural gas (LNG). LNG reduces the volume of natural gas by about 600 times, allowing efficient transportation over long distances by ship. In 2013, about one third of global trade in natural gas was conducted using LNG (BP, 2014).

The objective of this analysis is to investigate the prospects for LNG trade in the next 10–20 years. We explore current natural gas trade flows, implications of projects currently under construction on future volumes and prices, and potential development of LNG markets based on announced and speculative plans. LNG projects are capital intensive—a typical LNG export facility costs about $10 billion (as discussed later, this amount varies substantially from project to project). As the LNG infrastructure is built to last for decades, dynamics of global gas markets may affect the performance of a particular project in very substantial ways.

Historically, long-term contracts have underpinned the majority of the natural gas trade. These contracts provide a mechanism to allocate risks among the actors in the supply chain and to guarantee a return on investments in the expensive transportation infrastructure. By the end of the 20th century, long-distance natural gas trade rapidly picked up speed, and in 2013, about one third of global gas production was traded (BP, 2014). A larger share of gas is traded now based on "gas-on-gas" competition, where prices are de-linked from oil indexation. IEA (2013) estimates that about 40% of international gas trade in 2012 was based on gas-on-gas contracts—a substantial increase from 2005 when the corresponding share was about 20%. LNG trade creates the opportunity to establish a global natural gas market, with pricing based on the fundamentals of natural gas supply and demand.

The paper is organized in the following way. In the next section we provide a brief introduction of the history, current development, and value chain of LNG industry. Section 3 provides a more detailed discussion of the structure of LNG industry including liquefaction plants, shipping, and regasification facilities. In Section 4 we present a mid-term outlook for LNG industry. Uncertainties and major factors that may affect the development of LNG markets are provided in Section 5. Section 6 concludes.

## 2. LNG: HISTORY AND CURRENT DEVELOPMENT

The history of liquefied natural gas dates back to 1917, when the first natural gas liquefaction facility began operation in West Virginia as part of a research program to extract and stockpile helium (Foss, 2007). In 1941, the first commercial plant was built for peak-shaving purposes, i.e. liquefied natural gas was stored for future usage. In January 1959, the world's first LNG tanker, the Methane Pioneer, shipped the first cargo of LNG from Lake Charles, Louisiana, to Canvey Island, United Kingdom. Inspired by this successful demonstration, nations started to commit and implement large-scale commercial LNG projects.

In 1964, the British Gas Council begins importing LNG from Algeria, making UK the first LNG importer and Algeria the first exporter. In 1969, the United States exported LNG from Alaska to Japan for the first time. At that point, as shown in **Figure 1**, the LNG business began to take off globally with many destinations in Japan, Europe, South Korea, China and other countries. A large share of global LNG is still destined to Japan. Global LNG volumes are tripled from about 100 billion cubic meters (bcm) in 1997 to more than 300 bcm in 2010 (1 bcm = 35.3 bcf = 0.0353 Tcf = 0.74 Mt; for more unit conversion, see Appendix A). The recent economic recession in Europe led to a decline in LNG volumes in 2012.

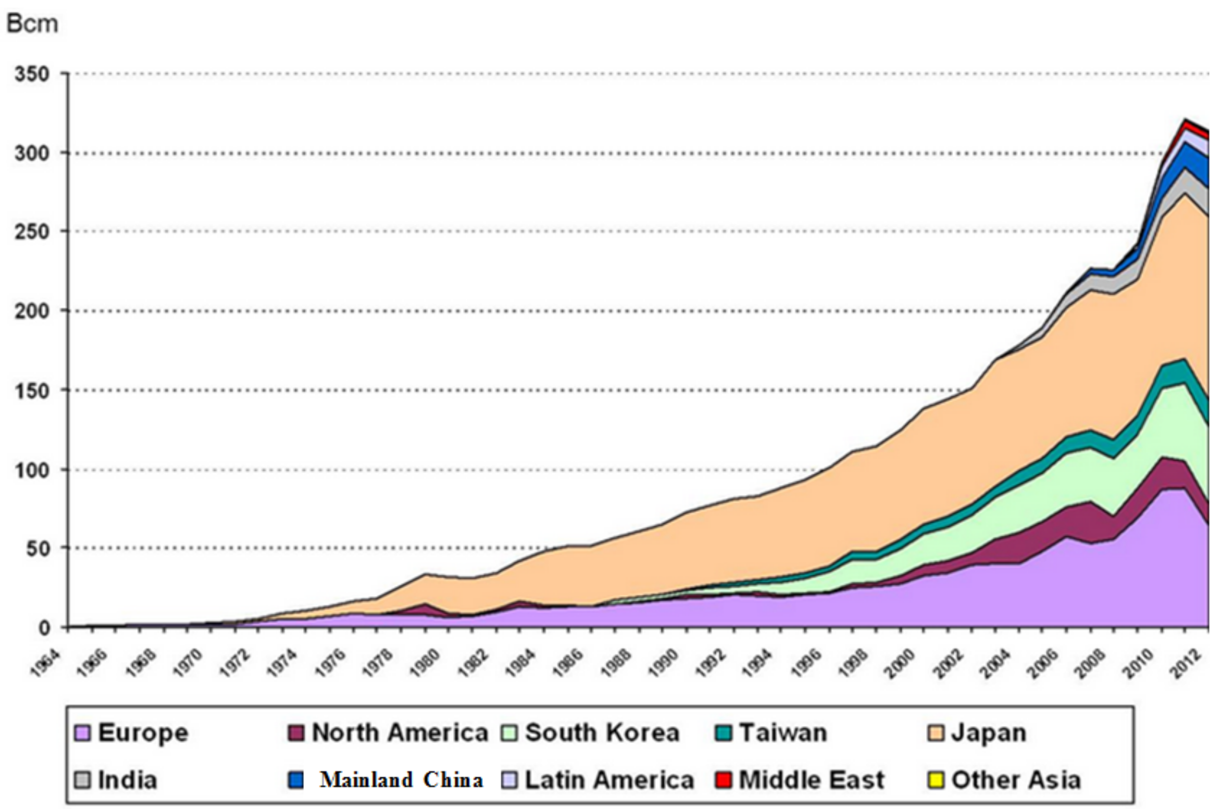


**Figure 1.** Growth in global LNG trade by destination from 1964 to 2012. Source: Cedigaz (2013).

Technological innovations not only make LNG easier and safer to transport, but they also expand the boundary of the business. In 2004, the first offshore re-gasification facility, Port Pelican, started operations in the Gulf of Mexico, which lessened the requirement for land-use. In 2010, BG Group sanctioned its Queensland LNG project, the first in the world to use coal bed methane as the feedstock. One year later, Prelude LNG, a floating liquefaction project planned to be located offshore Australia, was sanctioned by Shell, which may enable the industry to tap stranded resources that were not economically feasible before.

Currently, LNG represents about 30% of the international gas trade volume, and about 10% of total gas consumed annually (BP, 2014). The figure was 237.7 million tonnes (Mt) LNG in 2012, down from 243.1 Mt in 2011, which is the first slide in the past three decades (International Gas Union, 2013). The figure further contracted 5% in the first 8 months of 2013 (Shiryaevskaya, 2013), but the trade picked up in the later part of the year with BP reporting the total 2013 volume as 239 Mt (BP, 2014). Despite the recent slowdown, experts and companies are still optimistic about the long-term growth of this industry (IEA, 2013).

The LNG market value is now between $120~160 billion per year, based on the 2013 trade volume and an average price in the range of $10 to $14 per million British Thermal Unit (mmbtu). By our estimations (see Appendix B), such a massive trade volume is supported by a liquefaction capacity of more than 293 Mt per year distributed in 18 countries, a global shipping fleet with a combined capacity more than 70 Mt, and a regasification capacity of 642 Mt per year in more than 25 countries (as of January 2014).

Another eminent feature of the natural gas market is regional divergence of price. **Figure 2** shows that in 2013 the average price of LNG in Europe was $11/mmbtu, while in Japan it amounted to $16/mmbtu. In comparison, the average Henry Hub price in the US fluctuated in between $2 to $5/mmbtu in recent years, significantly lower than its counterparts in Asian and European markets. Many analysts expect that further LNG development—and especially future gas trade flows from North America to Asia—may narrow the gap between regional prices.

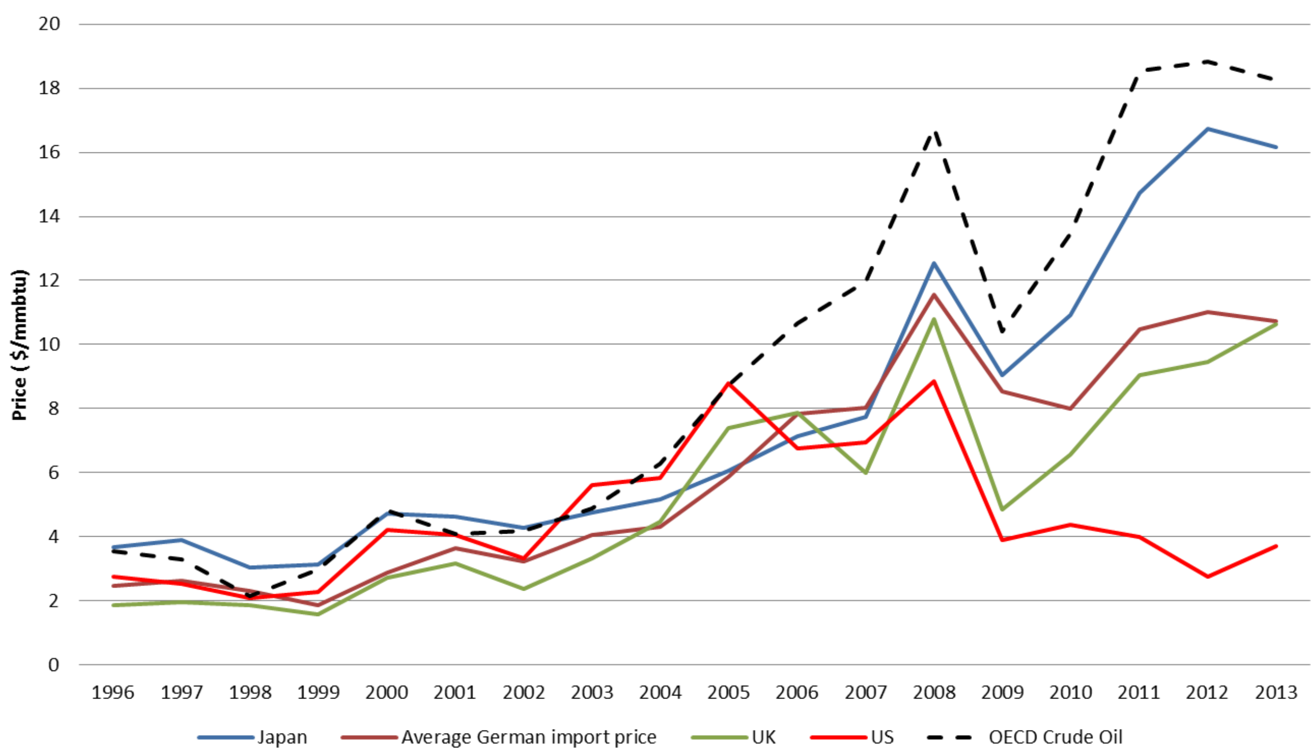


**Figure 2.** Natural gas prices in Japan, North America, and Europe from 1996 to 2013 as compared to crude oil price. Source: BP (2014).

LNG has attracted much attention from market analysts and market participants in the recent years (IEA, 2013). Its fast development is mainly attributed to its flexibility in transportation in terms of destination choices (compared to a pipeline transport). Natural gas has many advantages over other energy sources that have also accelerated its penetration. For example, the combined cycle gas turbine (CCGT) technology makes LNG an especially attractive fuel for electricity generation. A CCGT plant can be built in just 1 to 2 years, with small initial investment compared to a nuclear or coal power plant. It also provides a better flexibility and efficiency. Many analysts see natural gas as a bridge to a low-carbon energy future (MIT, 2011; IEA, 2011; Jacoby et al, 2012), because it can substitute for more carbon-intensive fuels in power generation and provide a flexible generation option as a backup for intermittent renewables. The tragic Fukushima nuclear accident resulted in a drastic decline in nuclear power production and scaled down ambitions for future nuclear expansion in many nations. The regain of confidence may take a long time, if it eventually happens. In Japan, the respectable safety record of operations of LNG industry makes it a good alternative to nuclear energy.

In US and China, natural gas fueled vehicles have the prospects of making substantial contribution to transportation needs (Yip, 2014). US development is driven by relatively low natural gas prices, while in China concerns about air pollution and oil imports are main driving factors.

In terms of trading natural gas, LNG has some merits that pipeline gas does not possess. LNG destinations are flexible, which lowers financial and geopolitical risks, as is often the case for pipeline gas investments, which tend to be complicated by temporal geopolitical tensions (e.g. the Russian pipeline gas supply to Europe must pass through Ukraine).

The value chain of LNG industry (**Figure 3**) includes upstream gas production, liquefaction and storage, shipping and regasification and utilization. Among these, liquefaction is the most critical link. Usually, it takes 4 to 5 years to build a liquefaction plant, not including time spent on initial planning and negotiations. In comparison, an LNG tanker and a regasification plant can be built in less than 2 years. In addition, the liquefaction plants are some of the most capital-intensive projects in the world. For instance, Chevron's cost on the Gorgon LNG plant is more than $54 billion, overshadowing any LNG tankers or regasification plants, which are on the scale of several hundred million dollars. The huge initial investment can bring considerable financial risks given the volatility of energy prices. Liquefaction plants also arouse more political concerns and uncertainties. Countries like Qatar, Trinidad and Tobago, USA, and Indonesia are worried about the impact of export on domestic gas demands. Not surprisingly, liquefaction plants are crucial for the further expansion of the industry, and they are the focus of an analysis of individual projects and the LNG industry (e.g., Deutsche Bank, 2012; Paltsev *et al.*, 2013a).

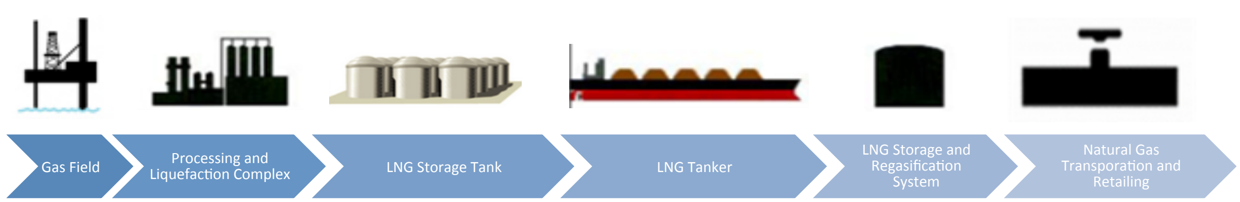


**Figure 3.** LNG value chain.

## 3. THE STRUCTURE OF LNG INDUSTRY

### 3.1 Liquefaction Plants

As discussed above, liquefaction plants are the most important sub-system in the value chain of LNG industry. The tremendous financial commitment, long construction period, complex political considerations and fluctuations of global energy markets all make it a challenging business. To evaluate the costs of LNG projects, one of the most commonly used characteristics is the average initial investment required for a production capacity of one ton per year, which is measured in dollars per ton of annual LNG production ($/tpa). Although it is not a well-defined term, as there is no clear boundary between liquefaction plant and upstream facilities, dollars per ton can provide a rough comparison between the costs of different LNG plants, and thus is widely used in academic and business literatures.

As shown in **Figure 4**, two decades ago, the cost of building an LNG liquefaction plant was on average $350/tpa, which decreased to around $300/tpa in the 2000s (Apache, 2012). However, the costs have risen steeply to more than $1,000/tpa since 2010. To understand these substantial changes, a scrutiny on the components and the structure of the costs is required.

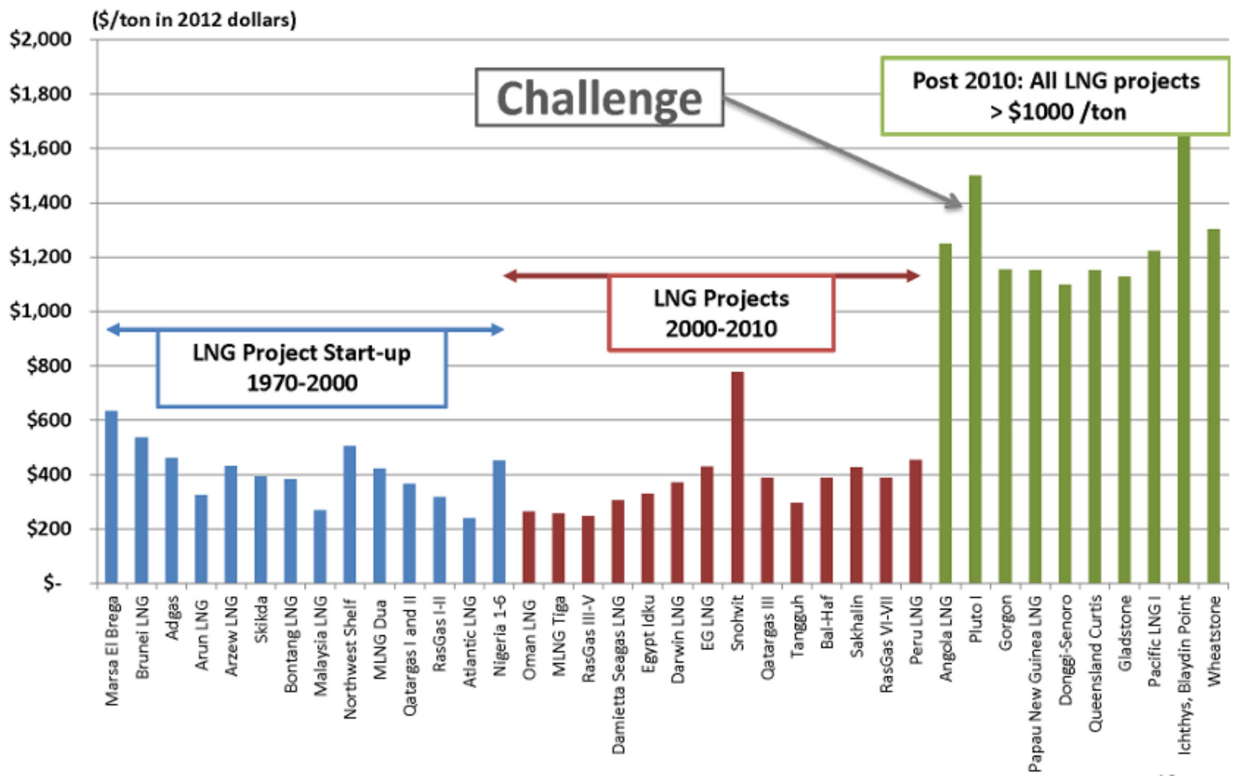


**Figure 4.** CAPEX of LNG capacity. Source: Apache (2012).

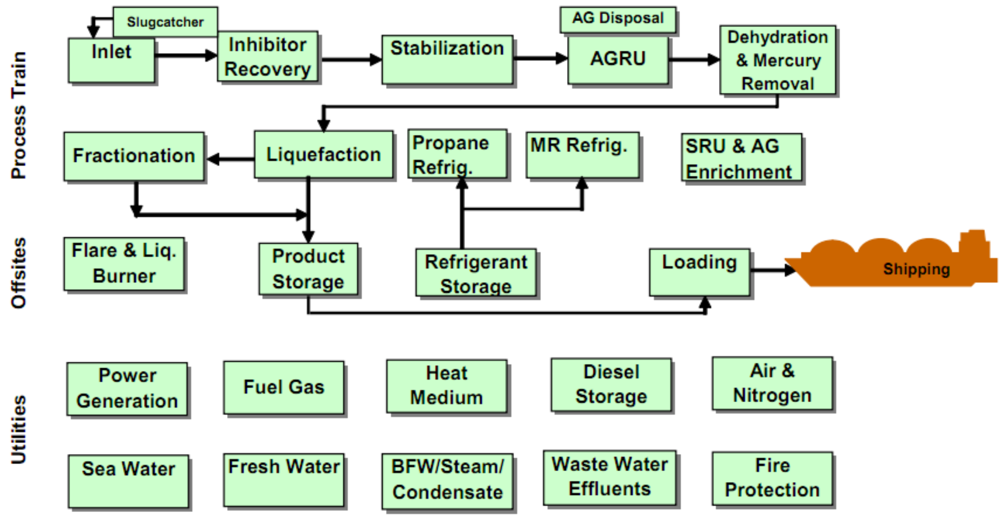


**Figure 5.** Components of LNG liquefaction plant. Source: KBR (2007).

The construction of a liquefaction plant involves some or all of the following major elements: feed gas reception and treatment, liquefaction, refrigerant, fractionation, storage, marine and loading and utility sections. A detailed breakdown can be seen in **Figure 5**. Depending on the feed gas composition, the local conditions, and requirement on the final product, some of these components may be dispensed. For instance, if available, the plant can be connected to the electric grid, saving the initial investment on its own utility section, which can amount to 20% of the total cost.

Another way to decompose the cost is to look at different factors that influence the total expenditures, such as:

- *Materials*, which represents the costs related to equipment and auxiliary materials;
- *Labor*, or "subcontract" cost, which covers the work hour cost at the plant location;
- *Management and engineering* costs, mainly comprised of owners' personnel expense during project development, including legal, permitting, management and planning, etc.;
- *Financing*, depending on the structure of the source of finance (equity and debt costs);
- *Location-specific characteristics*, such as temperature, marine situation and local residence. For instance, an increase of 5˚C in ambient air temperature (a location-specific factor) can raise the total cost by more than 4% due to a lower productivity (Kotzot, 2007); however, building LNG in the harsh Arctic conditions substantially adds to the costs (see an outlier for a cost in 2000–2010 for Norwegian Snohvit LNG plant on Figure 4).

Many researchers point out that the worldwide rapid increase of cost results from low availability of engineering-procurement-construction (EPC) contractors and skilled workforce in the industry, as well as high raw material prices (Hiroshi, 2011; Ellis and Heyning, 2013).

However, there are also region-specific reasons for the increase. For instance, from January 2009 to January 2012, the Australian dollar strengthened by more than 65%, adding to the budget overrun in projects under construction in Australia.

### 3.2 Commercial Risks and the Influence on Financing

Many commercial issues along the entire LNG chain can affect the financial cost and feasibility of a project, as the associated risks have strong influences on the financial structure and the required return of investors. The equity ratio[1] of a project can vary significantly. Given the immense cost of a LNG liquefaction plant and the potential impact on the balance sheet, even the largest oil and gas companies may need to seek outside financing. Moreover, the interest rate for debt is generally much lower than equity, which incentivizes project sponsors to have higher financial leverage. However, the ability to raise debt is limited by the underlying risks of the project. Low-risk LNG projects can have equity portion and weighed average capital cost as low as 10% and 8% respectively, while high-risk projects can require more than 50% and 15% (Kotzot, 2007). There are many detailed analyses on infrastructure investment risks (Henisz, 1999; Grimsey, 2002), our approach here is to group risks relevant to LNG projects into four categories: upstream, project-level, downstream and sovereign risks.

When evaluating upstream risks, stakeholders focus on the size and quality of the gas reservoir as well as the growth of domestic needs of natural gas. To justify the construction of a traditional onshore LNG plant, very substantial (at least 3–4 Tcf) gas resources have to be discovered and certified. However, the geological formation of the carbohydrate reservoir is very complex, which can influence the volume of the actual extractable resource and its production cost. A favorable formation of the reservoir (and thus a lower feed gas price) can increase the margin of the project. A gas field with more condensates is also considered more profitable than a field with only dry gas, *ceteris paribus*, given the higher value of liquid fuels. But if the domestic demand for natural gas is expected to grow rapidly in the future, investors may be concerned about the availability of feed gas for export purposes.

The project-level risk is internal to the construction and operation of a liquefaction plant, which can be influenced by the credit rating of sponsors, the track record of the participating companies, the overall cost competitiveness and whether the technologies are proven. In principle, the higher the credit rating is, the easier it is for sponsors to raise cheaper funding. Sometimes, to improve the overall credit rating, sponsors will choose to secure funds through an incorporated joint venture rather than raising funds individually. The track record of the participating companies is an indication of the capability of the contractors, local partners and sponsor companies, and can have significant impact on investors' confidence, especially when new technologies are adopted or it is a "greenfield" project. One example is the ability to secure site permission through building constructive relationships with local communities and government. A lack of such capability may

[1] Equity ratio measures the proportion of the total assets that are financed by stockholders and not creditors.

result in local oppositions and thus postpone or even terminate the project. Lastly, lower liquefaction cost can provide more buffers for market volatility and mitigate investors' risks, which is extremely important in an increasingly dynamic market.

The downstream risk refers to those related to transporting and selling of LNG cargos. It is largely determined by the market expectation of future demand. Some important factors are the long term sales and purchase agreement (SPA) and its pricing formula (see **Figure 6** for a representative contract price curve and more detailed discussion in Appendix C for SPA impacts on downstream risk), shipping contract and remainder volumes available for a spot market. Having remainder capacity can have both negative and positive aspects. On one hand, it can result in underutilization of the facilities and would potentially increase the breakeven price. On the other hand, it can provide the supplier with opportunities to profit through spot cargos when the market is tight. The risks and costs associated with shipping will be discussed in the next section.

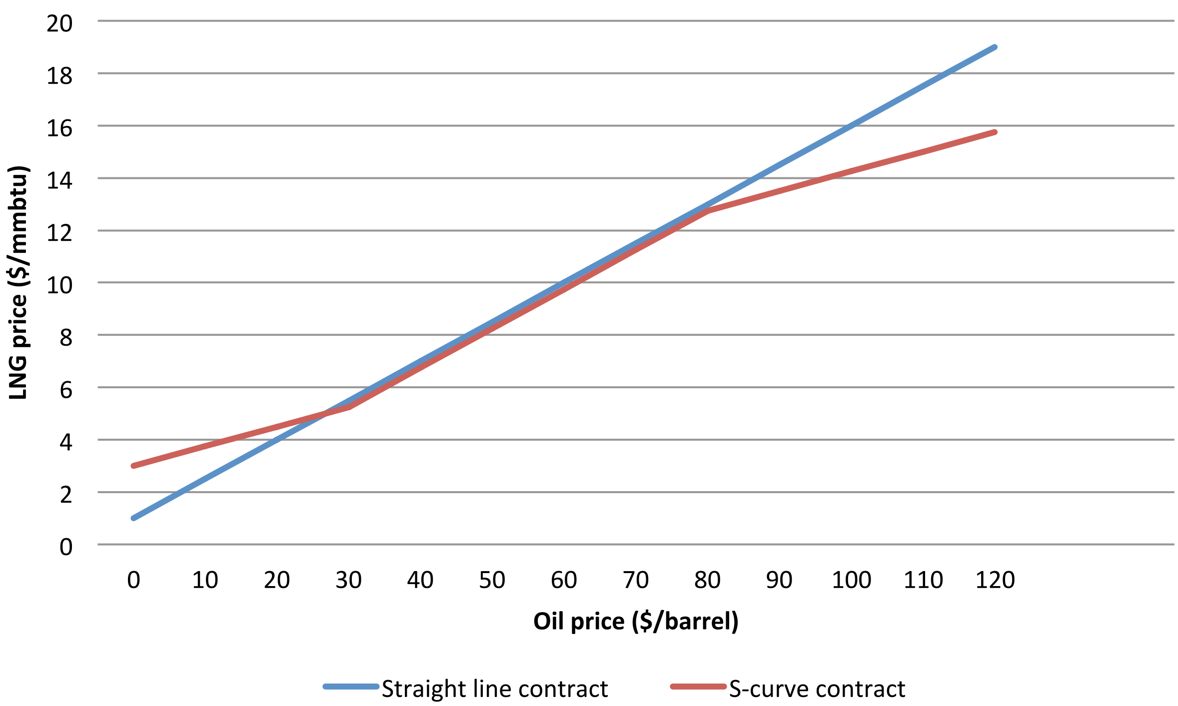


**Figure 6.** Representative LNG contract price mechanisms.

Finally, the sovereign risk embodies the uncertainties related to the host nation. Some common considerations include stability of the reservoir owner, political stability and predictability of tax regime, regulation and royalty, as well as exchange rate fluctuations and import duties.

However, there is no single formula to map all these risks into the corresponding financial cost, as they are not all quantifiable, and some of them are very sensitive to market sentiments. Moreover, given the limited publication of underlying contract information, the exact financial cost is very hard to estimate (see, for example, a discussion about quantifying the inputs to a simplified LNG DCF model in Paltsev *et al.*, 2013a).

### 3.3 Major LNG Players

The entrance barrier of the LNG industry is high, which leads to a high industry concentration. As of early 2014, there are 18 nations in the world that are exporting LNG[2], among which only 3 are OECD countries (Australia, Norway and USA). Out of the built capacity (300 Mt total)[3], more than 60% is concentrated in the top five exporting nations: Qatar, Indonesia, Australia, Malaysia and Nigeria. From the perspective of regional distribution, North Africa and the Middle East count for almost half of all export capacity. However, the market is dominated by some of the largest national and international oil companies. The five largest LNG companies[4] possessed about 45% of the world's total capacity in 2010 (Krijgsman, 2011).

However, liquefaction capacity alone may not be a perfect measure of the market concentration. Another important factor is utilization rate. For instance, Qatar has a capacity of 77.4 Mt, representing about 27% of global LNG capacity in 2012. However, it supplied more than 32.6% of global LNG cargos due to a high utilization rate.

In the past two decades, the global liquefaction nameplate capacity utilization rate vacillated between 75% and 87% (International Gas Union, 2013). Exterior factors such as changes in regulations and policies, political instability, field depletion and accidents could influence the utilization rate of individual plants. For example, in 2012, Egypt, Algeria and Trinidad decreased LNG exports to meet fast-growing domestic energy demand, while Yemen, Libya, Nigeria and Venezuela struggled with geopolitical and financing issues.

### 3.4 Ships

LNG shipping is a niche market composed of around fifty medium- to large-sized companies. Traditionally, the largest shipping companies are those affiliated with National Oil Companies, such as Nakilat (Qatar), MISC (Malaysia), Bonny G.T. (Nigeria) and NGSCO (United Arab Emirates). However, there are many other players who possess or are rapidly building commeasurable shipping capabilities (see **Figure 7**). For instance, Golar LNG, Teekay LNG Partners, Hoegh LNG and GasLog LNG Service, some of the largest listed shipping companies, are expected to build about 30 new cargos in the coming two years (International Gas Union, 2013). Importers (i.e. utility companies and conglomerates) can also choose to own transporting subsidiaries, which can be seen in the cases of Maran Gas Maritime (GDF SUEZ), Hyundai and Mitsui OSK Lines. Furthermore, International Oil companies (such as BP, BG Group and Chevron) and private shippers (such as Dynagas and SK Shipping) also have their own shipping fleets. Last but not least, a number of commodity traders such as EGL Group, Morgan Stanley and J.P. Morgan also provide vessel leasing services. Most carriers owned by NOCs and

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[2] 19 nations have export capability, but currently (as of summer 2014) Libya is not exporting due to political instability.

[3] Including the 3 Mt Libyan plant Marsa El Brega and the Indonesian plant Arun LNG that is expected to stop exporting by the second half of 2014.

[4] Based on the equity holding in global LNG projects, including Qatar Petroleum, Sonatrach, Petronas, Exxonmobil and Royal Dutch Shell.

importers are committed to long term contracts, while ships controlled by independent companies can either operate under long-term charter deal or be rented in the spot market.

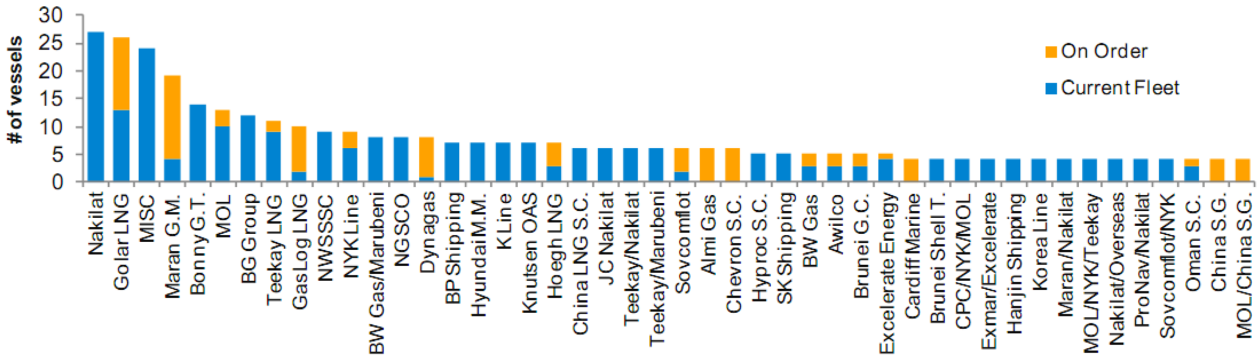



**Figure 7.** Current and ordered LNG Fleet. Source: International Gas Union (2013).

A rule of thumb is that every incremental 1 Mt of liquefied natural gas production per year responds to a demand for 1–2 additional LNG carriers, depending on the size of the carrier. By 2013, there is a global LNG fleet of 362 vessels with a total transportation capacity of 24 Mt (International Gas Union, 2013), which implies an average cargo turnover rate of 11 to 15 times per year, given the 237.7 Mt trade in 2012 and an idle rate between 10% and 30%[5]. Carriers smaller than 18,000 cubic meters (capable of carrying about 8,100 metric tons[6]) are not counted here since they are not suitable for cross-border transportation. Eligible ships can be categorized into conventional and non-conventional ones. The former can be further classified into Moss-type and Membrane-type vessels, depending on different storage tanks utilized. The latter include Q-Series types (currently the largest in the world[7]) and Floating Storage and Regasification Units (FSRU). The average size of LNG carriers has been increasing in recent years due to the introduction of Q-Series types. In 2012, the average capacity was approximately 148,000 cubic meters (capable of carrying about 66,000 ton LNG).

There are relatively few shipyards that possess the technical capability to build LNG carriers. Samsung, Hyundai, and Daewoo are the largest among them. However, new entrants and a downturn in other shipping markets have lowered the cost of new ships, from about $260 million in 2008 to about $200 million in 2012. South Korea still dominates the market, taking 85% of the new building contracts in 2012, while Chinese and Japanese companies take 9% and 7% respectively (BRS, 2013). However, some analysts estimate that Chinese shipyards have reached

[5] Idle rate describes the time that ships are not in service due to lack of contracts or as a result of maintenance.

[6] The density of LNG is roughly in the range 410 to 500 kg/m$^3$, with a median of 450 kg/m$^3$, depending on temperature, pressure, and composition, according to http://www.unitrove.com/engineering/tools/gas/liquefied-natural-gas-density

[7] Q-Max vessels first entered the market in 2009. These vessels are 360 m long and can carry 266,000 cubic meters of gas. Their size precludes them from berthing at most LNG re-gasification terminals.

the end of their learning curve and will increase their capacity to meet domestic and international LNG transport demand, which may further change the shipbuilding landscape (BRS, 2013).

The charter rate can be quite volatile both for short-term and long-term contracts. For instance, the spot price for a median size carrier could vary from $30K per day in 2010 to as high as $160K per day in early 2012 (Mavrinac, 2013), implying a payback time for ship owners between 4 and 20 years. This can translate into a price range of 0.9 to 5 cents per day per mmbtu. Moreover, considering that 0.1–0.25% of cargo (Dobrota *et al.*, 2013) converts to gas each day[8], we can roughly estimate a total shipping cost per mmbtu. For example, putting this into the context of trade between Qatar and Japan, on a round-trip voyage of 28 days (13,000 nautical miles) with an estimated idle rate of 15%, we can derive a shipping cost of $0.31–2.2 mmbtu. The higher end coincides well with the actual figure in 2012 of $2.1/mmbtu (Lucas, 2013). However, the high shipping price created by the Fukushima accident may vanish quickly, as a large number of unchartered vessels are coming online and more ships are available on the spot market. Around 100 new carriers will be completed between 2013 and 2017, with an average capacity of 164,000 cm (74,000 tons LNG). This stands for a 30% increase in international shipping capacity since 2012, or a compound average growth rate of 7%—higher than the expected LNG demand growth of 5–6% in the same period of time.

### 3.5 Regasification Plants

The numbers of importing nations and regasification plants have risen rapidly, and they are expected to keep increasing (as we discuss in the following sections). In 2012, there was a worldwide regasification capacity of more than 649 Mt, which is an increase of more than 150% relative to 2002 (International Gas Union, 2013). The diversity of importers is also augmenting: by the end of 2014, there will be 34 importing nations, up from 11 in 2002. Some reports further estimate a global regasification capacity composed of 160 terminals distributed in 48 countries by the end of 2015 (Lucas, 2013).

The capital cost of re-gasification terminals is less than $1 billion, substantially lower than for exporting liquefaction facilities. In addition, the construction time is only 1.5–2 years, and there are fewer local obstructions. As a result, there is a surplus of regasification capacity on a global level, as is manifested by a utilization rate of only around 37% in 2012 and 2013. Moreover, the increase in number of regasification plants is expected to be higher than that of liquefaction and shipping facilities in the near future, making it unlikely to be a constraint on the development of LNG industry.

However, there are several factors that may pose potential bottlenecks at a regional level. For instance, the utilization rate in India was more than 100% in 2012 due to a strong demand for gas supply, indicating a local bottleneck resulting from a lack of planning and execution capability. Other potential hurdles are capital expenditure (CAPEX) escalation and berthing and storage

[8] This portion of LNG is typically consumed as fuel for the ship. Equivalent to a loss of 1.5–3.75 cents or 1–2.5 cents per day per mmbtu (given a market price of $15/mmbtu in Asia or $10/mmbtu in Europe).

bottlenecks. After the 2011 Fukushima nuclear accident, Japan increased LNG imports to compensate for the decline in nuclear power generation, but the utilization of regasification plants was restricted due of lack of berthing capacity. Storage can provide hedge against market volatility. Currently, there are about 30 Mt LNG storage capacities worldwide, with more than 50% held in Japan and South Korea. Some plants have relatively small storage capacities, which may also limit the utilization rate.

## 4. MID-TERM OUTLOOK FOR LNG

### 4.1 Current Global Demand and Regional Distribution

Currently, natural gas feeds about 21% of global primary energy demand (IEA, 2013). The world consumed 118 trillion cubic feet (Tcf) natural gas in 2013, with a ten-year compound average growth rate (CAGR) of about 2.7% (BP, 2014). LNG trade in the same year was 11.5 Tcf (239 Mt)—about 10% of the total natural gas consumption. The rest of the global gas production was therefore either transported through pipelines (about 21%) or consumed domestically (about 69%). **Table 1** presents the total gas consumption by region, shows a growth rate of total gas consumption by region in the last decade, and allocates LNG by consuming region based on trade destination. The percentage of LNG consumption among all gas demands is still relatively small on the global level, but it is growing fast at 7.8% CAGR in the past ten years.

**Table 1.** Regional summary of natural gas consumption in 2012. Source: BP (2013).

| | Global gas consumption, % | Natural gas consumption CAGR 2002–2012, % | LNG consumption, Mt | LNG share of total gas consumption, % |
|---|---|---|---|---|
| **North America** | 27.5 | 1.4 | 8.6 | 1.3 |
| **S. & Cent. America** | 5.0 | 5.0 | 11.2 | 9.2 |
| **Europe & Eurasia** | 32.6 | 0.6 | 51.3 | 6.4 |
| **Middle East** | 12.4 | 6.6 | 3.4 | 1.1 |
| **Africa** | 3.7 | 5.8 | 0.0 | 0.0 |
| **Asia Pacific** | 18.8 | 6.8 | 168.1 | 36.4 |

The regional distribution of LNG demand is heavily concentrated in certain countries and areas. North America and Europe are major users of natural gas, but their demand grows at a considerably slower rate than other regions. Africa does not yet have any plans for importing LNG in the foreseeable future, but Asia Pacific already uses LNG for more than 36% of its gas demand—a number that is still increasing.

On the sub-region level, eleven major importers accounted for almost 88% of global LNG demand in 2013 (**Figure 8**), with Japan and South Korea accounting for more than 50%. East Asia and Caribbean nations rely heavily on LNG to satisfy their gas demand, followed by European nations (**Figure 9**). Taiwan, South Korea, Japan, Chile, Puerto Rico, Dominican Republic, Spain and Portugal have more than 50% LNG share in their gas demand, with Taiwan, South Korea and Puerto Rico reaching 100%.

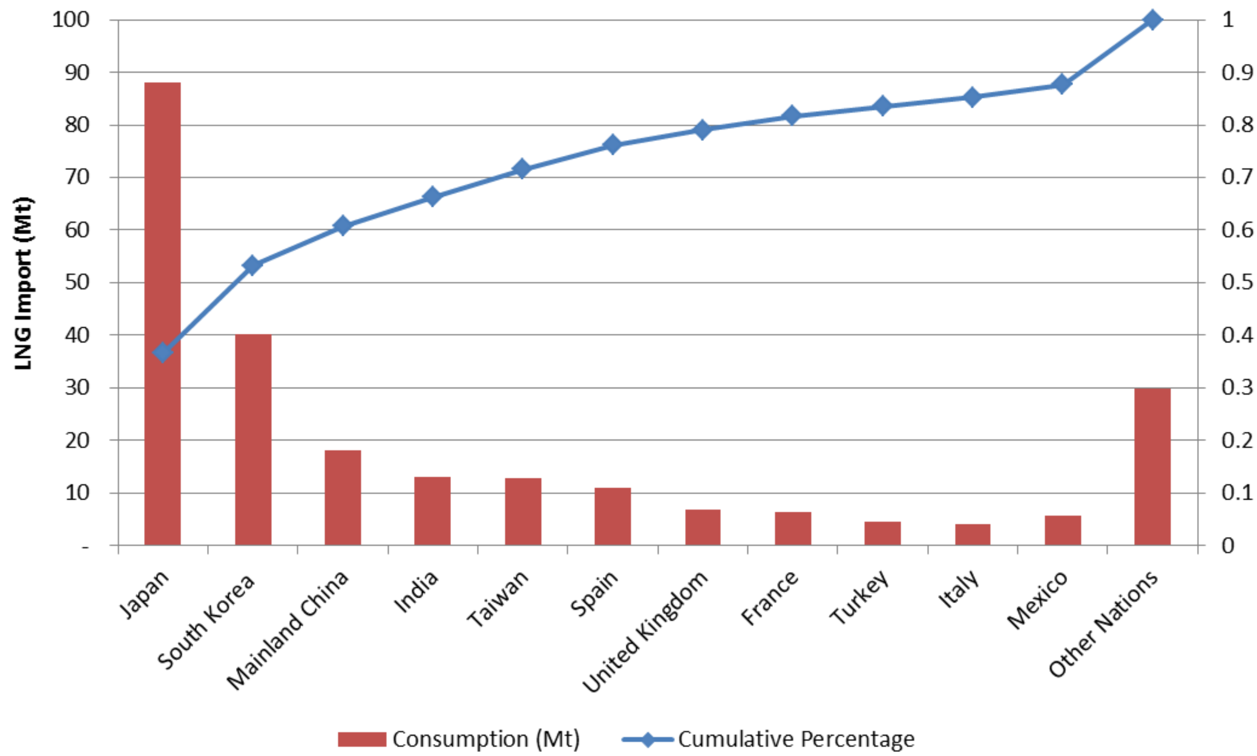



**Figure 8.** Global LNG consumption by country in 2013. Source: BP (2014).

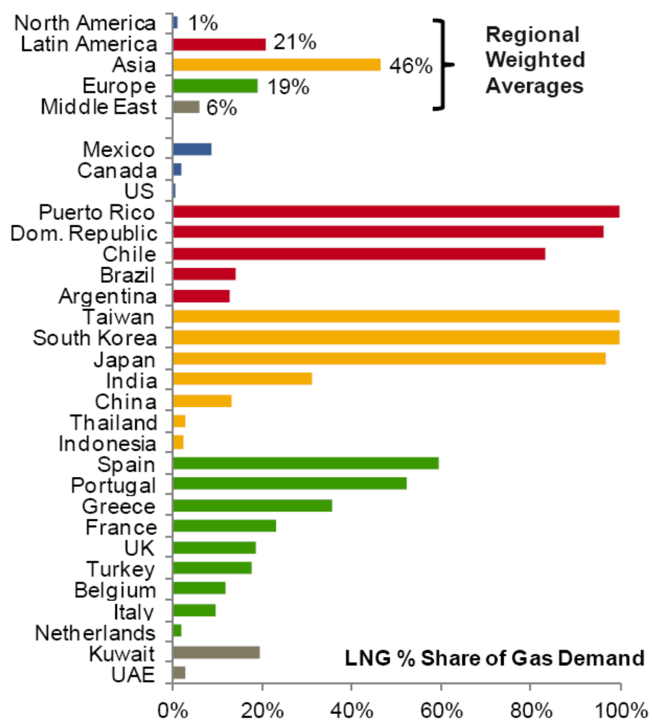



**Figure 9.** The role of LNG in gas markets in 2012. Source: International Gas Union (2013).

### 4.2 Demand Expectations

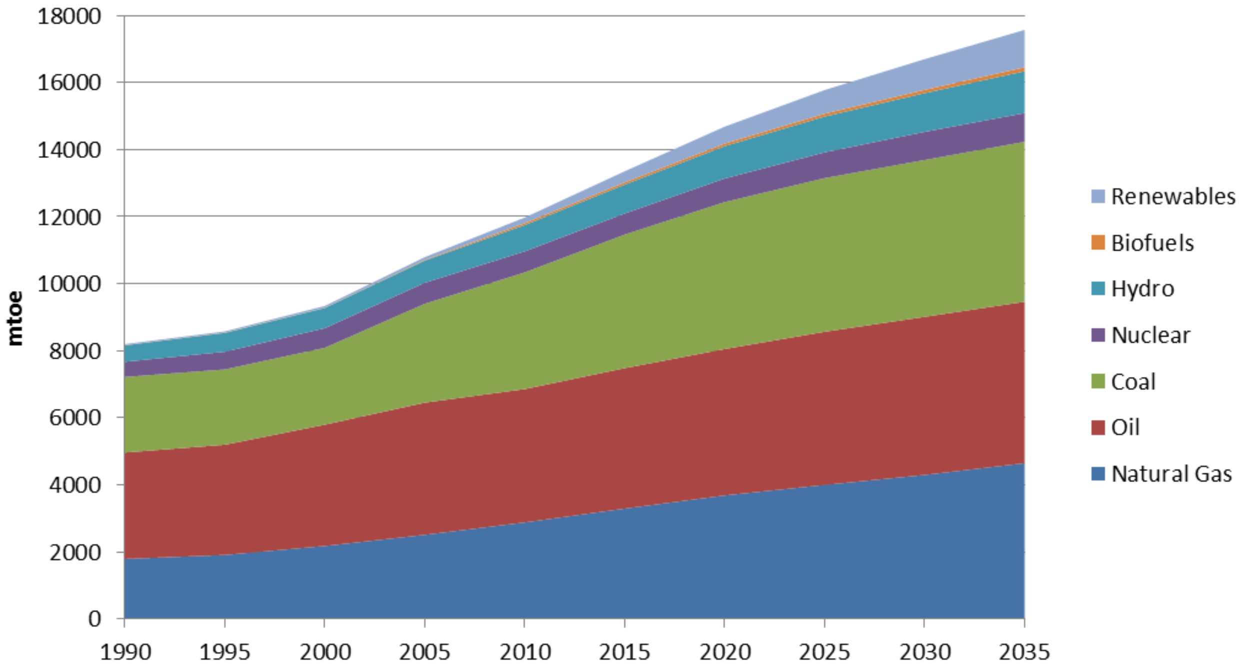



**Figure 10.** Global energy mix trend: history and outlook to 2035. Source: BP Energy Outlook (2014).

In the short to mid term, the market for natural gas is expected to continue growing. Both BP (BP, 2014) and IEA (IEA, 2013) estimate that the global gas demand will rise from the current 120 Tcf to about 140 Tcf by 2020, and further to about 180 Tcf by 2035, which is supported by similar predictions of IGU (International Gas Union, 2013), ExxonMobil (ExxonMobil, 2014) and MIT (MIT Joint Program, 2014). Among the factors that drive the demand high are economic growth, cost of fossil resources, energy supply concerns, environmental considerations, and a slowdown, if not a setback in nuclear power development. As shown in **Figure 10**, natural gas is expected to grow faster than other fossil fuels in the coming decades.

Analysts expect that the annual demand growth rate of LNG will be about 5% to 6% till 2020 and 2% to 3% afterward (International Gas Union, 2013; Ernst & Young, 2012; Deutsche Bank, 2012; Macquarie Equity Research, 2012). This translates into LNG demand of about 340 Mt by 2020 and an annual LNG demand increase of 15–20 Mt.

Developing countries are expected to dominate this new demand. In 2012, Brazil, China, India and Turkey all saw LNG imports increase more than 1 Mt. In 2013, China and South Korea further increased their imports by more than 3 Mt, and Mexico increased by about 2 Mt. Looking forward, this trend is likely to continue. Given the worsening air pollution situation, mainland China may significantly ramp up its LNG import even after a recent deal for Russian gas if there is no meaningful domestic shale gas breakthrough. Similarly, India is expected to have another 5 Mt LNG demand in the next couple of years. Nations such as Indonesia, Malaysia and UAE, who are traditional LNG exporters, will also add to the LNG demand to meet their rapidly growing domestic gas consumption. Indeed, low energy price and rapid economic development has fueled the skyrocketing energy demand in these gas producers, where gas production initially oriented toward export markets is shifting toward domestic consumption.

The picture in developed nations is mixed. LNG demand in the US and Canada will stay low as unconventional gas development continues. In Europe, five nations saw LNG import drop by more than 1.0 Mt in 2012, mainly due to an economic slump and growing consumption of coal and renewable energy. In 2013 this trend continued. This phenomenon is expected to change, though slowly, as a result of efforts to depart from Russia's supplies, counterbalance the dwindling North Sea production, and offset slower nuclear power development. Japan's LNG imports are not expected to grow, due to high prices and reconsideration of nuclear power.

### 4.3 Current Global Supply and Regional Distribution

By the end of 2013, there were 19 countries in the world possessing liquefaction capacity, with Angola as the newest exporter. However, civil war and subsequent unrest in Libya severely limited its capability to export oil and gas in 2012 (Payne, 2013), and in 2013 Libya did not supply LNG despite liquefaction capacity. Recall that in 2013 the total LNG trade volume was 239 Mt while 2013 total liquefaction capacity was 293 Mt; this constitutes a utilization rate of about 81%. In 2014, a new Exxon Mobil LNG plant (with a capacity of 6.9 Mt) in Papua New Guinea started its export operations. This latest project brings the total global liquefaction capacity to 300 Mt. **Figure 11** presents the regional shares of the current (as of mid-2014) global liquefaction capacity.

Qatar, Malaysia, Australia, Nigeria and Indonesia are the five largest potential exporters by far. Combined, their liquefaction plants account for 60% of the current global capacity, which satisfied around two thirds of global LNG demand in 2012–2013. Qatar, Malaysia, Australia and Nigeria are almost fully utilizing their facility to satisfy the strong Asian demand, with utilization rates of 101%, 91%, 91% and 92% respectively in 2012 (IGU, 2013). However, dipping feed gas and strong domestic demand are fettering Indonesia in ramping up its production, resulting in a 56% utilization rate. Other nations that suffer from low utilization of LNG export facilities include Algeria (57%), Egypt (42%) and the US (12% in its Alaska LNG facility) (IGU, 2013).

Currently, two-thirds of global LNG export capacity is in the Middle East region (Qatar, Oman, Yemen and United Arab Emirates) and Asia Pacific region (Indonesia, Australia, Malaysia, Brunei and Papua New Guinea). The Middle East region has the largest capacity of 100.3 Mt, followed by Asia Pacific with a capacity of 100.25 Mt in 2014. Although Russia's LNG in Sakhalin (9.6 Mt capacity) serves and is located in the Asia Pacific region, for further comparison purposes we aggregate Russia's production and capacity data in the Europe & Eurasia region. The current LNG export capacity in Africa (Nigeria, Algeria, Egypt, Angola, Equatorial Guinea and Libya) is 64 Mt. We explore additional capacity, both under construction and more speculative, in the consecutive sections.

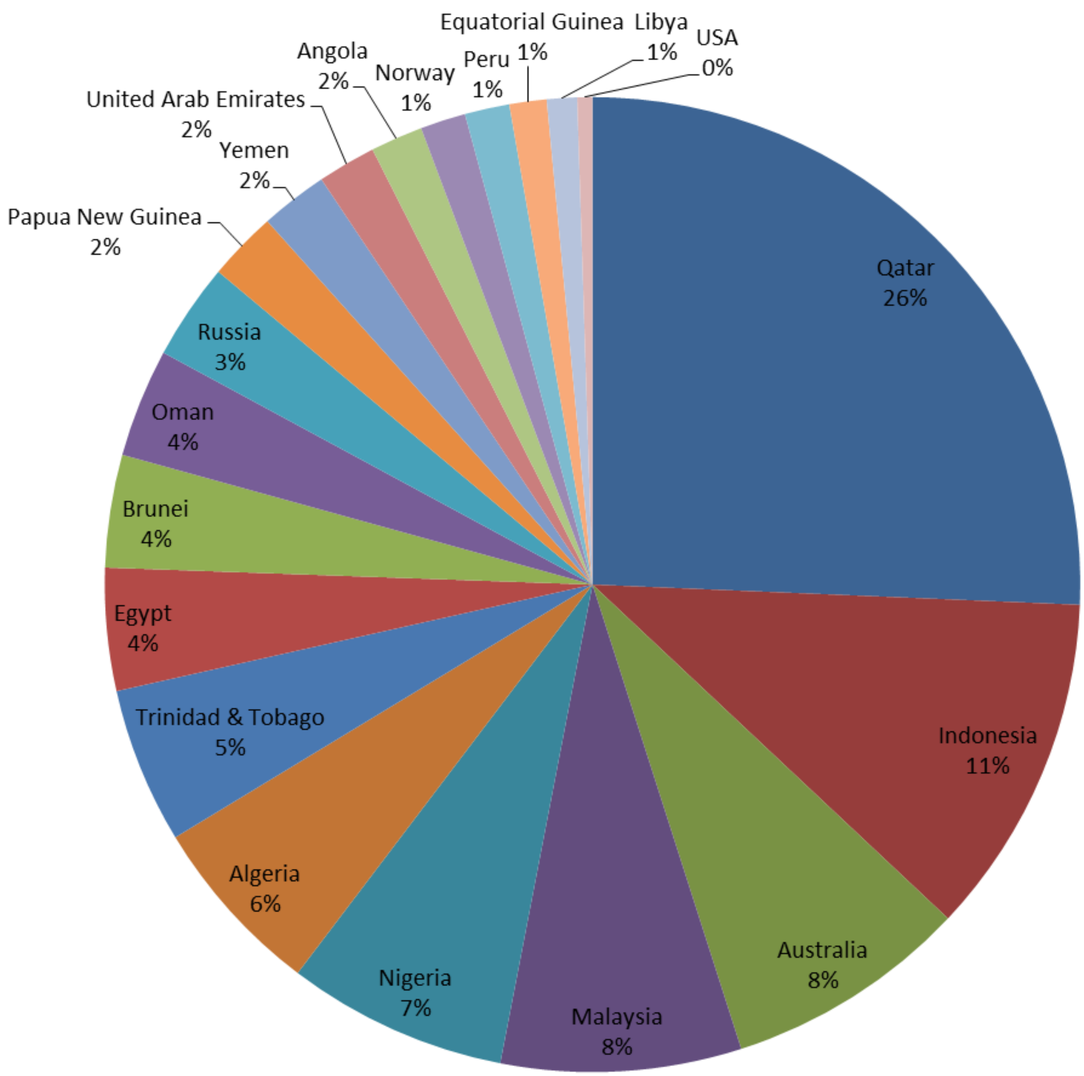



**Figure 11.** Liquefaction capacity by country in 2014. Source: authors' estimates based on IGU (2013) and LNG project websites.

### 4.4 Supply Expectations

Looking forward, it is expected that international oil companies (IOCs) will continue to invest heavily in LNG facilities and remain the major players in LNG supply. The traditional dominant position of IOCs in crude oil production has been challenged by the rise of national oil companies (NOCs), as their technological, financial and project management capability catch up. More importantly, NOCs control more than 90% of the world's oil reserves (Leis *et al.*, 2012); the increasing limits on foreign companies' access to oil reserves, compounded by dwindling new discovery of conventional fields, are forcing IOCs to tap much more expensive resources. Nevertheless, natural gas is still seen by IOCs as an emerging opportunity. Global gas production has increased more than 33% between 2000 and 2012—more than twice the figure of crude oil (14.9%). Meanwhile, global gas reserves increased 34%, also higher than that of oil (32%). More importantly, natural gas resources are widely distributed geographically, and are thus more accessible for international majors.

Under this backdrop, LNG is especially attractive for IOCs. Companies such as Statoil and BG Group already generate more than 20% of their earnings through LNG, and others are catching up quickly. Most NOCs still lack the capability to carry out large LNG projects independently, giving more bargaining leeway for international majors. In addition, LNG projects provide more flexibility (compared to pipeline and domestic consumption), which can potentially increase the overall profitability. Moreover, believing that global oil price will rise in the long run, energy importers are also willing to invest in LNG projects, which can lower the financial cost and help mitigate commercial risks for IOCs.

Driven by these favorable conditions, the world has witnessed a wave of enthusiasm in building new liquefaction plants in recent years. Around 98 Mt of new capacity—which is about one-third of the current capacity (300 Mt)—is currently under construction. Based on data from different sources, we estimate an additional 253 Mt of planned capacity from projects which have already made final investment decisions or are likely to soon reach one. Several projects that qualify as planned capacity are obstructed by geopolitical hurdles (in Iran and Venezuela) and/or by the US shale gas development (Shtokman LNG in Russia). We denote these as deferred capacity, which accounts for 61 Mt. Finally, more than 416 Mt of speculative capacity has been proposed, though with less certainty of being built (**Figure 12**)[9].

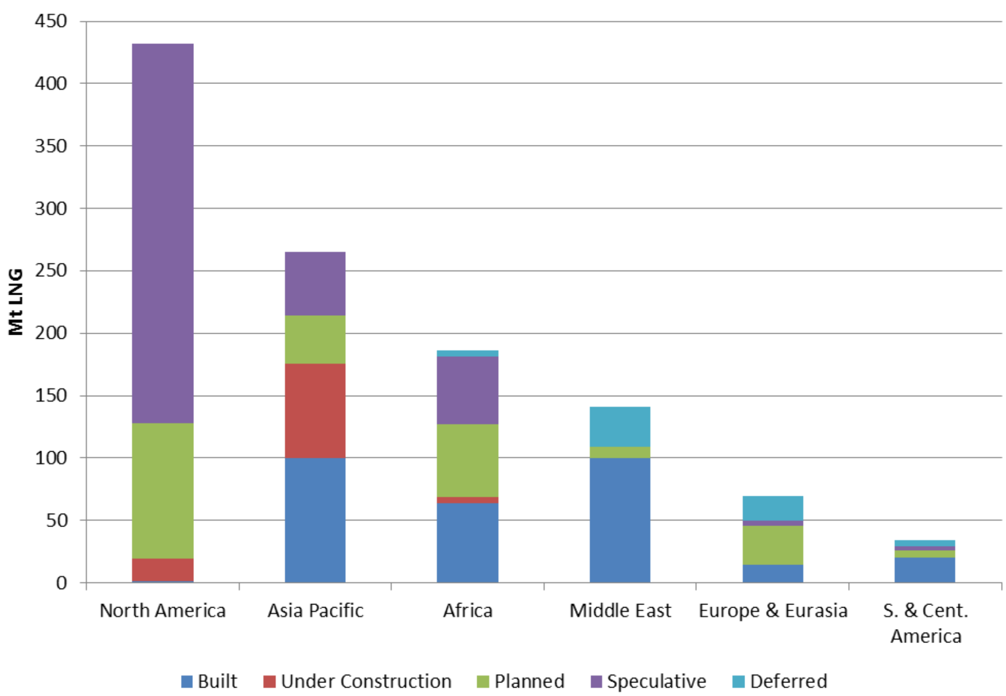
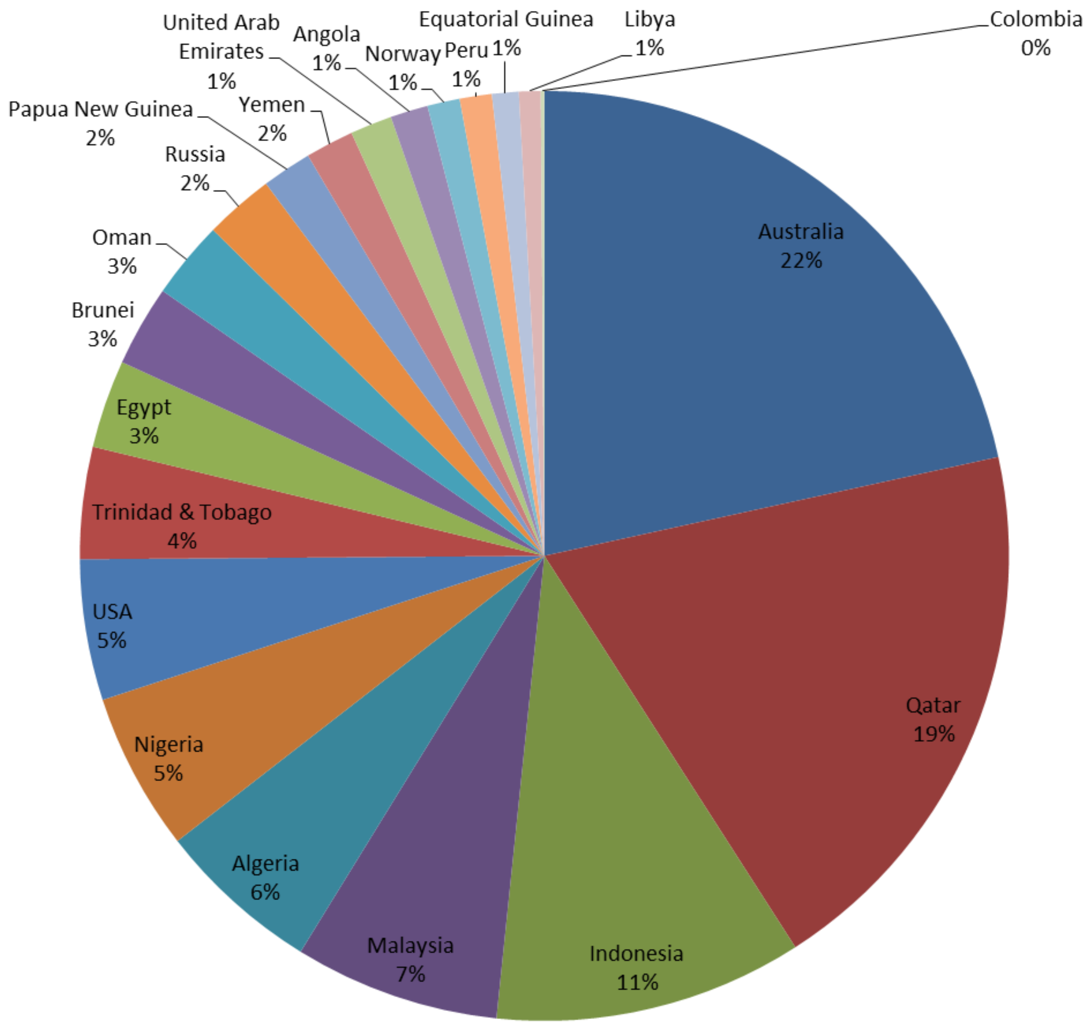



**Figure 12.** Liquefaction capacity by region and development phase

[9] We combined data from various sources, including Global LNG Info, Australian government, International Energy Agent, US Energy Information Administration, Deutsch Bank, International Gas Union and websites of certain LNG project partner companies.

New capacity under construction is concentrated in Australia and North America, while planned projects are more evenly distributed. This will fundamentally change the LNG supply landscape (as shown in **Figure 13**). With several mammoth plants coming online in the next five years, Australia is likely to replace Qatar as the largest LNG exporter. In addition, as a result of their expected high utilization rate, Australia and Qatar will supply half of global LNG demand by 2020. Meanwhile, the market shares of Algeria, Malaysia and Indonesia, the traditional dominating exporters, are expected to drop from 60% to about 20%[10]. Colombia will join a list of the LNG exporting countries, and they will share the remaining 30% market with the other 14 nations.

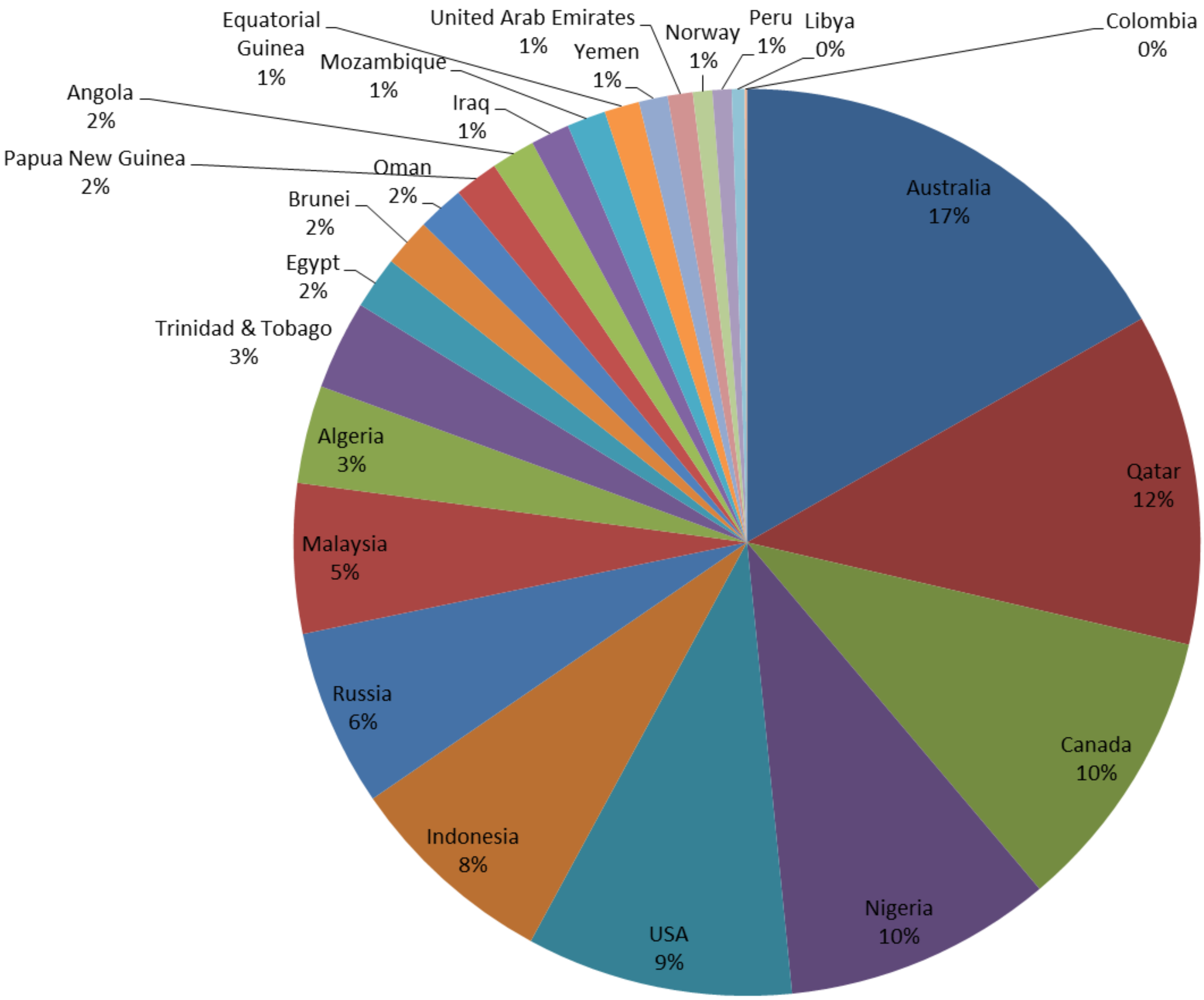



*The total capacity including plants under construction will be 398.37 Mt.

**Figure 13.** Liquefaction capacity by country including plants under construction

[10] LNG exports from Indonesia are expected to decrease due to increased domestic consumption. The Indonesian Arun LNG, with a capacity of 4.15 Mt, is planned for conversion into a regasification terminal to serve domestic needs (not removed as an export capacity as in our calculations here).

There have been some concerns about the potential formation of "Organization of Gas Exporting Countries". However, considering the dominant role of international oil companies and the high market share of OECD nations, it is unlikely that such an organization, if it ever formed, could exert meaningful influence on the LNG market. Moreover, the market power will further shift if planned capacity is taken into account (see **Figure 14**). Canada, the US and Russia will become the third, fifth and seventh largest players in terms of liquefaction capacity, with a combined share of 26% in the world capacity. The worry of over-reliance on Qatari and Australian supply and the subsequent high market concentration can be alleviated.




*The total capacity including plants under construction will be 650.89 Mt.

**Figure 14.** Liquefaction capacity by country, considering plants under construction and at planning stages.

In the short term, only two US projects are likely to be completed before 2020: the Sabine Pass (four trains, 4.5 Mt LNG capacity each) and Corpus Christi (two trains, 4.5 Mt LNG capacity each). These are both projects of Cheniere, which expects by 2020 to export 26.2 Mt LNG annually, with 22.9 Mt sales based on long-term contracts. It is important to note that projects in North America pose the biggest uncertainty on the industry, with a speculative capacity of about 300 Mt (see Appendix D, Table D3). If all built, capacity will be about 15 Tcf (for a comparison in 2013 the total dry gas production in the US was about 24 Tcf). Obviously, not all of them will secure the final investment decision (FID). One reason for this is that the US government is unlikely to approve all exporting licenses due to concern about the potential impact on domestic gas price. The other is simply a lack of commercial viability.

We also consider the Middle East, especially Iran, as another major source of uncertainty. Whether and when the deferred projects will be built in this region largely depends on the political atmosphere. However, given the extremely low production cost and large volumes of gas reserves, potential activities in the Persian Gulf should not be ignored.

**Figure 15** provides the data for historic LNG export capacity and our estimates of the future additions (denoted as 2015E and 2020E in the figure). In the 2015E "newly built" category we include projects under construction with the target completion date of 2014. In the 2020 "newly built" category we include under construction and planned projects with the target completion dates of 2019 and earlier. We assume that all other projects, including speculative and deferred, are built after 2020 (denoted as 2020+E in the figure).

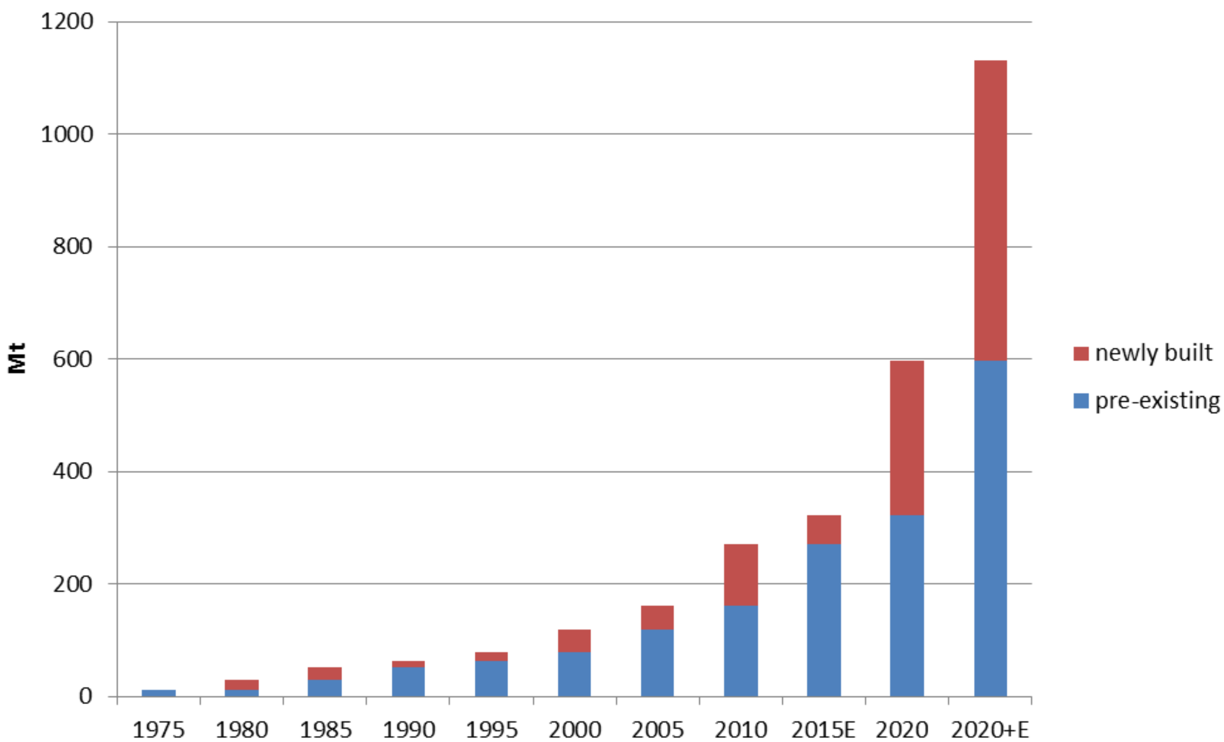



**Figure 15.** Liquefaction capacity increments.

Production cost can be represented by the breakeven Free-on-Board price, illustrated in **Figure 16**. Projects planned or under construction in Africa (AFR) and the Middle East (MES) are at the lower end of the spectrum, while their counterparts in Australia (ANZ) and Russia (RUS) suffer from high costs. Projects in Asia (ASI) and greenfields in North America (USA) are well positioned in the middle, while those in Canada (CAN) and the Rest of Americas (LAM) rest slightly above the middle. For the US, LNG exporters that have received FERC and US DOE permissions show unique cost advantages due to the pre-production of certain ancillaries such as berthing and storage facilities initially designed for importing projects. As a result, the liquefaction plant CAPEX can be just $500 per ton (relatively low, considering that greenfield projects have a global average of $1500 per ton).

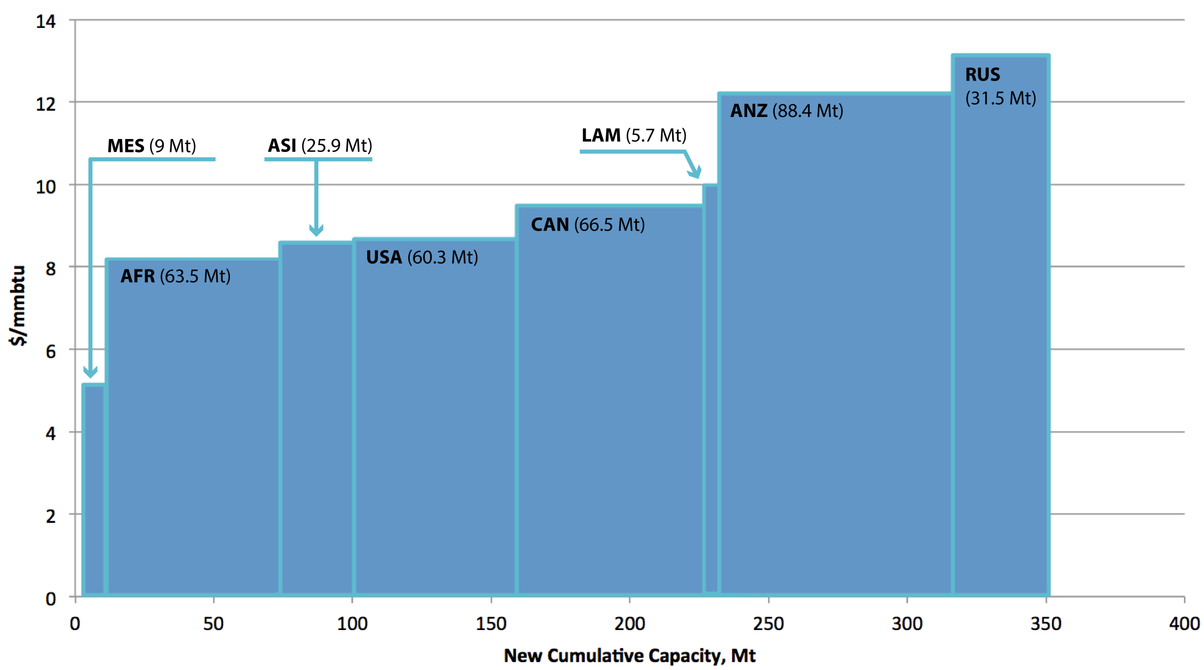



**Figure 16.** Estimated breakeven Free-on-Board price ($/mmbtu) of new projects. Source: own estimates based on Deutsche Bank (2012), Wood Mackenzie (2012), and Jensen (2014a). Note: The full list of regions is provided in Appendix E.

However, after considering the shipping cost, the competitive advantage of US cargos is reduced. The shipping distance from the US to the Asian market is five times that from Australia. Therefore, cargos from the US have to pay as much as $4.3/mmbtu under current spot shipping prices. However, as analyzed in previous section, we expect the spot price to decrease and possibly even converge with long-term contract prices. In addition, the opening of the Panama Canal can significantly shorten the shipping distance—enough to lower the total shipping cost even with a tolling fee (see **Table 2**). On the other hand, projects located in western Canada enjoy a very low shipping cost, driving their overall cost lower than that of the US.

**Table 2.** Estimated shipping distances and costs. Source: Deutsche Bank (2012).

Figure 131: Estimated shipping distances, boil off and costs

| Country from | Port | At Sea (days) | Miles | Charter return ($) | Boil off ($) | Total cost ($) | Cost per mmbtu | *Spot (today)* |
|---|---|---|---|---|---|---|---|---|
| **To Tokyo** | | | | | | | | |
| Australia | Barrow | 8 | 3727 | 1500 | 524 | 2024 | 0.65 | *1.13* |
| Australia | Curtis | 8 | 3860 | 1500 | 524 | 2024 | 0.65 | *1.13* |
| Mozambique | Maputo | 16 | 7594 | 2700 | 1048 | 3748 | 1.20 | *2.07* |
| US GC via Panama | Sabine Pass | 19 | 9209 | 3150 | 1245 | 4395 | 1.41 | *2.42* |
| US GC via Cape | Sabine Pass | 35 | 16754 | 5550 | 2293 | 7843 | 2.51 | *4.29* |
| Canada | Kitimat | 8 | 3954 | 1500 | 524 | 2024 | 0.65 | *1.13* |
| Indonesia | Jakarta | 5 | 2511 | 1050 | 328 | 1378 | 0.44 | *0.78* |
| **To UK Milford Haven** | | | | | | | | |
| US East | Sabine Pass | 10 | 4588 | 1800 | 468 | 2268 | 0.73 | *1.30* |
| Qatar | Doha | 13 | 6091 | 2250 | 608 | 2858 | 0.92 | *1.64* |

*Source: Deutsche Bank Note for cost we assume 0.3% oil off pr day at $14/mmbtu Japan/$10/mmbtu Uk. Charter rates are taken at $75k per day for mid cycle but c$140 at spot. We assume 20 knots per day and that it takes 2 days to load and 2 days to discharge cargoes.*

### 4.5 Mid-term Scenarios

Based on the information available above, we can estimate the overall potential supply and demand relationship in the short- to mid-term. While supply growth can be predicted from the planned and constructed LNG projects, demand growth is more uncertain. Here we rely on two simple demand scenarios (see Section 4.2 for a discussion) where LNG demand grows either at 6% annually (Demand High) or at 5% annually (Demand Low). Obviously, the realized LNG flows will equate demand and supply, so the resulting quantities of demand and supply will be the same. Here we refer to expectations regarding future LNG supply and demand. As shown in **Figure 17**, the global average utilization rate of liquefaction plants is likely to drop below the historical average, mirroring the fact that liquefaction capacity expansion will outpace the potential demand growth.

However, the global liquefaction utilization rate may not be a good proxy to represent the tightness of the market, since it fails to distinguish between effects such as dwindling production of existing gas fields, decreasing exports due to higher domestic demand, and aging/retiring of old liquefaction plants. A better way is to treat the existing and newly built capacities separately. To address it, we assume that only projects that are planned or under construction can enter the market by 2021. After taking different utilization rates into consideration, we notice that global supply is abundant in the short run (see **Figure 18**). But from 2018 on, there is more uncertainty associated with both demand and supply side. This uncertainty can in turn reinforce our belief that speculative projects are unlikely to come online during this period since investors tend to wait and see how the market would roll out.

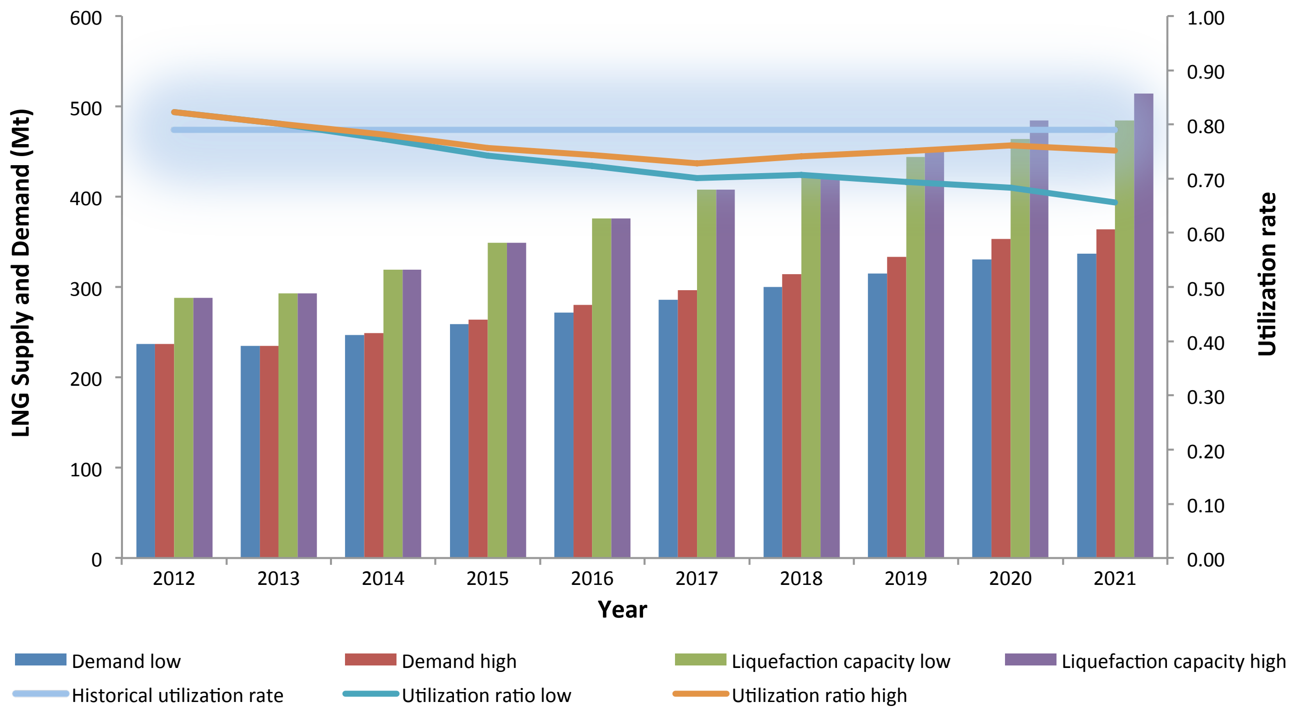



**Figure 17.** Liquefaction capacity utilization rate, 2012–2021.

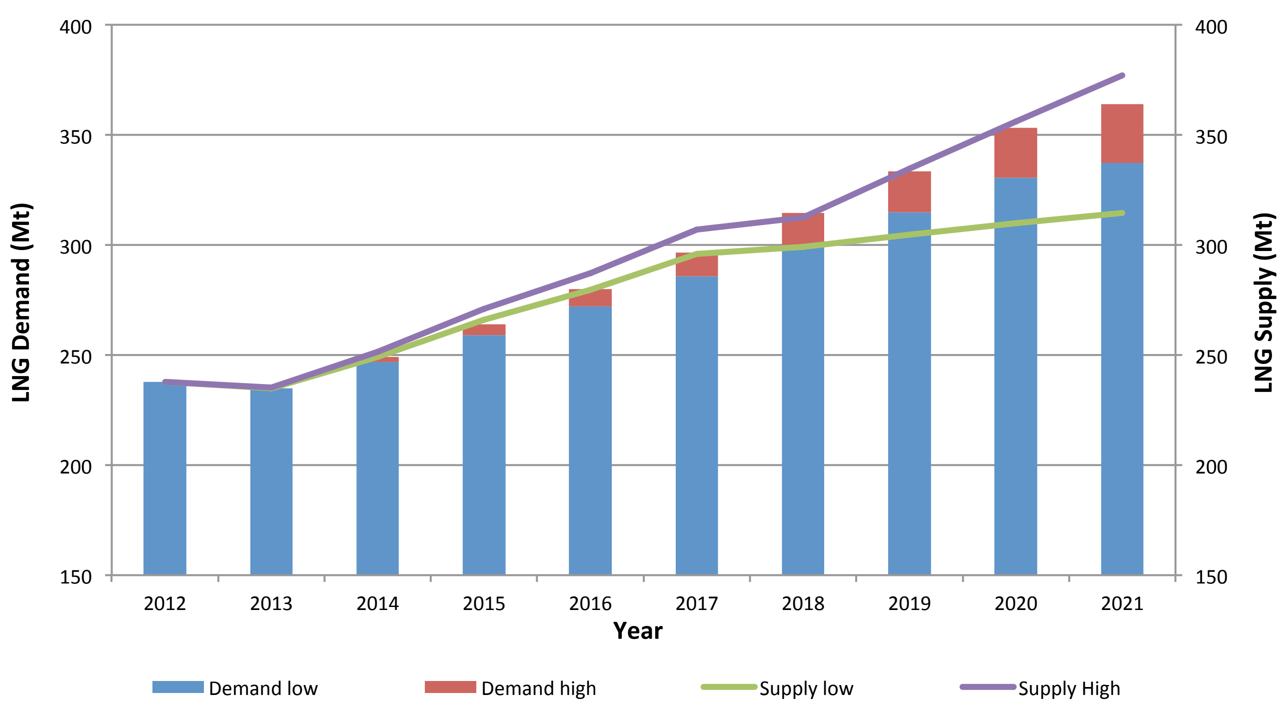



**Figure 18.** Short to mid-term potential demand and supply.

There are two caveats when interpreting this graph. First, we assume no further delays and cancellations of projects under construction, since many companies have already adjusted their estimated completion time according to the recent trend. But this heavily depends on how well companies have learnt from previous lessons. J.P Morgan's analysis shows that 34% of all projects in the 2000–2010 period were delivered behind schedule, and 38% were over budget (**Figure 19**); if execution efficiency fails to improve or project managers have underestimated difficulties, then new exporter projects will delay, only benefiting the existing suppliers. Second, we assume a normal utilization rate. However, some exporters can try to exert their market power through strategically producing less. We consider this to be an unlikely option because of numerous existing suppliers, but some Australian projects may still underutilize.

**Figure 20** shows three additional scenarios based on the high supply scenario:

- **Scenario 1.** Qatar ramps down its LNG utilization rate from 101% to 90%, which is close to its pre-Fukushima figure (92%).
- **Scenario 2.** One third of new projects experience a delay of 1 year.
- **Scenario 3.** A combination of Scenarios 1 and 2.

These factors can significantly influence or even reverse short- and mid-term expectations for the LNG market trends.

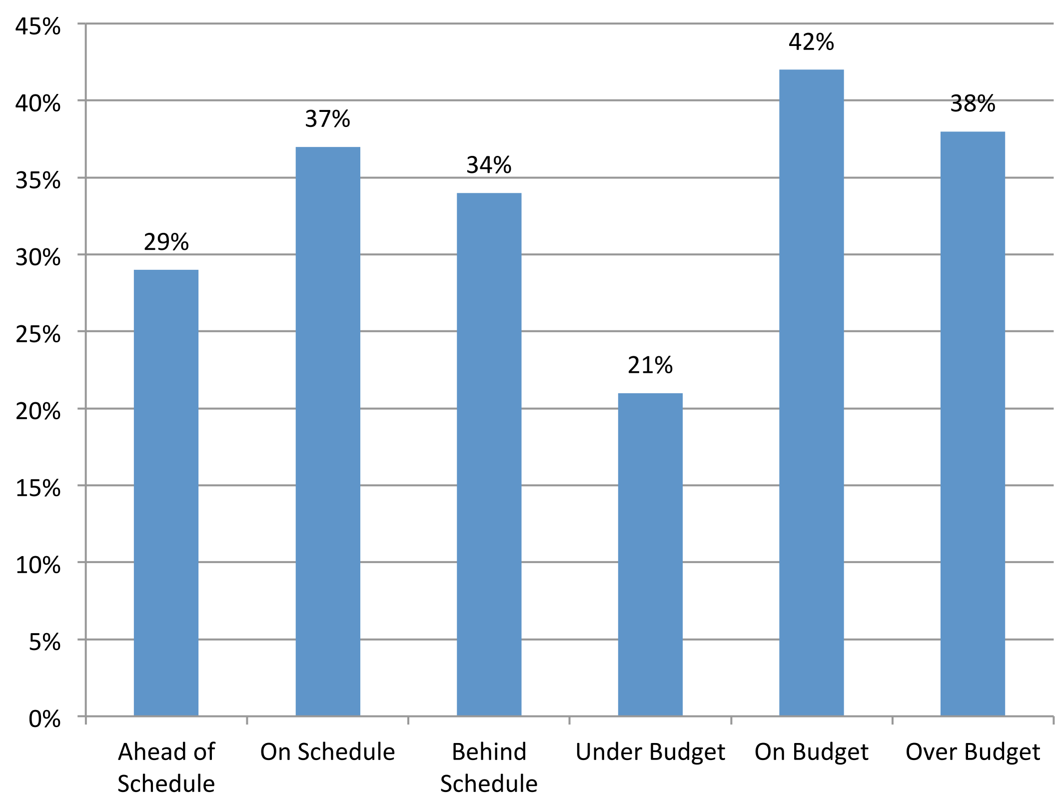



**Figure 19.** Global LNG project execution efficiency from 2000 to 2010. Source: J.P. Morgan (2012).

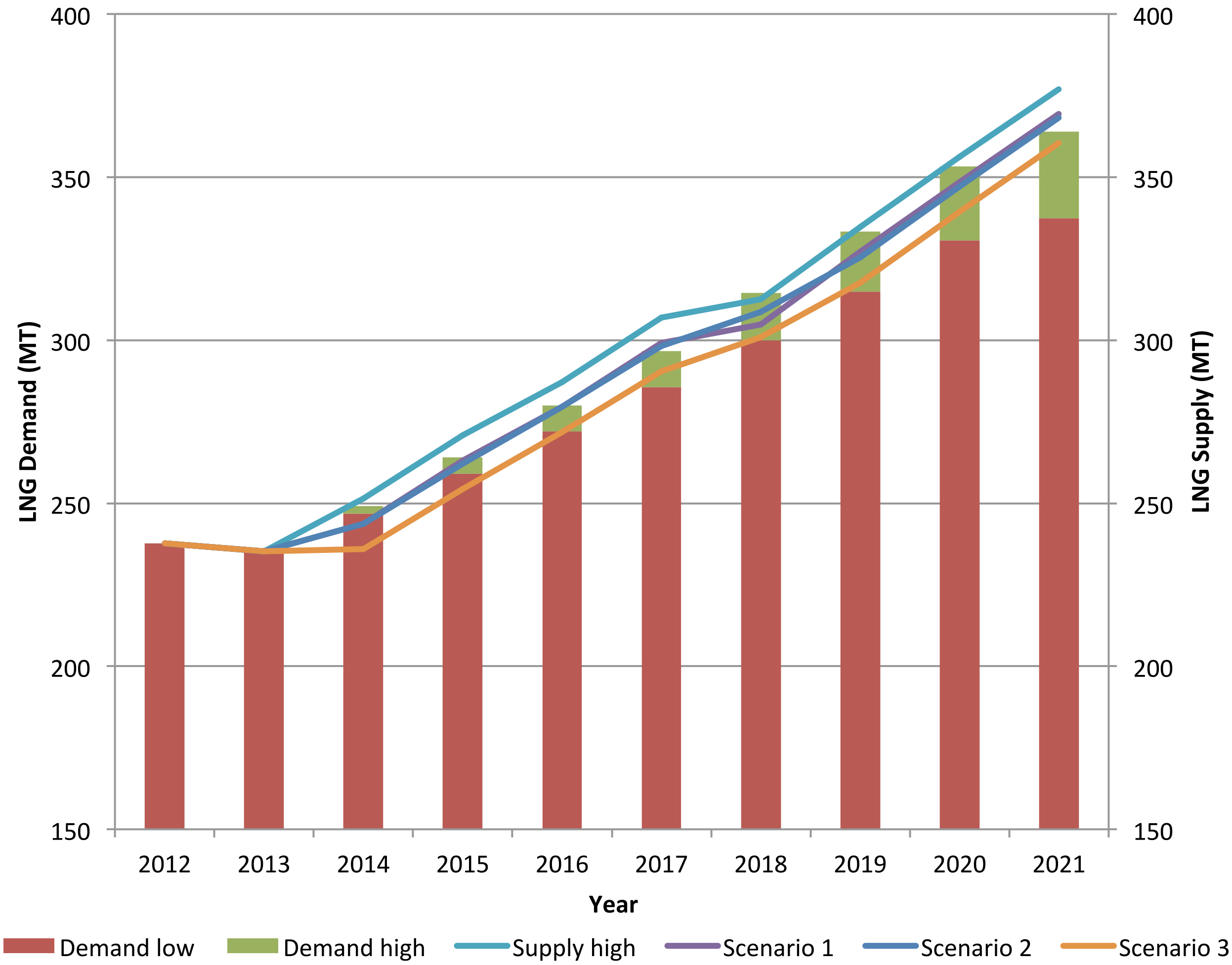



**Figure 20.** Scenario analysis of delay and market power.

The volume and pattern of inter-basin trade flows have experienced dramatic changes since the first global cargo was delivered. While the percentage of Middle East–Atlantic trade keeps dwindling, the linkage between Middle East and Asia is strengthening. The importance of trades across the Pacific Ocean has decreased since the late 1990s, but is expected to increase again in the coming years, as the focus of LNG development shifts to this area.

East Asian importers share a characteristic that differentiates them from others: they stress the importance of diversification and balance between different exporting regions and nations. While other importers usually keep a supplier list of three to five nations, Japan imports LNG from every exporting country. China and South Korea also trade with more than ten exporters. This strategy is especially favorable for new entrants on the supply side, as their cargos provide extra value to these nations and are more likely to secure investment.

One phenomenon that has a game-changing implication and deserves a closer look is the fast-developing spot market, which now accounts for more than 30% of total LNG trade—significantly higher than the 5% ratio only 10 years ago. In particular, the volume of spot cargo reached 73.5 Mt in 2012, which is 12% higher than that of 2011 (International Gas Union, 2013).

Admittedly, there are short-term factors that can partially explain its rapid growth, such as the Fukushima accident and unexpected low demand in Europe. However, there are several reasons why this long-term propellant should not be overlooked.

First, increased linkage between different regions will give sellers and buyers more confidence in entering the spot market. As the number of suppliers and consumers keep increasing, both sides will have more options when choosing trading counterparts, and will thus enjoy higher trading flexibility.

Second, the formation of new trading hubs will provide more liquidity and information that are critical for market players. Singapore, which is already a pricing hub for oil products, opened a re-gasification terminal in 2013. With the intention to become the regional trading hub, plans exist for building another one. Companies such as BG Group, Gazprom, Shell, ConocoPhillips and BP have been actively building their trading capability there. Similarly, Shanghai is likely to be a trading center in East Asia, given its advantageous location and favorable policies.

Third, increasing popularity of divertible contract options facilitates arbitraging activities. Under such terms, exporters and importers can share the profit when cargos are diverted to markets that offer higher prices, which was not a common practice even five years ago. Divertible contracts can also improve efficiency. Some exporters sign contracts on cargo swaps with each other to minimize shipping costs, as can be seen in a recent transaction between Gazprom and Sonatrach.

Finally, exporters have also realized the potential benefits of reserving flexible capacity. One extreme example is the recently-completed 5.2 Mt Chevron Angola LNG—the world's first exporting project solely devoted to the spot market. This new business model may be risky, but not necessarily unviable as recent tight markets rewarded risk-taking players well. Compared with many other exporters, Qatar and Nigeria gained higher profits after the Fukushima accident, as they accounted for almost half of the spot exports—most of which were directed to Asia. Their example may lure more potential exporters to lower the percentage of long-term contracts.

In conclusion, the percentage of spot volumes gradually will go up. However, given the strong conservative atmosphere in the industry, long-term contracts will continue to be the dominant trading mechanism. The emergence of the new contracts, especially the revisit to pricing terms, has attracted the most attention in this domain. With the advent of the shale gas revolution in the US and the subsequent lower price at Henry Hub, Asian importers started to demand a gas-on-gas competition in lieu of the oil-indexed contract.

Indeed, the contract terms plays a central role in LNG trade and are heavily influenced by relative bargaining power and market expectations. For instance, in the early 2000s, when supply was abundant, Indonesian and Australian LNG companies signed long-term contracts with China and India that have only 30% oil linkage—significantly lower than the industry norm of 85% in previous periods. However, the contracted price can reach full oil-parity when the bargaining power shifts to the sellers, as in the case of post-Fukushima period.

In our view, the necessity for oil-linked contracts is gradually disappearing and the potential favorable supply situation in the short term may give buyers an opportunity window to renegotiate the pricing formula. When there was no liquid spot LNG market, oil price could serve as a proxy of the value of LNG cargos. But as new trading hubs emerge, this condition no longer holds. Oil prices are expected to be systematically higher than those of natural gas, so buyers are unlikely to agree on such an arrangement. With the deregulation and marketization movements deepening in many importing countries, buyers will only become more price-sensitive. Moreover, unlike traditional LNG importers such as Japan and Korea, new buyers are more flexible in choosing between different energy sources (for example, China has an option of LNG and pipeline gas imports). This optionality will give the buyers more bargaining power.

At this time, there is a lower linkage between the production costs of crude oil and natural gas. On the supply side, historically, oil and gas were competitive fuels for power generation. However, oil's share of global power generation has dropped from 25% to less than 5%. Meanwhile, natural gas is becoming an increasingly important power generation fuel. As a result, the physical connection between these two commodities has broken. Some experts even argue that coal prices plus carbon prices can be a more relevant indexation than an oil-linked one.

Stronger linkages between regional markets and more direct competition between pipeline and LNG will be the likely long-term trends, and it is becoming increasingly difficult for suppliers to stick to oil indexation without better arguments. Consequently, we expect some amendments to the current pricing terms in the short to mid term; in the long term, hub indexation should ultimately dominate.

Regional prices have differed widely. The monthly average price of natural gas in the East Asian market stayed above $15/mmbtu from the Fukushima accident until the summer of 2014, while the spot price in the US stayed between $3–5/mmbtu in the same period. The spot price in Japan reached $20.50/mmbtu in February 2014, almost five times higher than its US counterpart. Trading bottlenecks are limiting the convergence of prices. More than 60% of the world's oil is traded on the global market, making any regional price imbalance short-lived. In comparison, as we have discussed above, only about 30% of gas is traded cross-border—two thirds of which are transported through pipelines, offering limited destination flexibility. Among the remaining 10% of trades that are transported via LNG ships, only 30% of those are on the spot market. The remaining 70% long-term contracted trades offer little help to converge the regional prices. Besides the small volume, a tight shipping market has also limited the profitability of arbitraging between basins, dampening the enthusiasm of traders.

The price disparity is unlikely to disappear in the near future, but may decrease as more supply comes online or due to a reduction in demand. In the summer of 2014, spot LNG prices in Asia dropped to $10.50/mmbtu. This price decrease surprised many analysts, and it was attributed to an early LNG supply from a newly built Papua New Guinea plant combined with lower than expected demand from Japan, South Korea and China. The price is expected to recover by winter 2014 to the levels of $14–15/mmbtu, but this shows that the LNG market is changing constantly and can be influenced by many factors, making any predictions error-prone. In the next section, we will discuss some of the most important uncertainties that can change the landscape of LNG industry overnight.

## 5. FACTORS INFLUENCING LNG MARKETS

The previous analysis presents our understanding of the LNG industry and our best estimation of short- and mid-term expected developments. However, a general atmosphere of secrecy in the industry leads to poor availability of critical information in a timely manner, which may obscure our current understanding of the market activities. In the section below, we discuss some of the major uncertainties that can change our current expectations for the LNG industry. Most of the uncertainties have implications in the longer term, but some may also take place just within years.

### 5.1 Demand Growth

As discussed previously, market analysts tend to agree that the growth rate of global demand will slow down in the long run (beyond 2020). Usually, a slower economic growth, higher energy efficiency and liberalization of emerging energy markets are attributed to that expectation. However, there are signals showing that demand might be lower than the expected 5–6% growth even to 2020.

China is considered by many as one of the most important new LNG markets in the world, as natural gas makes a good potential substitute for coal and oil in China's attempts to reduce its air pollution and carbon emissions. However, a movement to natural gas in China has been challenging. First, economic growth is slowing down. The annualized seasonal nominal GDP growth rate has declined from the highest point of 12.1% to the current 7.4% (NBS China, 2014), and it remains to be seen if this trend will continue. As manufacturing and construction industries are the dominating energy consumers in China, slower growth implies less than anticipated overall energy demand. Moreover, the end users will become more sensitive to energy price increase, which will be transmitted to the fuel selection process. As natural gas is currently the costly option in terms of power generation in China, it will likely experience more downward pressure. Recent natural gas reform also raised domestic natural gas prices for all users, which may affect demand.

The estimation of Chinese demand for LNG in some of the former market research reports are based on the recent Five Year Plan of China, which requires a high penetration of natural gas in the total energy mix (from 4.3% to 8.3%). Many experts interpreted this requirement as a strong signal of support for LNG imports. However, informed market players should not rely heavily on such conclusions. To begin with, these numbers in the Plan are not strictly binding and should be considered more as a guideline rather than a strict policy. The final outcome will not only depend on the determination of the policy makers, but also on the specific circumstances in the global and domestic market. More importantly, the overall ratio target was replaced by a domestic production target in the final version of the plan. At this point, it is less likely that this target can be translated into new LNG demand if the production target is not met. Finally, the essence of this plan is to develop a reliable market structure, which in the end could encourage domestic gas production. In this sense, the Plan may not be as good news for LNG exporters in the long term as it might appear.

Obviously, demand uncertainties exist in other regions as well. For instance, the pace at which governments deregulate and remove subsidy from gas markets remains to be seen in many developing countries. Governments currently supply natural gas at a price much lower than spot LNG cargos, a practice that is partially responsible for rapid gasification in some regions. But this paradigm may not be sustainable. Malaysia, India, China and Argentina have all increased their domestic price to reflect higher LNG import prices. If this trend continues, the growth rate of LNG demand will slow down further in comparison with the base case.

The recent efforts by Japan's administration to restart its nuclear plants are also adding to the uncertainty on the demand side. Indeed, Japan has every reason to reduce its reliance on LNG given its high price. In the first quarter of 2012, Japan imported 18.6% more LNG cargos than a year before, but payment increased 49.2%. These high energy prices are hampering Japan's competitiveness and economic development. However, a general lack of confidence in the nuclear industry as well as its regulators makes restarting nuclear generation difficult. Therefore, Japan is trying to begin the process of restarting from its regions with the least resistance. Whether some of the most secure plants can get approval to restart may have limited influence on short-term market dynamics, but can have important implications on long-term expectations of nuclear energy's return to Japan.

### 5.2 Technological Development

The LNG industry is pushing its technological boundaries. Improvements in safety, efficiency and flexibility have been contributing to an increasing popularity of natural gas for decades. However, emerging technologies can also pose uncertainties on both incumbent and new entrants. Among all recent technological improvements in the LNG value chain, some analyses identify floating LNG (FLNG) as a technology that may have a substantial impact on the industry if proven to be viable.

FLNGs are vessels that can process and liquefy natural gas on board. This technology is superior to traditional land-based liquefaction complexes in several ways. To begin with, it enables indoor construction that provides a more controlled environment. Many difficulties that traditional developers have to deal with will no longer be relevant; it avoids many lengthy and painful regulatory procedures related to land use, and local landscape concerns and protests are also lessened. Consequently, the risk for investors that are associated with safety, cost and schedule will be minimized. Secondly, the construction time is expected to be only two thirds of the typical onshore plant. This feature can provide companies with more temporal advantages to adjust to the fast changing market. Thirdly, the flexibility of FLNG gives it the opportunity to monetize stranded resources. Offshore fields that are too small or too far away to certify a traditional liquefaction complex can be tapped by FLNGs. This feature is especially relevant for the LNG industry, since the size of new gas discoveries is shrinking. Once a production field is exhausted, the vessel can move on to the next target. Finally, FLNG provides the opportunity to reduce greenhouse gas emissions by avoiding gas flaring and re-injection in many offshore oil fields.

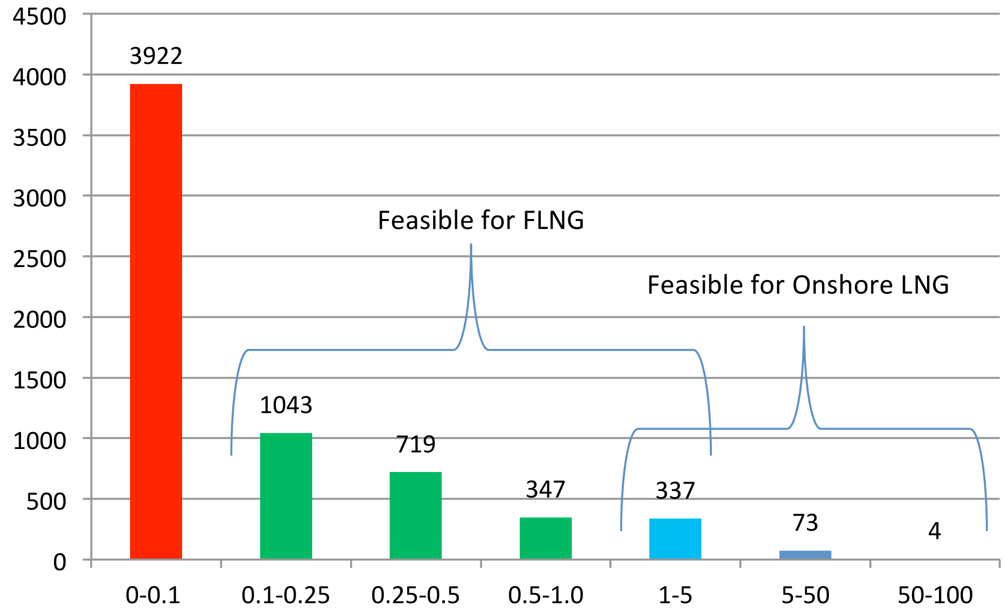



**Figure 21.** Number of gas fields of different sizes. Source: J.P. Morgan (2012).

If FLNG is proven to be viable, it can have non-negligible influence on the LNG industry landscape (Jensen, 2014b). There are plenty of small to medium natural gas fields containing a great amount of resources (**Figure 21**). The most recent estimation is that about 1400 Tcf natural gas resources are stranded in offshore oil and gas fields, accounting for more than one third of the total offshore natural gas reserves (Attanasi and Freeman, 2013). Moreover, given the much wider geographical distribution of these fields, producers will have more choices and thus be less restricted by local political uncertainties than before.

However, up to now, FLNG is still an unproven model. Critics are concerned about its huge capital investment as well as high operating and maintenance costs, which may put its commercial viability at risk. Moreover, even though the vessels are engineered to withstand harsh environments on the ocean (e.g. super typhoons), it remains to be seen if extreme weather conditions will have any influence on the real production. Currently, more than 120 Mt FLNG capacity has been considered worldwide, distributed among 30 floating liquefaction projects (Yep, 2014). But most of these capacities are still speculative. Every eye is on the performance of those pioneering projects and hopefully definitive results will be available soon.

The world's first FLNG project is likely to be completed by 2015 off the Colombian coast. The vessel has a capacity of 0.5 Mt and is owned by Excelerate Energy and Pacific Rubiales Energy. But the industry is paying more attention to another Australian project: Shell's Prelude LNG, which is to be completed in 2016 and come online in 2017. This gigantic vessel is estimated to cost \$11–12 billion and will be stationed near Northwest Australia, 200km offshore. It will produce 3.5 Mt of LNG, 1.3 Mt of condensates and 0.4 Mt of liquefied petroleum gas during the 25-year lifetime of the field. **Table 3** provides a list of some potential FLNG projects.

**Table 3.** Some potential FLNG projects. Source: J.P.Morgan (2012).

| Country | Project | Project sponsors | Project status | Capacity (MT pa) | On stream |
|---|---|---|---|---|---|
| **Australia** | Prelude LNG | RD Shell 100% | Under development | 3.5 | 2017 |
| | Bonaparte LNG | GDF Suez 60%, Santos 40% | Under review – FID 2014 | 2.0 | 2019 |
| | Cash Maple FLNG | PTTEP (50%), PTT (50%) ** | Under review – FID 2012 | 3.6 | 2017 |
| **Australia / East Timor** | Sunrise FLNG * | Woodside 33.44%, RD Shell 26.56%, ConocoPhillips 30.0%, Osaka Gas 10.0% | Under review | 3.6 | 2018 |
| **Brazil** | Santos FLNG | Petrobras 51.1%, BG 16.3%, Repsol 16.3%, GALP 16.3% | Under review – FID 2013 | 2.7 | 2018 |
| **Indonesia** | Abadi FLNG | Inpex Masela 60%, RD Shell 30%, PT Energi Mega Persada 10% (PT EMP) | Under review – FID 2013-14 | 2.5 | 2019 |
| **Iraq** | Khawr al-Amaya FLNG | RD Shell 50%, Mitsubishi 50% | Under review – FID 2013-14 | 2.0 | 2017 |
| **Malaysia** | Sarawak FLNG | Petronas 100% | Under review – FID 2012 | 1.0 | 2016 |
| | SK 205 FLNG | Petronas 50%, Petrovietnam 50% * | Under review | 3.0 | 2019 |
| **Nigeria** | Progress FLNG | Mitsubishi, Peak Petroleum * | Under review | 1.5 | 2017 |
| **Papua New Guinea** | Gulf FLNG | Liquid Niguini Gas (InterOil 52.5% + Pacific LNG Operations 47.5%), Flex LNG ** | Under review – FID 2012 | 2.0 | 2017 |
| | TBC | Hoegh LNG, DSME, Petromin ** | Under review | 3.0 | 2019 |
| | | | **Total potential capacity** | **30.4** | |

### 5.3 Social and Political Swing of Suppliers

Compared with the demand side, regulatory and political uncertainties in the supply side have even more important implications for the LNG competitive landscape and pricing in the future. The cumbersome and costly struggle in the host countries can be one of the largest threats to the successful development of LNG projects. These issues may arise even in advanced economies with matured market establishments. The US gives a good example of how such an uncertainty can unfold. The shale gas revolution turned the US from a net LNG importer into a potential major exporter overnight. Low domestic wholesale price and tight international markets are pushing companies to build LNG plants to capture this arbitrage opportunity. Moreover, extensive existing infrastructure and existing regasification investment provide these companies with extra advantages in terms of upfront investment cost.

However, the impact of LNG export has become a very controversial and politically sensitive topic. Domestic industries such as petrochemicals, steel and fertilizers, who benefit from the lower gas price, are worried about loss of competitiveness once the significant export is materialized. Concerns about excessive shale gas production and local disturbance are also mixed in the debate. Therefore, even though economists find exporting a good option that can improve overall social welfare, there are many strong arguments based on local employment, taxation receipts and environmental protection.

Political pressure from objectors is channeled through the licensing process. To export LNG from the US, one has to at least acquire approvals from the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). The FERC approval focuses on environmental impacts and safety issues related to the construction of liquefaction facilities. Though less politically controversial, this process can be very expensive and lengthy. The DOE license gives the exporter the permission to export LNG to nations with or without free trade agreement (FTA).

While the Natural Gas Act mandates that the DOE must approve export application for FTA nations “without modification or delay” (which almost guarantees approval), it is not the case for export applications supplying non-FTA nations. DOE must determine the impact of such activities on the "public interest" in non-FTA cases. The default assumption is positive, unless proven to the contrary; however, this determination can be later modified, suspended or even rescinded under certain procedures, and in practice, DOE tend to be very prudent in making the decisions to avoid potential controversies and confusions.

Potential social and political swings in other suppliers such as Indonesia, East Africa, and the Middle East are also sources of uncertainties. For example, LNG exports are a politically sensitive topic in Indonesia, mainly due to its competition with domestic gas demands. Subsidies and economic development are encouraging the growing appetite for energy in this nation. But regulatory hurdles are impeding necessary increases in production to meet such demands: price control and corruption are slowing down foreign and domestic investment on production, infrastructure and exploration activities; and the recent decision by the Constitutional Court to dissolve the oil and gas regulator BPMigas further adds to investors' worries on unstable regulatory regimes. As a result, there has been precedence for Indonesian companies to buy spot LNG cargos to honor export contracts. According to the estimation of its energy regulator, the country will need to start importing LNG by 2018 to meet domestic demands. Under this backdrop, whether Indonesia will force companies to stop exporting LNG may be a major uncertainty worth a closer look, especially given the unpredictable track record of its government. Indeed, the Ministry of Energy Mineral Resources recently announced that it is considering a moratorium on gas exports—a statement that was later retracted.

Domestic supply is also affecting other exporters. For instance, in East Africa, Tanzania is still waiting for more proven resources before sanctioning export projects to ensure domestic supply. Qatar also at least temporarily stopped construction of new capacities after the last LNG plant came online in 2011. According to Qatari officials, the moratorium—scheduled to be revised this year—was intended to ensure sufficient availability of gas resources for future generations.

Domestic political and fiscal uncertainties may also put ambitious gas export plans into question. In Mozambique, the hot spot of recent gas discoveries, more than half of the population lives under the poverty line (World Bank, 2009). Extreme poverty is both the result of and the fuel for instabilities. Concerns over security have increased, which may delay the investment construction process. Such concerns can compound with other regional risks, such as pirates from Somali or religion extremists in Africa[11], that can threaten operation and transportation practices. In Nigeria, the dispute and conflicts between local and central government on profit sharing has impeded its oil exports, and such influence is also expanding to the LNG industry.

In addition, the sheer size of a potential LNG project can be challenging for the institutional capability of under-developed countries. The estimated capital expenditure for a 10 Mt LNG project, including both upstream production and liquefaction, is more than $27 billion in the East African region (Ellis and Heyning, 2013). But in 2012, the GDP of Mozambique and Tanzania were only $14.6 billion and $28 billion, respectively. Therefore, these nations must rely on huge

[11] For instance, the terrorists who recently attacked Algeria LNG plants.

investment from international companies. It remains to be seen how their governments can strike a balance between attracting foreign investors and sharing the profit of the project[12].

Finally, international tensions are rendering new projects in Iran as a wildcard. The Comprehensive Iran Sanctions, Accountability and Divestment Act (CISADA) has delayed the development of some of the largest gas fields in the Persian Gulf. Although there are signs that the Iranian government is making progress on relieving the tensions, great uncertainties remain in terms of how fast or even whether these efforts can alleviate the export restrictions.

### 5.4 Competition from LNG Substitutes

Other energy sources such as renewable energy, nuclear, hydro, coal and oil are all substitutes of LNG. Changes in their relative prices, technological development and social acceptance can have significant impact on the competitiveness of LNG both in the short run and long run, and thus pose uncertainties on the global demand of LNG cargos. For instance, the recent cheap American coal due to the shale gas revolution has shown a crowd-out effect on the European LNG market, even though the latter shows superior environmental benefits to the former. However, these substitutions are complicated, and discussion of all alternative energy sources is beyond the scope of this report[13]. Here, we will focus on two alternative sources of natural gas that can compete directly with LNG: pipeline gas and domestic production.

#### *5.4.1 Pipeline Gas*

Pipeline as a transportation option for natural gas predates LNG vessels. It is cost competitive for distances below 2500 km and for inland destinations. However, it has many severe geological and political constraints, especially in the case of cross-border trade. The gas pipelines connecting Russia and its customers in Europe and the Far East can be identified as the sources of most uncertainty to the future of regional and global LNG trade. Ongoing tension between Ukraine and Russia are again testing the brittle mutual confidence between Russia and its Western counterparts. This is not the first time that such events put the Russian gas supply to Western European nations at risk, and the mutual dependency of these two parties on energy trade sets certain invisible constraints that prevent them from behaving too radically, but the uncertainty lies in how long this delicate balance can be further maintained.

Aside from maneuvers in political and economic spheres, both sides are trying to change the status quo of the gas supply. The cold weather and abruption of natural gas supply in 2009 have reminded Europeans of how unreliable the pipeline gas from the East can be in times of geopolitical tension. As a result, the European Union is pushing for additional options, such as the Nabucco pipeline. Russia seeks to diversify its western supply route away from Ukraine by constructing a new pipeline called "South Stream". The capacity will be 2.2 Tcf (equivalent to 46 million tons of LNG) once fully online, and the construction is underway. However, on 17

[12] Mozambique is revising the Petroleum law, may change the royalty and tax regimes.

[13] See *MIT Joint Program Energy and Climate Outlook* for a long-term view of future energy development (MIT Joint Program, 2014).

April 2014, the European Parliament adopted a resolution opposing this gas pipeline as a sanction against Russian interventions in Ukraine, which poses new uncertainties on the project. Whether the supply will be interrupted again, and to what extent the European Union will lessen its reliance on Russian pipeline gas, are still up in the air. These uncertainties are being closely followed by LNG players in the European market, but events in this region may have equally important implications for the Asian LNG market.

A recently-concluded deal between Russia and China to supply China with 38 billion cubic meters (equivalent to 28 million tons of LNG) per year by 2019 can potentially be expanded, which can substantially reduce LNG demand from China. This may also affect other East Asian markets, as Eastern Siberia may grow into a gas hub that also provides gas to Japan and South Korea. Moreover, the massive amount of gas supply and the existence of a hub price will drive the emergence of regional prices in Asia and Europe (not considering the transport netback), further weakening the necessity for oil-indexed LNG contracts.

### *5.4.2 Domestic Gas Production*

New gas resources, such as shale gas, coal bed methane and deep sea gas fields are considered opportunities by many LNG exporting nations, as they can be sources of LNG feedstock. However, these resources can also lessen global LNG demand if significant domestic production materializes in current importers, similar to what happened in the US market. As can be seen in the table below, shale gas is more evenly distributed around the world, with much of it located in regions without much conventional gas resource. A 2013 EIA report (EIA, 2013) estimates that China's technically recoverable resources are 67% higher than the US unconventional gas resources (see **Table 4**). There are many obstacles for China's shale gas development, but if they are successfully overcome, China may become a net natural gas exporter by mid-century (Paltsev *et al.*, 2013b).

**Table 4.** Estimated technically recoverable shale gas resources, ranked by EIA estimate. Source: Energy Information Administration (2013).

| | | Resource Estimates (Tcf) | |
|---|---|---|---|
| **Rank** | **Country** | **EIA** | **ARI** |
| 1 | China | 1115 | |
| 2 | Argentina | 802 | |
| 3 | Algeria | 707 | |
| 4 | U.S. | 665 | 1161 |
| 5 | Canada | 573 | |
| 6 | Mexico | 545 | |
| 7 | Australia | 437 | |
| 8 | South Africa | 390 | |
| 9 | Russia | 285 | |
| 10 | Brazil | 245 | |
| | **World Total** | **7299** | **7795** |

According to EIA's report, unconventional gas production could reach 1300 billion cubic meters by 2035, accounting for more than one quarter of overall gas production—much higher than the 8% figure from 2011 (EIA, 2013). Much of the new growth may come from current importers such as China, Argentina and European nations.

However, the shale gas revolution in the US is not readily repeatable in other regions, as technical, social and political difficulties limit the pace at which other nations can develop their unconventional gas production capacities. The challenges in China include deeper, scattered and more complex reservoirs, lack of pipeline infrastructure to transport gas to demand centers and lack of water in many of the potential production areas. A general lack of risk-taking investors and entrepreneurs—considered as a major factor leading to the shale gas revolution in the US—further differentiates China's industry landscape. However, as previously discussed, the gradual liberalization of the energy market and increasing domestic price will eventually incentivize more private investment and thus increase domestic production in the long run. In Argentina, the biggest hurdle is a shortage of institutional capability to set and implement domestic production plans. Without significant foreign investment and efficient domestic management, Argentina has turned from a former regional natural gas exporter into a net importer of LNG in recent years. Whether shale gas can renovate its energy productivity depends on meaningful reform in political and economic arenas. Finally, in some European nations, the concern over potential environmental destruction and harassment to the local community has slowed—if not stopped—the development of unconventional gas industry. In conclusion, it remains to be seen whether and when barriers and difficulties in natural gas net importing regions can be overcome.

### 5.5 Implications for New Projects

As mentioned above, there will be a substantial increase in global LNG export capacity in the next five to ten years due to a completion of new projects, mostly in Australia and North America. Australia's near-term additions are at the same level that Qatar has added in 2008–2011, which made it the world largest LNG supplier (Jensen, 2014a). There are several new natural gas discoveries, whose developers consider building new LNG exports facilities. These are mostly located in East Africa (Mozambique and Tanzania) and East Mediterranean (Israel and Cyprus). As LNG projects have a long lifetime, developers must assess long-term prospects for international natural gas prices. With a certain additional supply and uncertain additional demand, these potential projects might be entering the LNG market in the new conditions, where Asian natural gas prices might not be at a high premium as they were in 2011–2014. European natural gas demand is even more uncertain due to recent geopolitical developments, but total natural gas demand in Europe is projected to stay roughly constant in the long term (Paltsev, 2014). Recent tensions over Ukraine may force Europe to actively seek alternative suppliers, creating some opportunities for additional LNG.

Projects with relatively inexpensive feed gas and close proximity to potential buyers have an advantage. Initial estimates of the amount of gas and its costs make the East African projects attractive. East Mediterranean gas has potential, but the lower than expected volumes discovered so far and longer distances to the Asian markets makes it a development area which most likely will serve the local markets with some potential for exports to Europe.

The US projects for LNG exports are very attractive at the current difference between the US and Asian prices. Some projects in the Gulf of Mexico are already well under construction. New projects face the same uncertainty over additional demand in Asia and the resulting price wedge between the North American and Asian prices. With a potential re-start of nuclear generation in Japan and slight increases in demand in South Korea, longer-term natural gas price dynamics will be affected by natural gas developments in China and India. China's shale gas production is yet to materialize, and competition over pipeline gas from Russia and Central Asia is currently limited, but these regions have the potential to substantially expand their supplies to China. A recent natural gas price reform in China and problems with mostly coal-driven air pollution might open additional possibilities for natural gas there, but these developments are expected to be highly affected by future government policies in China, which are harder to assess. India's natural gas market is still in its infancy due to infrastructure issues, and will most likely take longer to fully develop. All of these considerations make new capital-intensive LNG projects a risky investment, but with potentially high returns.

## 6. CONCLUSIONS

These natural gas perspectives largely depend on demand choices, on the availability and evolution of alternative fuels (e.g. renewable energies), and most importantly on political decisions framing the economic behavior. The introduction of liquefied natural gas (LNG) as an option for international trade has created a market for natural gas where global prices may eventually be differentiated by the transportation costs between world regions. While LNG's trade share in 2013 was only about 30 percent of the total global trade in natural gas, use of LNG is on the rise and numerous projects are in planning or construction stages. The market is currently led by Qatar and Indonesia, but new suppliers from Australia, USA and Canada are expected. Considering LNG projects that are planned, proposed, or under construction, we provide an analysis of LNG prospects for the next decade. Trade volumes are projected to increase from about 240 Mt LNG in 2013 to about 340–360 Mt LNG in 2021. Despite potential challenges from weaker demand in Asia, long-term projections show that LNG trade is bound to show substantial growth, partially due to geopolitical tensions that might increase LNG flows to Europe.

Many projects that will come online soon were developed based on the high Asian premium for natural gas price. For several years, US prices were in the range of $4–5/mmbtu, European prices were in the range of $8–11/mmbtu, and Asian prices in the range of $14–16/mmbtu. Considering combined liquefaction and transportation costs in the order of $4–6/mmbtu, exports to Asian markets were a very attractive option. However, new LNG supplies from Australia and North America and slower demand increases in Asia may erode that high premium for Asian gas, which will have implications for new potential LNG projects that will now have to compete in different market conditions. Price differences are expected to narrow, and opportunities for arbitrage to diminish. At the same time, more trade will have to be executed on spot markets, which will further erode trade based on long-term contracts.

Will LNG enter its golden age? Although 2014 marked the 50th anniversary of commercial LNG trade, the industry has substantial unexploited potential both in terms of reducing capital requirements (especially for liquefaction projects), expanding new technology frontiers like floating LNG (Jensen, 2014b), serving new markets, and establishing new pricing schemes that better reflect the fundamentals of supply and demand. As natural gas use is projected to increase substantially in the long term (MIT Joint Program, 2014), the LNG industry is in a great position for further expansion.

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## APPENDIX A. CONVERSION FACTORS

**Table A1.** Unit conversion. Source: BP (2014).

| | | bcm NG | bcf NG | mtoe | mt LNG | trillion btu | mboe |
|---|---|---|---|---|---|---|---|
| *1 billion cubic meters NG* | **bcm NG** | – | 35.3 | 0.9 | 0.74 | 35.7 | 6.6 |
| *1 billion cubic feet NG* | **bcf NG** | 0.028 | – | 0.025 | 0.021 | 1.01 | 0.19 |
| *1 million tons oil equivalent* | **mtoe** | 1.11 | 39.2 | – | 0.82 | 39.7 | 7.33 |
| *1 million tons LNG* | **mt LNG** | 1.36 | 48 | 1.22 | – | 48.6 | 8.97 |
| *1 trillion British thermal units* | **trillion btu** | 0.028 | 0.99 | 0.025 | 0.021 | – | 0.18 |
| *1 million barrels oil equivalent* | **mboe** | 0.15 | 5.35 | 0.14 | 0.11 | 5.41 | – |

# APPENDIX B. EXISTING LNG PLANTS

**Table B1.** Operational liquefaction plants. Source: IGU World LNG Report, PFC Energy Global LNG Service, Global LNG Information (2013)[14].

| Region | Country | Name | Started | Capacity *Mt* | Company |
|---|---|---|---|---|---|
| USA | United States | Kenai | 1969 | 1.5 | ConocoPhillips |
| AFR | Libya | Marsa El Brega | 1970 | 3.0 | LNOC, Shell |
| REA | Brunei | Brunei LNG T1-5 | 1972 | 7.2 | BLNG, Shell, Mitsubishi |
| AFR | Algeria | Skikda -GL1K (T1-4) | 1972 | 1.0 | Sonatrach |
| ASI | Indonesia | Bontang LNG T1-2 | 1977 | 5.4 | Pertamina |
| MES | United Arab Emirates | ADGAS LNG T1-2 | 1977 | 2.6 | ADNOC, Mitsui, BP, TOTAL |
| ASI | Indonesia | Arun LNG T1 | 1978 | 1.65 | Pertamina |
| AFR | Algeria | Arzew -GL1Z (T1-6) | 1978 | 6.6 | Sonatrach |
| AFR | Algeria | Arzew -GL2Z (T1-6) | 1981 | 8.2 | Sonatrach |
| AFR | Algeria | Skikda -GL2K (T5-6) | 1981 | 2.2 | Sonatrach |
| ASI | Indonesia | Bontang LNG T3-4 | 1983 | 5.4 | Pertamina |
| ASI | Malaysia | MLNG Satu (T1-3) | 1983 | 8.1 | PETRONAS, Mitsubishi, Sarawak State Gvt. |
| ASI | Indonesia | Arun LNG T6 | 1986 | 2.5 | Pertamina |
| ANZ | Australia | North West Shelf T1 | 1989 | 2.5 | BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui |
| ANZ | Australia | North West Shelf T2 | 1989 | 2.5 | BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui |
| ASI | Indonesia | Bontang LNG T5 | 1989 | 2.9 | Pertamina |
| ANZ | Australia | North West Shelf T3 | 1992 | 2.5 | BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui |
| ASI | Indonesia | Bontang LNG T6 | 1994 | 2.9 | Pertamina |
| MES | United Arab Emirates | ADGAS LNG T3 | 1994 | 3.2 | ADNOC, Mitsui, BP, TOTAL |
| ASI | Malaysia | MLNG Dua (T1-3) | 1995 | 7.8 | PETRONAS, Mitsubishi, Sarawak State Gvt. |
| MES | Qatar | Qatargas I (T1) | 1997 | 3.2 | Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui |
| MES | Qatar | Qatargas I (T2) | 1997 | 3.2 | Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui |
| ASI | Indonesia | Bontang LNG T7 | 1998 | 2.7 | Pertamina |
| MES | Qatar | Qatargas I (T3) | 1998 | 3.1 | Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui |
| AFR | Nigeria | NLNG T1 | 1999 | 3.3 | NNPC, Shell, TOTAL, Eni |
| ASI | Indonesia | Bontang LNG T8 | 1999 | 3.0 | Pertamina |
| LAM | Trinidad & Tobago | ALNG T1 | 1999 | 3.3 | BP, BG, Shell |
| MES | Qatar | RasGas I (T1) | 1999 | 3.3 | Qatar Petroleum, ExxonMobil,Kogas, Itochu, LNG Japan |
| AFR | Nigeria | NLNG T2 | 2000 | 3.3 | NNPC, Shell, TOTAL, Eni |
| MES | Oman | Oman LNG T1 | 2000 | 3.55 | Petroleum Development Oman (PDO), Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu |
| MES | Oman | Oman LNG T2 | 2000 | 3.55 | Petroleum Development Oman (PDO), Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu |
| MES | Qatar | RasGas I (T2) | 2000 | 3.3 | Qatar Petroleum, ExxonMobil,Kogas, Itochu, LNG Japan |
| AFR | Nigeria | NLNG T3 | 2002 | 3.0 | NNPC, Shell, TOTAL, Eni |
| LAM | Trinidad & Tobago | ALNG T2 | 2002 | 3.5 | BP, BG, Shell*, CIC, NGC Trinidad |
| ASI | Malaysia | MLNG Tiga (T1-2) | 2003 | 6.8 | PETRONAS, Mitsubishi, Sarawak State Gvt. |

[14] Conflicting data resolved through online search of company website

| Region | Country | Name | Started | Capacity *Mt* | Company |
|---|---|---|---|---|---|
| LAM | Trinidad & Tobago | ALNG T3 | 2003 | 3.5 | BP, BG, Shell |
| ANZ | Australia | North West Shelf T4 | 2004 | 4.4 | BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui |
| MES | Qatar | RasGas I I(T1) | 2004 | 4.7 | Qatar Petroleum, ExxonMobil |
| AFR | Egypt | ELNG T1 | 2005 | 3.6 | PETRONAS, EGAS, EGPC, GDF SUEZ |
| AFR | Egypt | ELNG T2 | 2005 | 3.6 | PETRONAS, EGAS, EGPC, GDF SUEZ |
| AFR | Egypt | ELNG T2 | 2005 | 5.0 | Gas Natural Fenosa, Eni, EGPC, EGAS |
| MES | Qatar | RasGas I I(T2) | 2005 | 4.7 | Qatar Petroleum, ExxonMobil |
| AFR | Nigeria | NLNG T4 | 2006 | 4.1 | NNPC, Shell, TOTAL, Eni |
| AFR | Nigeria | NLNG T5 | 2006 | 4.1 | NNPC, Shell, TOTAL, Eni |
| ANZ | Australia | Darwin LNG T1 | 2006 | 3.6 | ConocoPhillips, Santos, INPEX, Eni, TEPCO, Tokyo Gas |
| LAM | Trinidad & Tobago | ALNG T4 | 2006 | 5.2 | BP, BG, Shell, NGC Trinidad |
| MES | Oman | Qalhat LNG | 2006 | 3.7 | Omani Govt, Petroleum Development Oman (PDO), Shell, Mitsubishi, Gas Natural Fenosa, Eni, Itochu, Osaka Gas, TOTAL, etc. |
| EUR | Norway | Snøhvit LNG T1 | 2007 | 4.2 | tatoil, Petoro, TOTAL, GDF SUEZ |
| AFR | Equatorial Guinea | EG LNG T1 | 2007 | 3.7 | Marathon, Sonagas, Mitsui, Marubeni |
| MES | Qatar | RasGas I I(T3) | 2007 | 4.7 | Qatar Petroleum, ExxonMobil |
| AFR | Nigeria | NLNG T6 | 2008 | 4.1 | NNPC, Shell, TOTAL, Eni |
| ANZ | Australia | North West Shelf T5 | 2008 | 4.4 | BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui |
| ASI | Indonesia | Tangguh LNG T1 | 2009 | 3.8 | BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan,Talisman Energy, Kanematsu, Mitsui |
| ASI | Indonesia | Tangguh LNG T2 | 2009 | 3.8 | BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan,Talisman Energy, Kanematsu, Mitsui |
| RUS | Russia | Sakhalin 2 (T1) | 2009 | 4.8 | Gazprom, Shell, Mitsui, Mitsubishi |
| RUS | Russia | Sakhalin 2 (T2) | 2009 | 4.8 | Gazprom, Shell, Mitsui, Mitsubishi |
| MES | Qatar | Qatargas II (T1) | 2009 | 7.8 | Qatar Petroleum, ExxonMobil |
| MES | Qatar | Qatargas II (T2) | 2009 | 7.8 | Qatar Petroleum, ExxonMobil |
| MES | Qatar | RasGas III(T1) | 2009 | 7.8 | Qatar Petroleum, ExxonMobil |
| MES | Yemen | Yemen LNG T1 | 2009 | 3.35 | TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai |
| ASI | Malaysia | MLNG Dua Debottleneck | 2010 | 1.2 | PETRONAS, Shell, Mitsubishi, Sarawak State Gvt. |
| EUR | Norway | Skangass LNG | 2010 | 0.3 | Skangass |
| MES | Qatar | Qatargas III | 2010 | 7.8 | Qatar Petroleum, ExxonMobil |
| MES | Qatar | RasGas III(T2) | 2010 | 7.8 | Qatar Petroleum, ExxonMobil |
| MES | Yemen | Yemen LNG T2 | 2010 | 3.35 | TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai |
| LAM | Peru | Peru LNG | 2010 | 4.45 | Hunt Oil, Shell, SK Corp, Marubeni |
| MES | Qatar | Qatargas IV | 2011 | 7.8 | Qatar Petroleum, Shell |
| ANZ | Australia | Pluto T1 | 2012 | 4.3 | Woodside, Kansai Electric, Tokyo Gas |
| REA | Brunei | BLNG (Lumut II) | 2013 | 4.0 | BLNG, Shell, Mitsubishi |
| AFR | Angola | Angola LNG | 2013 | 5.2 | Chevron, Sonangol, BP, Eni, TOTAL |

## APPENDIX C. SALES, PURCHASE AGREEMENTS AND PRICING

Sales and purchase agreements (SPAs) are signed between suppliers and receiving terminals to assign rights and obligations between the two parties. The most critical part of SPA is the pricing formula, which typically uses the following formation:

$$P = C + \beta X$$

where $P$ is the price (\$/mmbtu), $C$ is the base price, $\beta$ is the gradient or price slope and $X$ is the targeted indexation. The price could either be delivered ex ship (DES) or free on board (FOB), depending on who is responsible for the shipping of the gas. $C$ and $\beta$ are negotiated between the two parties. For $X$, there are three major pricing systems in LNG SPAs:

- **Oil-Indexed Contracts.** Linked to the crude oil price reference benchmark (e.g. Japan Crude Cocktail) and primarily used in the Eastern Asian market, including Japan, South Korea, China and Taiwan. A long-term contract can last for 15 to 25 years.
- **Take-or-Pay Contracts.** Linked to a mixed price based on multiple energy sources and primarily used in Continental Europe. Components vary from contract to contract (2b1 Consulting, 2012) and may include indexes such as Brent crude price, heavy fuel oil price, light fuel oil price, gas oil price, coal price, electricity price and natural gas price.
- **Market-Indexed Contracts.** Linked to the gas hub index; used by the US and UK.

Indexation, base price and gradient can have significant effects on the profitability and risks of a project. For instance, a market-indexed contract is considered riskier for the supplier than an oil-indexed contract, due to the volatility and lower price of pipeline gas and the expected high oil price. On average, one million BTUs of gas have about 1/6 of the energy content of a barrel of oil (i.e., the 6-to-1 heat-equivalent parity), and an oil-indexed contract would adopt a price slope close to the heat-equivalent parity—usually around 14%–15% (Ernst & Young, 2012). The constant $C$ is typically about US\$0.60–0.90 (Lucas, 2013), and the current crude oil price is around US\$100/barrel, which translates into a LNG price of US\$14.60–15.90/mmbtu. On the other hand, the Henry Hub price of natural gas is expected to rise to US\$5–6/mmbtu (in early 2014); accounting for other costs and required rate of return, the break-even FOB price is in the range of US\$9–11/mmbtu (Wood, 2012).

To shield against market volatility, some contracts will use multiple price slopes at different reference price levels. For instance, buyers in an oil-indexed contract would prefer a flatter slope at high oil prices, while sellers prefer a flatter slope at low oil prices; thus, a mechanism may be used that provides protection on both ends of the price spectrum, usually referred to as an "S-curve" contract (see Figure 6).

Other factors in the SPA can also influence perceived risk. If a counter party has low credibility or financial strength, their willingness and ability to honor the contracts must be considered, as these factors may increase perceived risk. Terms allowing renegotiation after a significant market change or predetermined period of time can lower perceived risk, but may also reduce returns. Destination flexibility (combined with profit sharing of the subsequent arbitrage) can also lower the perceived project risks for the supplier by providing extra revenues when there is market disequilibrium.

## APPENDIX D. LNG PLANTS, PLANNING AND CONSTRUCTION

**Table D1.** LNG plants under construction. Source: IGU World LNG Report, PFC Energy Global LNG Service, Global LNG Information (2013).

| Region | Country | Name | Start Year *Planned* | Capacity *Mt* | Company |
|---|---|---|---|---|---|
| ANZ | Australia | QC LNG | 2014 | 8.5 | BG, CNOOC, Tokyo Gas |
| AFR | Algeria | Arzew -GL3Z (Gassi Touil) | 2014 | 4.7 | Sonatrach |
| LAM | Colombia | Pacific Rubiales | 2014 | 0.5 | Excelerate Energy, Pacific Rubiales Energy |
| ASI | Indonesia | Sengkang LNG | 2014 | 1.0 | Mitsubishi Corp |
| ASI | Indonesia | Sulawesi LNG (Donggi Senoro) | 2014 | 7.7 | Mitsubishi, Kogas, Pertamina, and Medco |
| ASI | Malaysia | Bintulu mini expansion | 2014 | 0.67 | Petronas |
| ANZ | Papua New Guinea | PNG LNG | 2014 | 6.9 | ExxonMobil, Oil Search, NPCP, Santos, JXNOFE, PNG |
| ANZ | Australia | Gorgon LNG T1 & T2 | 2015 | 10.4 | Chevron, ExxonMobil, Shell, Japanese gas & electric utilities |
| ANZ | Australia | AP LNG (Origin) T2 | 2015 | 4.5 | Origin Energy, ConocoPhillips, Sinopec |
| ANZ | Australia | Gladstone LNG | 2015 | 3.9 | Santos, Petronas |
| ASI | Malaysia | PETRONAS T9 | 2015 | 3.9 | Petronas |
| USA | United States | Sabine Pass LNG T1 | 2015 | 4.5 | Cheniere Energy Partners LP |
| ANZ | Australia | Gorgon LNG T3 | 2016 | 5.2 | Chevron, ExxonMobil, Shell, Japanese gas & electric utilities |
| ANZ | Australia | AP LNG (Origin) | 2016 | 4.5 | Origin Energy, ConocoPhillips, Sinopec |
| ANZ | Australia | Gladstone LNG | 2016 | 3.9 | Santos, Petronas |
| ANZ | Australia | Wheatstone | 2016 | 8.9 | Chevron, Apache, KUFPEC (Kuwait), Shell, Japanese gas & electric utilities |
| USA | United States | Sabine Pass LNG T2 & T3 | 2016 | 9.0 | Cheniere Energy Partners LP |
| ANZ | Australia | Ichthys LNG | 2017 | 8.4 | INPEX, Total, Japanese gas & electric utilities |
| ANZ | Australia | Prelude FLNG | 2017 | 3.6 | Shell, Inpex, Kogas, CPC |
| USA | United States | Sabine Pass LNG T4 | 2017 | 4.5 | Cheniere Energy Partners LP |

**Table D2.** LNG plants in planning stages. Source: Global LNG Information, Macquarie Research, and online search (2013).

| Region | Country | Name | Start Year *Planned* | Capacity *Mt* | Company |
|---|---|---|---|---|---|
| AFR | Angola | Angola LNG T2 | 2021 | 5.0 | Chevron, Sonangol, BP, Eni, TOTAL |
| ANZ | Australia | Fisherman's L. | 2017 | 3.0 | LNG Ltd, CNPC subsidiary |
| ANZ | Australia | QCLNG Train 3 | 2017 | 4.3 | BG Group |
| ANZ | Australia | Sunrise LNG | 2017 | 11.0 | Woodside, ConocoPhillips, Shell, Osaka Gas |
| ANZ | Australia | Gorgon LNG T4 | 2018 | 5.0 | Chevron, ExxonMobil , Shell, Japanese gas & electric utilities |
| CAN | Canada | BC LNG Douglas Channel | 2016 | 1.9 | Tatham Family |
| CAN | Canada | Kitimat LNG | 2019 | 5.32 | Chevron, Apache |
| CAN | Canada | Shell LNG Canada | 2019 | 24.3 | Shell, PCL, Kogas, Mitsubishi, PetroChina |
| CAN | Canada | Goldboro | 2019 | 6.0 | Pieridae Energy Canada |
| CAN | Canada | Pacific Northwest LNG | 2020 | 7.4 | PETRONAS, Progress Energy |
| CAN | Canada | BC LNG | 2020 | 21.6 | British Gas Group |
| AFR | Equatorial Guinea | EG LNG T2 | 2016 | 4.4 | EGLNG |
| ASI | Indonesia | Abadi FLNG | 2016 | 2.5 | INPEX Masela, Shell, PTEMP |
| ASI | Indonesia | Tangguh T3 | 2019 | 3.8 | BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan, Talisman Energy, Kanematsu, Mitsui |
| MES | Iraq | Shell Basra FLNG T1, T2 | 2022 | 9.0 | Shell and Iraq Gov |
| ASI | Malaysia | PFLNG1 (Sarawak) | 2015 | 1.2 | Petronas |
| ASI | Malaysia | Bintulu Train 9 | 2016 | 3.6 | Petronas |
| ASI | Malaysia | PFLNG1 (Sabah) | 2016 | 1.5 | Petronas |
| AFR | Mozambique | Mozambique LNG 1,2 | 2018 | 9.0 | Eni |
| AFR | Nigeria | Olokola | 2015 | 22.0 | NNPC, BG Group |
| AFR | Nigeria | NLNG Train 7 & 8 | 2015 | 8.4 | NLNG |
| AFR | Nigeria | Brass LNG | 2016 | 10.0 | ConocoPhillips |
| ANZ | Papua New Guinea | PNG LNG T3 | 2017 | 3.3 | ExxonMobil, Oil Search, NPCP, Santos, JXNOFE, PNG |
| RUS | Russia | Yamal LNG | 2016 | 16.5 | Yamal |
| RUS | Russia | Shtokman (Ph 1) | 2020 | 7.5 | Giprospetsgas JSC (Gazprom JSC) |
| RUS | Russia | Sakhalin 2 T3 | 2019 | 5.0 | Sakhalin Energy |
| RUS | Russia | Vladivostok | 2020 | 10.0 | Gazprom |
| RUS | Russia | Shtokman (other) | 2020 | 12.5 | Giprospetsgas JSC (Gazprom JSC) |
| LAM | Trinidad & Tobago | Atlantic LNG T5 | 2015 | 5.2 | BP, BG, Shell |
| USA | United States | Freeport LNG Expansion | 2015 | 13.6 | Freeport LNG |
| USA | United States | Dominion Cove Point LNG, LP | 2017 | 13.5 | Dominion Resources |
| USA | United States | Lake Charles | 2018 | 15.2 | Trunkline LNG |

**Table D3.** Speculative LNG projects. Source: Macquarie Research and online search (2013).

| Region | Country | Name | Start Year *Planned* | Capacity *Mt* | Company |
|---|---|---|---|---|---|
| ANZ | Australia | Darwin LNG T2 | 2016 | 5.0 | Conoco |
| ANZ | Australia | Cash Maple LNG | 2017 | 1.0 | PTTEP |
| ANZ | Australia | Arrow | 2018 | 8.0 | Shell, PetroChina |
| ANZ | Australia | Bonaparte | 2018 | 2.1 | GDF Suez, Santos |
| ANZ | Australia | Pilbara LNG | 2018 | 6.0 | - |
| ANZ | Australia | Scarborough | 2020 | 5.2 | BHP and ExxonMobil |
| ANZ | Australia | Browse | 2020 | 12.0 | Woodside, Shell, BP, PetroChina, Mitsui, Mitsubishi |
| ANZ | Australia | Wheatstone T3 | 2020 | 4.5 | Chevron, Apache, KUFPEC (Kuwait), Shell, Japanese gas & electric utilities |
| ANZ | Australia | Tassie Shoal | 2021 | 3.0 | - |
| BRA | Brazil | Santos FLNG | 2017 | 3.5 | - |
| CAN | Canada | Squamish | 2017 | 2.0 | Woodfibre LNG Export |
| CAN | Canada | Melford | 2021 | 14.0 | H-Energy |
| CAN | Canada | Aurora LNG | 2021 | 5.0 | CNOOC Nexon |
| CAN | Canada | ExxonMobil | 2021 | 10.0 | ExxonMobil |
| AFR | Mozambique | Mozambique LNG 3,4 | 2021 | 9.0 | - |
| AFR | Mozambique | Mozambique LNG 5,6 | 2024 | 9.0 | - |
| AFR | Mozambique | Mozambique LNG 7,8 | 2027 | 9.0 | - |
| AFR | Mozambique | Mozambique LNG 9,10 | 2030 | 9.0 | - |
| AFR | Nigeria | Progress FLNG | 2017 | 10.0 | - |
| EUR | Norway | Snohvit T2 | 2018 | 4.2 | - |
| ANZ | Papua New Guinea | Gulf LNG Interoil | 2022 | 3.8 | Interoil |
| AFR | Tanzania | Tanzania LNG | 2019 | 8.0 | - |

**Table D4.** Proposed LNG projects in the US. Source: FERC (2014).

| **Name** | **Approved Capacity** | **2014 Status** | | |
|---|---|---|---|---|
| | *Mt* | *construction* | *proposed* | *potential* |
| Sabine Pass | 21.0 | ■ | | |
| Cameron | 12.9 | | ■ | |
| Freeport | 13.7 | | ■ | |
| Cove Point | 6.2 | | ■ | |
| Corpus Christi | 16.0 | | ■ | |
| Jordan Cove | 6.8 | | ■ | |
| Trunkline | 16.7 | | ■ | |
| Oregon LNG | 9.5 | | ■ | |
| Excelerate | 10.5 | | ■ | |
| Southern | 2.7 | | ■ | |
| Sabine Pass | 10.6 | | ■ | |
| Magnolia | 8.1 | | ■ | |
| CE FLNG | 8.1 | | ■ | |
| Golden Pass | 16.0 | | ■ | |
| Gulf LNG | 11.4 | | ■ | |
| Loiusiana LNG | 2.3 | | ■ | |
| Downeast | 3.4 | | ■ | |
| Venture Global | 10.6 | | ■ | |
| Gulf Coast LNG | 21.3 | | | ■ |
| Waller LNG | 1.2 | | | ■ |
| Pangea LNG | 8.3 | | | ■ |
| Gasfin Development | 1.5 | | | ■ |
| Eos&Barca | 24.3 | | | ■ |
| Freeport-McMoRan | 24.5 | | | ■ |
| Annova | 7.1 | | | ■ |
| Delfin | 13.7 | | | ■ |
| Texas LNG | 2.1 | | | ■ |
| SCT&E LNG | 12.2 | | | ■ |
| WesPac | 1.5 | | | ■ |
| Next Decade | 5.9 | | | ■ |

* Status and capacities are from the US Federal Energy Regulatory Commission (FERC) at: http://www.ferc.gov/industries/gas/indus-act/lng.asp. Requested capacity may differ from the actual capacity constructed. For example, while the approved capacity at Sabine Pass is 21 Mt, Cheniere is only building four LNG trains with 4.5 Mt capacity each, which totals 18 Mt.

# APPENDIX E. REGIONAL AGGREGATION

**Table E1.** Region specifications.

| | |
|---|---|
| USA | USA |
| CAN | Canada |
| MEX | Mexico |
| BRA | Brazil |
| LAM | Rest of Americas |
| EUR | Europe |
| RUS | Russia |
| ROE | Rest of Europe and Central Asia |
| CHN | China |
| IND | India |
| JPN | Japan |
| ASI | Dynamic Asia |
| REA | Rest of East Asia |
| ANZ | Australia and Oceania |
| MES | Middle East |
| AFR | Africa |

Note: for a detailed composition of the regions, see MIT Joint Program (2014).

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