

# Global LNG

Will new demand and new supply mean new pricing?





# Introduction and su

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# Summary

With the start-up of the world's first commercial-scale liquefied natural gas (LNG) plant at Arzew in Algeria in 1964, the modern global LNG industry is approaching its 50th birthday in 2014.<sup>1</sup> A massive amount of new LNG capacity has been proposed – as much as 350 million (metric) tonnes per year (mtpa) – which, if all were built, would more than double current capacity (of less than 300 mtpa) by 2025. Even with reasonably strong demand growth, this implies growing supply-side competition and upward pressures on development costs and downward pressures on natural gas prices. Nevertheless, the very positive longer-term outlook for natural gas is driving investment decisions, both in terms of buyers' willingness to sign long-term contracts and sellers' willingness to commit capital to develop the needed projects.

LNG demand growth is front-loaded, but in the wake of a capacity surge over the last few years, capacity growth is now back-loaded. We are seeing a post-Fukushima squeeze, as well as a slowdown in near-term

capacity additions, pointing to relatively tight markets over the next few years. LNG development costs have been rising at a torrid pace, and with LNG demand shifting to new, more price-sensitive customers just as the supply side battles with rising costs and increasing competition, sellers must adapt.

The supply/demand magnitudes and dynamics aside, the biggest potential impacts are on LNG pricing: namely, will oil-price linkages continue to dominate global LNG contract pricing, will there be room for spot gas price linkages, and will divergent regional gas prices show signs of convergence?

Going forward over the medium to longer term, there will most likely be a gradual but partial migration away from oil-linked pricing to more spot or hub-based pricing. LNG sellers are reluctantly facing the realities of pricing and are offering concessions in order to remain competitive. However, LNG pricing should not collapse, simply because the cost to supply is high and incentives to develop new capacity must be maintained. As analysts at Macquarie point out, LNG is a very expensive game, and prices – however they are formed – must reflect this reality.<sup>2</sup>

<sup>1</sup> Liquefaction of natural gas was first achieved in the laboratory during the 19th century, and numerous localized small-scale peak-shaving LNG facilities were put into use in the early 1900s. The first transport of LNG occurred in 1959 from Louisiana to the UK, leading to the British Gas Council's signing of a 15-year contract for import of LNG from a proposed LNG plant in Algeria. The beginning of the modern LNG age is generally seen as the opening of that Algerian plant. (Source: Deutsche Bank Markets Research, *Global LNG*, 17 September 2012)

<sup>2</sup> Macquarie Equity Research, *Global LNG Outlook*, 10 September 2012



# Global natural gas and LNG demand

## Historic and projected demand

Total global natural gas demand is estimated to have grown by about 2.7% per year since 2000; however, global LNG demand has risen by an estimated 7.6% per year over the same period, almost three times faster.<sup>1</sup> The strong LNG demand growth has been largely driven on a regional perspective by Asia, and from a broader perspective, underpinned by what analysts at J.P. Morgan termed “durable, investible and politically charged themes.”<sup>2</sup>

- ▶ National energy supply security – ensuring supply diversity and flexibility
- ▶ National energy infrastructure renewal to improve system resilience to supply/demand shocks, stimulate investment and reduce unemployment
- ▶ De-carbonization of economic growth as a social imperative, continuing the displacement of coal by natural gas
- ▶ Rising popular opposition to nuclear power generation

Global gas demand is expected to continue to grow strongly. In its most recent annual *World Energy Outlook*, the International Energy Agency (IEA) forecast a growing role for natural gas in the world’s energy mix, with the natural gas share growing from 21% in 2010 to 25% in 2035, with natural gas as the only fossil fuel whose share was growing. The IEA sees global natural gas demand growing at about 1.6% per year through 2035, more than twice the expected growth rate for oil.<sup>3</sup> Some other analysts/forecasters put gas’s growth rate even higher.

LNG demand growth is, however, expected to be even stronger, particularly through 2020. While a wide range of forecasts exists, a broad consensus of industry analysts/observers sees average annual growth of around 5% to 6% per year. After 2020, demand growth is expected to continue, albeit at a slightly slower pace (i.e., around 2% to 3% per year) as markets mature, demand shifts to more price-sensitive buyers, and some price subsidies

<sup>1</sup> Deutsche Bank Markets Research, *Global LNG: Gorgon & the Global LNG Monster*, 17 September 2012

<sup>2</sup> J.P. Morgan Cazenove Global Equity Research, *Global LNG*, 13 January 2012

<sup>3</sup> International Energy Agency, *World Energy Outlook 2012*, October 2012



are removed in non-OECD markets. Global LNG demand by 2030 could, however, be almost double that of the estimated 2012 level of about 250 million metric tonnes.

### Measures and conversion factors

Natural gas is most typically measured in volumetric terms, either in cubic feet (cf) or cubic meters (cm). For international consistency here, cubic meters are used with the following equivalence:

**1 cubic meter = 35.3 cubic feet**

LNG, however, is typically measured in millions (metric) tonnes per year (mtpa – sometimes abbreviated as mmtpa). For purposes of this report, the following conversions are used:

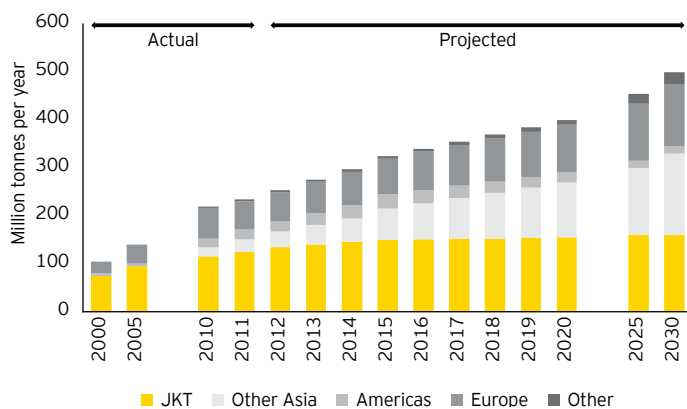
**1 million tonnes of LNG = 1.36 billion cubic meters (bcm) of natural gas, or about 48 billion cubic feet (bcf) of natural gas**

Japan, South Korea and Taiwan (collectively, JKT) have been and are expected to remain the backbone of the global LNG market. Accounting for more than half of total global LNG demand in 2012, JKT are characterized as heavily industrialized countries with limited domestic energy options – i.e., they are seen as the “premium” LNG markets. However, the newer and growing LNG demand centers – China, India, the Middle East, Europe and South America – tend to have more available competitive energy options, including coal and oil, as well as other sources of natural gas – either from domestic production or pipeline imports. As a result, these new markets will generally be less likely to willingly pay supply security premiums and will be more price-sensitive.

More than 30 countries have proposed plans to build or add LNG import/re-gasification capacity, with many of those countries new to the LNG market. By 2020, the number of countries with import capacity could double from the 25 countries at the end of 2011. Current global re-gasification capacity of almost 600 mtpa far exceeds current/projected supply or demand and yet could rise by as much as 200 mtpa by 2020.<sup>4</sup>

China and India are expected to be the biggest sources of additional LNG demand. The latest Five-Year Plan to “gasify” the Chinese economy calls for the gas share of the energy mix to rise from ~4% in 2010 to 8% by 2015, with a longer-term goal of a 10% share by 2020.<sup>5</sup> Beyond 2020, China’s potential gas demand is huge, considering that China’s coal market is seven times larger than the total global LNG market.<sup>6</sup> China has considerable development ambitions for its shale gas resources as well as for import pipeline expansions, but will still need significant volumes of imported LNG to meet demand. Importantly, with multiple supply options, China’s aggressive near-to-medium demand forecasts are seemingly well-covered by increasing domestic supply, increasing pipeline imports and signed LNG contracts.

Figure 1. Global LNG demand



Source: Ernst & Young assessments of data from multiple sources

4 J. P. Morgan Cazenove Global Equity Research, *Global LNG*, 13 January 2012  
 5 OilPrice.com, “China Turns to Natural Gas to Fuel their Economic Growth,” 19 June 2012  
 6 Deutsche Bank Markets Research, *Global LNG: Gorgon & the Global LNG Monster*, 17 September 2012

## Natural gas in China: fueling the dragon

Driven by government policy and strategy, Chinese natural gas demand could more than double between 2012 and 2020. Planned aggressive expansion of domestic gas production, particularly from shale gas development, will satisfy some of the demand increase, as will the expected import pipeline developments, but the expected imports of LNG that will be needed to balance demand will more than quadruple. Should shale development disappoint or pipeline expansions be delayed, LNG imports will increase even further.

**Table 1. Chinese natural gas supply/demand balance**

(bcm)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<b>Demand</b>	110	135	163	182	204	229	256	287	322	360	403
<b>Supply</b>											
<b>Domestic production</b>											
Conventional	92	100	117	119	129	138	144	147	151	155	159
Shale			1	2	5	6	10	20	30	45	68
Other	1	3	5	8	11	13	16	18	20	22	24
Subtotal	94	103	122	129	144	158	170	185	201	222	250
<b>Pipeline imports</b>											
Turkmen 1	4	14	21	25	30	30	30	30	30	30	30
Myanmar				3	8	12	12	12	12	12	12
Turkmen 2						0	6	15	30	30	30
Subtotal	4	14	21	28	38	42	48	57	72	72	72
<b>LNG imports to balance</b>	13	17	20	25	22	29	39	45	49	67	81
LNG imports (mtpa)	9	12	15	18	16	21	28	33	36	49	60
LNG contracted (mtpa)	9	12	15	18	22	26	32	37	37	37	37
Regas capacity* (mtpa)	12	16	21	28	41	45	54	61	65	67	70

\*Approved or proposed

Source: Deutsche Bank Markets Research, *Gorgon & the Global LNG Monster*, 17 September 2012

In particular, replicating the North American shale successes may be difficult. Chinese shale basins are generally smaller, deeper and more complex. They are also spread out across more than 150 separate basins and generally are distant from demand centers. And with limited existing infrastructure in many areas, as well as water supply issues, costs are expected to be substantially higher. Importantly, state regulation of gas prices may defer risk-taking by non-NOCs, and more broadly, China generally lacks the community of incentivized risk-taking independents that essentially pioneered the technological changes in horizontal drilling and hydraulic fracturing. This may effectively slow down the pace of China's shale evolution.

European LNG demand is expected to grow as local production, primarily from the North Sea, declines and total gas demand grows as a result of economic growth as well as environmental preferences and Kyoto Protocol commitments. Forecasting LNG supply and demand for Europe is made difficult, however, by the multiple domestic and regional supply options; multiple pipeline import sources (Russia, North Africa and Norway); and, most prominently, by the evolving price/volume strategies by the two main regional suppliers, Russia and Norway.

## Demand-side risks for LNG

The principal risks for LNG demand growth come from uncertainties around the global and regional economies and from increasing gas-on-gas competition. Global economic growth has been decelerating over the last few years, with the recovery from the global financial crisis of 2008/2009 relatively slow and uneven. The US recovery has been relatively anemic, while the Eurozone crisis has hobbled the European continent. The emerging markets, led by China, have seen their growth restrained by the knock-on effects of the problems in their main markets, the advanced economies. Conventional expectations are for the global economy to stabilize and begin to grow more strongly. However, downside risks remain relatively high, and with those risks, uncertainties around energy demand growth will continue.

Relatively new, “unconventional” supplies of natural gas – including shale gas, tight gas and coalbed methane (CBM – also known as coal seam gas or CSG) – could transform the world’s energy markets. While global gas reserves have been growing steadily for decades, over the last decade, the so-called unconventional gas revolution has roughly tripled the resource base that can be economically recovered. A decade ago, the world was estimated to have only 50 to 60 years’ worth of gas remaining; with the new unconventional supplies, the estimated resource life has risen to more than 200 years.<sup>7</sup> Of the world’s estimated remaining technically recoverable natural gas resources, unconventional gas accounts for more than 331 trillion cubic meters (tcm) out of 752 tcm in total, or about 44% of the total. Shale gas accounts for an estimated 63% of the world’s

technically recoverable unconventional gas resources, and the IEA estimates that unconventional gas will increase to about 25% of the world’s gas supply by 2035, as compared to about 8% today.<sup>8</sup> Generally, lower-cost unconventional gas is likely to capture some of the demand that would have otherwise gone to LNG.

Planned or proposed new/expanded gas pipelines from Russia, the Caspian and/or Central Asia into Europe or Asia (e.g., the Nabucco or South Stream pipelines into southern/central Europe, the Turkmenistan-Afghanistan-Pakistan-India [TAPI] pipeline, an Iran-Pakistan pipeline or the Russian Altai pipeline into China) could deteriorate potential LNG demand markets in Europe or Asia. Clearly, not all of these proposals will come to fruition, but at least one of the lines into southern/central Europe is likely to be built, and a Russia-China line is also quite likely, given the Russian strategic gas marketing shift eastward.



<sup>7</sup> *The Economist*, “Special Report: An Unconventional Bonanza,” 14 July 2012

<sup>8</sup> International Energy Agency (IEA), *Golden Rules for a Golden Age of Gas*, June 2012



# LNG supply

## LNG liquefaction capacity

Beginning with the first commercial-scale liquefaction plant at Arzew in Algeria in 1964, global liquefaction capacity grew slowly if not steadily, reaching about 100 mtpa in the early 1990s and about 140 mtpa by 2000. But between 2000 and 2012, liquefaction capacity more than doubled, driven primarily by the series of massive LNG developments in Qatar and the early Australian developments.<sup>1</sup>

Over the industry's last five decades, we have seen a progressive broadening of the LNG supply base, with three waves of suppliers. The first wave was dominated by Algeria, Malaysia and Indonesia, which still collectively accounted for more than 60% of total LNG capacity as recently as 10 years ago, but which are expected to drop to about 20% of total capacity by 2020. The second wave has been dominated by Qatar and Australia, which have been rising rapidly from about 20% of global LNG capacity in 2000 and are expected to account for about 50% of total global capacity by 2020.

A huge wave of Australian LNG projects are slated for the second half of this decade. In the three years from late 2009, Australian operators have sanctioned more than 60 mtpa of greenfield LNG projects – equivalent to about 25% of current global LNG demand. But the plethora of proposed but unsanctioned projects, are unlikely to proceed without secure off-take commitments. There are increasing development risks for operators, and even with oil indexation, operators cannot assume that oil price increases will outpace cost increases.

The third wave could come from as many as 25 other countries, many of which currently have little or no capacity, but by 2020, these countries could provide as much as 30% of the world's LNG capacity. Importantly, with the third wave, smaller operators are becoming increasingly involved with what used to be the exclusive domain of the major IOCs and NOCs. While there were 19 LNG exporting countries in 2012, many of the new potential suppliers have substantial resource bases and potentially generally lower costs. But the scale of investment required and the ongoing

<sup>1</sup> J.P. Morgan Cazenove Global Equity Research, *Global LNG*, 13 January 2012



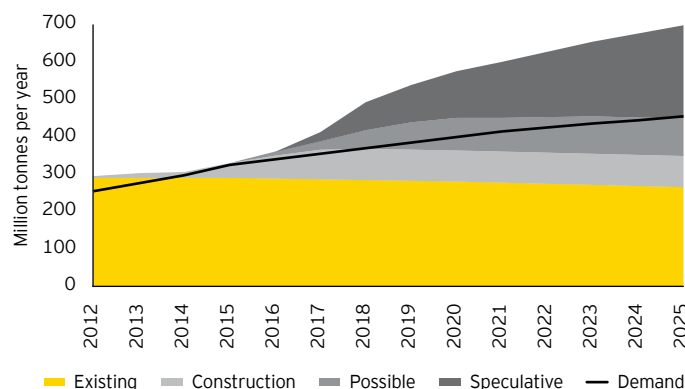


economic uncertainty may mean that many of these proposed projects are unlikely to move to final investment decision (FID).

LNG supply schemes in Iran, Venezuela (first suggested in the early 1970s) and Nigeria will struggle with geopolitical and financing issues. Proposed expansions in countries that are increasingly short of gas for domestic markets (e.g., Trinidad and Egypt) are also unlikely to proceed. The Eastern Mediterranean and East Africa are important new gas provinces and should support world-class LNG projects. Notably, the proposed US and Canadian LNG export projects will counter Australia's long-standing position as a politically stable major LNG supplier.

Looming tighter markets over the next three to five years or so suggests firming contract prices, at least until more new projects move to FID and production. By 2025, the global LNG market should have room for all of the projects that are currently seen as "possible." However, unless there is substantially higher growth in LNG demand, building a significant number of the "speculative" projects implies increasing supply-side competition.

**Figure 2. Global LNG capacity and demand**



Source: Ernst & Young assessments of data from multiple sources

## The new exporters – North America and East Africa

Current US law requires an export license from the US Department of Energy (DOE) in order to export LNG. In general, export of LNG to a nation that has a free trade agreement (FTA) with the US is considered in the public interest and is typically approved without modification or delay. The DOE has more latitude in modifying the terms and/or stipulating conditions in considering applications for export to non-FTA countries. At present, the US has FTAs with 19 countries, five of which currently import LNG (Canada, Mexico, the Dominican Republic, Chile and South Korea), with a sixth country, Singapore, set to have import capacity in 2013. Of the current FTA countries, only South Korea and potentially Singapore represent significant and economically viable markets.

As of late January 2013, 20 companies have submitted applications for US LNG export; 16 of these have been approved for FTA countries, but only one application, from Cheniere's Sabine Pass Liquefaction LLC, has received approval for export to non-FTA countries. The proposed projects are predominately located on the Gulf Coast, but also include proposed facilities on the East and West Coasts. Importantly, nine of the applications, including Cheniere's, would base exports from modified, existing LNG import facilities. These "brownfield" export projects would likely enjoy significant cost advantages from the existing in-place infrastructure (particularly utilities, storage and port facilities), in comparison with other "greenfield" projects, without such infrastructure already in place. Capital costs for US brownfield LNG projects are broadly estimated to be between US\$550 million and US\$650 million per mtpa of capacity, substantially less than typical greenfield projects.<sup>2</sup>

More than 200 mtpa of US LNG export capacity has been proposed, which could translate into more than 28 bcf/d of gas exports. However, the market is unlikely to need anywhere near that amount, with global LNG demand in 2012 at just over

<sup>2</sup> Macquarie Equity Research, *Global LNG Outlook*, 10 September 2012

250 mtpa, growing potentially to 400 mtpa by 2020 and to 500 mtpa by 2030. Clearly, firm off-take agreements will be critical for US projects to go forward.

Notably, Cheniere's Sabine Pass project is essentially sold out going forward; it has four proposed trains, totaling about 18 mtpa with four anchor buyers, along with some gas reserved for spot sales. General contract terms are based on Henry Hub spot prices, plus a 15% uplift for fuel use/shrinkage, along with a fixed liquefaction charge of US\$2.25 to US\$3/mcf.<sup>3</sup> Particularly important for proposed exports to Asia from the Gulf Coast will be the opening of the expanded Panama Canal in late 2014. (Most LNG tankers currently in use cannot use the existing canal. However, tolls will counter much of the distance/time advantages of the new canal.)

In Western Canada, four LNG export projects have been proposed, collectively with almost 50 mtpa of capacity, or about 7 bcf/d. As in the case of the US, not all projects are expected to go ahead. The proposed projects are underpinned by a large resource base in Western Canada, supportive government policy and a generally welcoming environment for foreign investment. The projects will however, be disadvantaged in comparison to their US competitors in that each of the Canadian projects will likely be an integrated greenfield project. Not only will the project developers construct the liquefaction/export facilities from scratch, they will also own and develop the gas resources. The projects will also require additional capital investment, likely from third parties, in the form of pipeline infrastructure from the gas source – presumably in

northeastern British Columbia (BC) – the Montney, Horn River and Liard basins in particular – to the export facilities. Such pipeline capital costs are estimated to add about US\$150 million to US\$200 million/mtpa to total projected costs.

Of the four Canadian projects, the Shell-led LNG Canada project at Kitimat is the largest, at 24 mtpa, or about 3.2 bcf/d. Shell's partners in LNG Canada include the Asian NOCs PetroChina and Kogas, along with the Japanese conglomerate, Mitsubishi. The Apache-led Kitimat LNG project, producing roughly 10 mtpa (about 1.4 bcf/d), is the furthest along in terms of regulatory approvals. The Kitimat LNG project originally included two other large North American E&P partners, EOG Resources and EnCana, but in late 2012, Chevron announced that it would buyout the interests of EOG and EnCana. Chevron will bring to the project extensive LNG experience and, importantly, existing relationships with potential Asian LNG buyers.

A third Canadian LNG export project, the Pacific Northwest LNG project at Lelu Island near Prince Rupert, BC, has been proposed by Petronas/Progress Energy, with planned capacity of 11 mtpa (about 1.5 bcf/d). The Canadian government recently approved the Petronas acquisition of Progress Energy, and in early January 2013, TransCanada announced that it would develop a natural gas pipeline from the Montney production region in northeastern BC to the LNG facility.

In offshore East Africa, the recent tremendously successful discoveries of natural gas are, in the words of the analysts at Macquarie, simply too big to overlook.<sup>4</sup> The discovered resource

<sup>3</sup> Deutsche Bank Markets Research, Global LNG, 17 September 2012

<sup>4</sup> Macquarie Equity Research, Global LNG Outlook, 10 September 2012

base could theoretically support exports of up to 70 mtpa, but since the exploration phase is far from over, that estimate could easily rise to 100 mtpa. More than 110 tcf of gas in place has been identified in offshore Mozambique, principally by separate consortiums led by Anadarko Petroleum (Rovuma Area 1) and Eni (Rovuma Area 4). Given the close proximity of the Mozambique discoveries, the export project economics will be strongly dependent upon the clustering of development and the extent of cooperation between operators. In late December 2012, Anadarko and Eni agreed to a cooperative development program for their adjoining offshore areas, and will together plan and construct a common onshore LNG liquefaction/export facility. The agreement should facilitate government approval of the developments.<sup>5</sup>

Particularly interesting to watch in early 2012 was the competition between Shell and the Thai NOC, PTT Exploration and Production (PTTEP), for the 8.5% Cove Energy interest in Anadarko's Rovuma Area 1 development in offshore Mozambique. After multiple bids and counterbids, Shell withdrew from further bidding. However, Shell is expected to continue to explore other options in the East African gas plays, with Shell's deep experience in LNG development and marketing expected to be particularly attractive to potential partners.

Neighboring offshore Tanzania has seen somewhat similar exploration success. But while some progress has been made in developing the fiscal framework and the gas commercialization agreements, more formal cooperation between the partnerships will likely be required, as a result of the distances between discoveries.

<sup>5</sup> IHS Global Insight, "Anadarko and Eni sign gas deal with Mozambique government, awards FEED contracts," 21 December 2012





# The overarching economic issues – costs and pricing

## Sticker shock – the capex challenge

The early wave of LNG projects were largely developed for capital costs of less than US\$200 million/mtpa of capacity, and with a few notable exceptions (e.g., Norway's Snøhvit and Russia's Sakhalin), the second wave of capacity was generally developed for costs in the US\$500 million to US\$1,500 million/mtpa range. The third wave of capacity is now challenged by what can only be described as a "step-change" in capital costs. Deutsche Bank estimates that the currently operating LNG projects were developed at an average cost of approximately \$1,200 million/mtpa, whereas the average cost for the recently sanctioned and proposed projects is more than US\$2,600 million/mtpa, more than double the historic average.<sup>1</sup>

LNG project proposals are growing faster than the industry's capabilities to develop them. Generally at the high end of the cost curve, with development bottlenecks and spiraling construction costs, Australian projects are typically suffering the most problems. Sanctioned projects are generally less significantly impacted (unless contracts are reopened or renegotiated), but projects still seeking contracted off-take are at substantial risk.

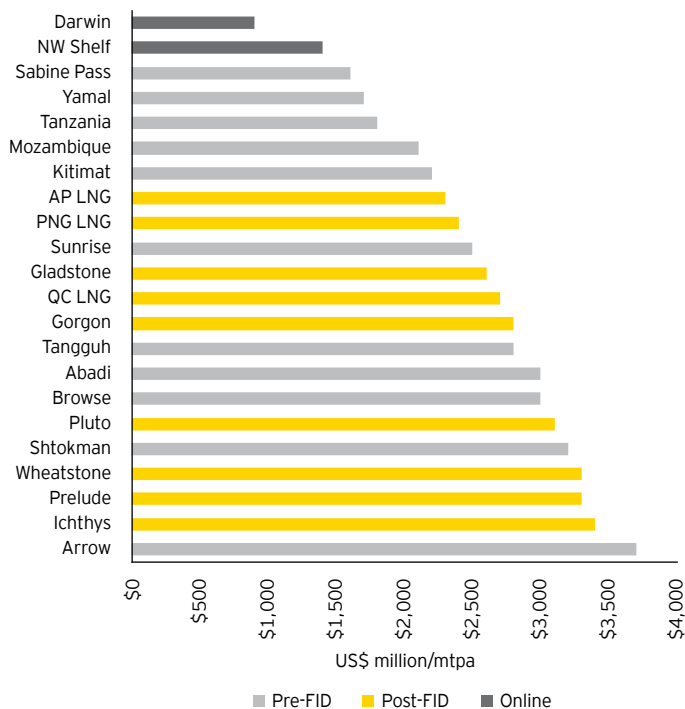
In contrast, brownfield projects that include expansions to existing operations and those that will build on existing LNG import infrastructure, such as in the US, will have distinct cost advantages. Similarly, merchant LNG projects that do not include the upstream costs of gas supply development, which again is the case for most of the US LNG export projects, will enjoy distinct cost advantages over the integrated projects.

According to analysts at Credit Suisse, the proposed North American and East African export projects are seen as particularly well positioned against the greenfield Australian projects, with unit costs (in terms of total costs to first LNG supply) averaging less than US\$2,000 per tonne, as opposed to the Australian average of more than US\$3,000 per tonne.<sup>2</sup>

<sup>1</sup> Deutsche Bank Global Market Research, *The Australian LNG Handbook*, 6 September 2011  
<sup>2</sup> Credit Suisse Global Equity Research, *Global LNG Sector Update*, 7 June 2012



**Figure 3. Total capital costs to supply: selected LNG projects**  
(total capex to first LNG supply)



Source: Credit Suisse Global Equity Research, Global LNG Sector Update, 7 June 2012

Costs in Australia have been driven up by inflation and currency shifts, as well as by local challenges of developments in remote areas with limited existing infrastructure and constrained access to equipment and skilled personnel. According to the International Monetary Fund, over the last 10 years, inflation in Australia has averaged more than 1% higher than the collective average for all of the advanced or developed economies.<sup>3</sup> Adding to the cost pressures, particularly in the last few years, the Australian dollar has significantly appreciated against the benchmark US dollar; since early 2009, the Australian dollar has strengthened by more than 65%.<sup>4</sup>

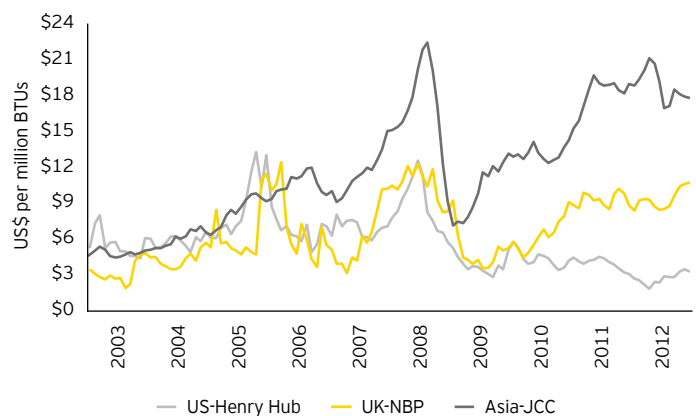
<sup>3</sup> International Monetary Fund, *World Economic Outlook* database, accessed 12 December 2012  
<sup>4</sup> Dow Jones Factiva, accessed 12 December 2012

## Indexing and convergence

The last few years have seen a record divergence in regional gas prices, driven by both supply and demand factors, e.g., the US shale gas boom, the European financial crisis and the Fukushima nuclear crisis.

The advent of diverse new supply sources is challenging the LNG status quo, with Asian buyers presumably looking to modify or possibly replace their long-standing and relatively expensive pricing model of gas prices tied explicitly to oil prices.

**Figure 4. Global natural gas prices (monthly averages)**



Source: US Department of Energy and Thomson/Reuters

High LNG development costs will require ironclad long-term off-take agreements. But more recently, the market is witnessing the inherent conflict of increasingly more expensive projects trying to sell to increasingly more price sensitive buyers. From the supply side, oil is becoming somewhat scarcer while gas is more plentiful. As a result, there is the inherent conflict of persistently high oil prices and a growing surplus of natural gas, with strict oil indexing becoming less tenable.

## Understanding Asian LNG pricing

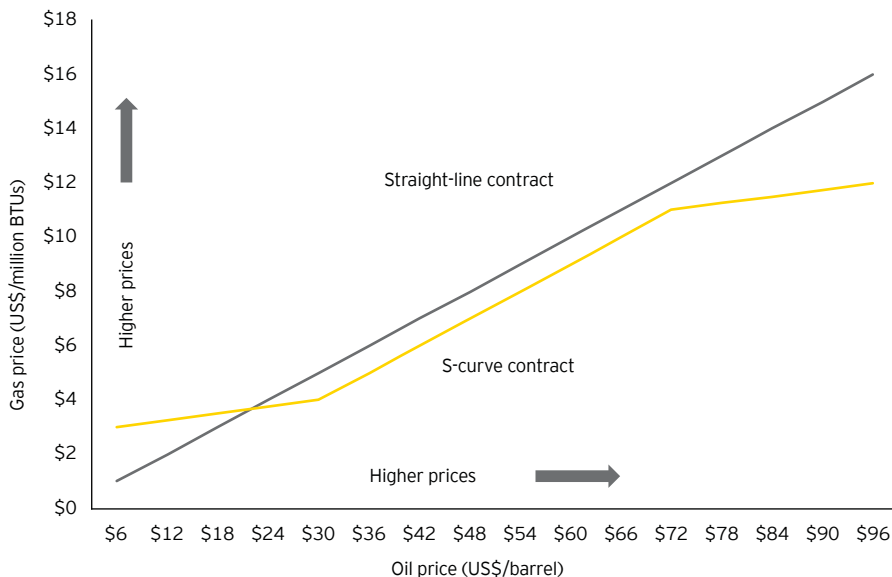
Long-term LNG contracts in Asia have historically been linked to prevailing crude oil prices, and while the concept is relatively simple, the actual derivation of the LNG price can be somewhat confusing. There are typically three pieces to the contract calculation: the oil price, the slope and the constant.

The calculation starts with an oil price reference benchmark; the one most commonly used is known as the Japan customs-cleared crude (JCC) price (also known as the Japanese Crude Cocktail). The JCC represents the average monthly price of a basket of various crude oils imported into Japan. The JCC typically moves in line with other global crude benchmarks.

The second contractual piece in the LNG price derivation is the negotiated factor, which is known as the "price slope." Slope essentially defines the relationship between oil and gas prices, and is then multiplied by the JCC. On average, one million BTUs of gas has about 16.67% of the energy content of a barrel of oil (i.e., the 6-to-1 heat-equivalent parity). Contract slope is typically expressed in percentage terms; thus, if the heat-equivalent parity were used, the slope would be 16.67%. Contract slopes are typically slightly less than 16.67%, usually around 14% to 15%, but they could be higher if the buyer were willing to pay a premium over the heat-equivalent oil price. As slope decreases, the resulting LNG price for a given oil price will be lower.

To further add complexity, some contracts will have varying slope percentages used at different oil price levels. Broadly speaking, there can be four basic forms: the simplest is a straight-line constant slope that exposes both the buyer and seller to adverse price movements. A second type is the so-called "S-curve," which will have a flatter slope at low oil prices to protect sellers and a flatter slope at high oil prices to protect buyers. The other two types are variations on the S-curve, where either only the seller has some protection (an oil-linked contract with a floor) or only the buyer has protection (an oil-linked contract with a ceiling).

Figure 5. Notional LNG contract slopes



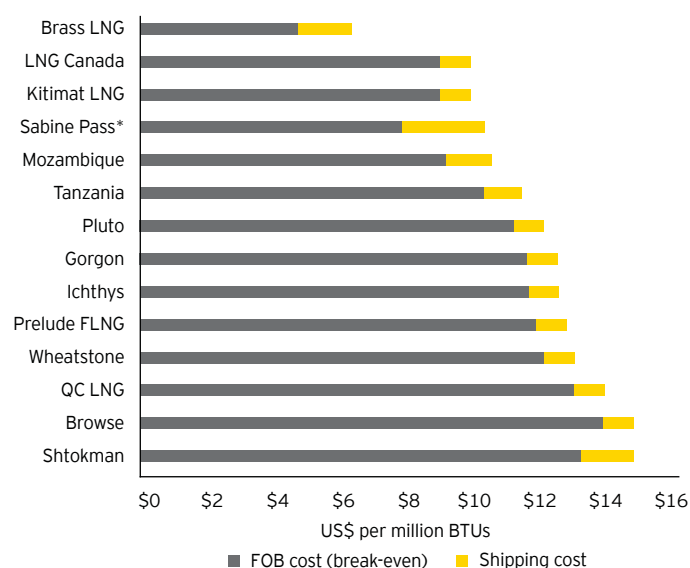
Source: Ernst & Young adapted from Deutsche Bank Markets Research, *The Australian LNG Handbook*, 6 September 2011

The final piece is the constant term, which generally represents a fixed price element that is independent of oil price movements. Most LNG contracts will include a modest constant, typically less than US\$1 per million BTUs, which generally bears some implicit relationship to shipping costs.

Oil indexation of gas contracts will become more difficult with greater competition between sellers; more price-sensitive buyers; increasing energy deregulation; increasing gas-on-gas competition from new pipeline infrastructure; increasing spot market liquidity; and, most important, increasing availability of spot-price-based LNG exports. Developers of high-cost projects will find it harder to find shelter in bilateral contracts and high-cost sellers will struggle to preserve pricing power.

Analysts at Deutsche Bank similarly see challenges for many of the proposed Australian LNG projects, looking at estimated nominal break-even costs, including an assumed 12% internal rate of return, and an assumed delivery into Tokyo Bay. In Deutsche Bank's view, the proposed North American LNG export projects are particularly well-positioned, even though the US Gulf Coast projects will give up some of their FOB cost advantage with higher shipping costs.

**Figure 6. Nominal new-build LNG costs: selected LNG projects**  
(assumes delivery to Tokyo Bay)



\*Assumes US\$4 Henry Hub spot gas

Source: US Department of Energy and Thomson/Reuters

The Deutsche Bank analysis suggests that the supply side of the LNG business needs to be assured that it will be able to achieve a netback (i.e., after shipping costs) of about US\$10 to US\$11 per million BTUs, or about US\$12 to US\$13 per million BTUs delivered. Given a broad assumption that long-term oil prices average between US\$80 to US\$90 per barrel, this would imply that sellers would seek oil-linked contracts with slopes in the range of 14% to 16%, approximately where they currently are.<sup>5</sup>

But the possibility of spot gas-linked contracts for North American LNG could upset the traditional pricing structure. Using the terms of the Cheniere Sabine Pass contracts, the attractiveness of "Henry Hub plus" pricing becomes apparent, both to buyers and sellers: buyers accessing supply not linked to high and presumably increasing oil prices, and sellers opening margin opportunities. As shown in the table below, the "plus" component or "uplift" over the spot price needs to be about US\$6 per million BTUs. Thus, US LNG will be particularly attractive if spot prices stay under or around the long-term US spot gas price assumption of about US\$5 to US\$6 per million BTUs.

**Table 2. US Gulf Coast LNG to Japan**

(US\$ per million BTUs)						
Henry Hub spot	\$2.00	\$3.00	\$4.00	\$5.00	\$6.00	\$7.00
Energy cost (15%)	\$0.30	\$0.45	\$0.60	\$0.75	\$0.90	\$1.05
Capacity charge	\$3.00	\$3.00	\$3.00	\$3.00	\$3.00	\$3.00
FOB cost	\$5.30	\$6.45	\$7.60	\$8.75	\$9.90	\$11.05
Shipping	\$2.50	\$2.50	\$2.50	\$2.50	\$2.50	\$2.50
CIF cost	\$7.80	\$8.95	\$10.10	\$11.25	\$12.40	\$13.55

Source: Deutsche Bank Markets Research, *Global LNG*, 17 September 2012

Notional FOB costs for proposed Western Canada LNG exports are assumed to be slightly higher than those for US Gulf Coast exports, largely due to the pipeline supply component (moving the gas from northeastern BC to the coast), but shipping costs to Asia are substantially lower. Total CIF costs of Canadian LNG to Asia are estimated to be US\$0.50 to US\$1.00 less per million BTUs than LNG from the US Gulf Coast.<sup>6</sup>

<sup>5</sup> Deutsche Bank Markets Research, *Global LNG*, 17 September 2012  
<sup>6</sup> Macquarie Equity Research, *Global LNG Outlook*, 10 September 2012

As substantial volumes of lower-cost LNG move into Asian markets, projects at the high end of the supply curve – namely, many of the Australian projects – will become increasingly vulnerable.

Going forward over the medium to longer term, we expect to see a gradual but partial migration away from oil-linked pricing to more spot or hub-based pricing. Alternatively, we are also likely to see some lowering of contract “slopes” (again, see the sidebar), which has the same effect. LNG sellers are reluctantly facing realities and are offering concessions in order to remain competitive. However, LNG prices are unlikely to collapse, simply because the cost to supply is high and incentives to develop new capacity must be maintained. As analysts at Macquarie point out, LNG is a very expensive game, and prices – however they are formed – must reflect this reality.<sup>7</sup>

Spot pricing increases buyers’ choices, adds liquidity to markets, and allows buyers to hedge financially and physically. The historic justification of oil linkages was the security of supply, but with increasing liquidity in the market, the security “premiums” become harder to justify. Growing liquidity also gives suppliers confidence to sanction projects before locking in off-take agreements – hence, the emergence of major portfolio LNG players. The opening of the Singapore LNG terminal in 2013 will presumably provide the basis/nexus for a sufficiently liquid regional exchange on which to base pricing. Additionally, some Asian buyers have already begun to sign contracts for future US-based cargos at Henry Hub-linked prices.

However, hub-based exports may not always be cheaper – e.g., US gas prices can be extremely volatile – and while greater contract flexibility is a big attraction, spot pricing could just interject more volatility for buyers and cause projects to have higher internal return thresholds to account for that volatility risk.

We are also expecting to see increasing destination flexibility in LNG contracts, increased “diversions” of cargos between markets and increased re-exporting of cargos, all of which increase liquidity and contribute to greater linkages between/among regions and markets. These increasing linkages between markets and the growing supply-side competition for premium Asian customers will provide some convergence of regional prices: namely, Asian prices are pushed down, while North American prices are lifted somewhat, generally narrowing, but not eliminating, the regional differentials.

<sup>7</sup> Macquarie Equity Research, *Global LNG Outlook*, 10 September 2012





# Other risks and challenges

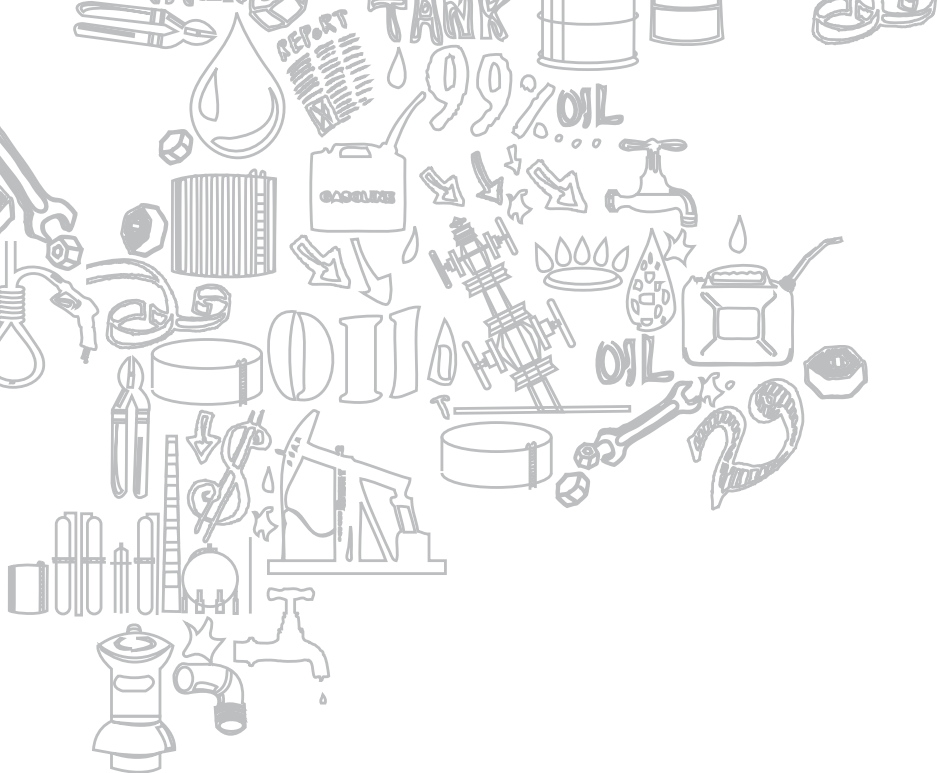
Beyond the cost and pricing issues, there are a number of other risks and challenges that companies have to consider and address:

- ▶ Price volatility – as noted earlier, spot prices, such as those in the US, can be very volatile, often affected by local supply/demand factors, abnormal weather or accidents.
- ▶ Political risk (exports) – particularly in the US, there may be domestic energy cost implications as a result of LNG exports. Gas-intensive industries that have recently gained competitive international advantage with low US gas prices are adamantly opposed to LNG exports. The recent study by NERA Economic Consultants for the US Department of Energy found that LNG exports would produce net economic benefits for the country despite somewhat higher domestic gas prices, and that these benefits would increase with export volumes.<sup>1</sup> While the findings of the report were welcomed by the LNG community, the report itself does not settle the politically charged issue. The US government always retains the right not to issue and/or to revoke export licenses. In addition, there simply are some concerns about the political “optics” of selling large amounts of gas to China.
- ▶ Political risk (environmental) – in Canada, these risks center around rising environmental opposition, particularly with regard to potential pipeline and/or shipping spills, and around First Nations’ land issues with the export facilities and the associated pipeline infrastructure.
- ▶ Calorific concerns with “lean” or dry gas such as from the US – Asian customers typically prefer “richer” gas. Technical workarounds may be effective, e.g., “spiking” dry cargos with natural gas liquids (NGLs).
- ▶ Transfer pricing – pricing is complicated by relatively illiquid markets with few participants and a paucity of comparable data. There are challenges in allocating or apportioning value and risk to the various functions along the supply chain in a long-dated contract. These issues can be magnified in the cases of cargo “diversion.”
- ▶ Skilled labor shortages – labor demands for the surge of Australian LNG projects have been a major factor in the cost inflation the industry has suffered. Even with much of the fabrication work done outside of Australia, labor demand is expected to remain extremely high through the end of the decade. In Canada, where skilled labor markets are already tightly stretched with oil sands construction activity, the knock-on effects of aggressive LNG development could substantially aggravate the problems and result in significant cost increases.
- ▶ Supply technology – two areas in particular could impact the future of LNG: methane hydrates and Floating LNG (FLNG). Over the long term, methane hydrates could potentially double the world’s natural gas resources. With a disproportionately large volume of methane hydrates located near Japan and Korea, both countries are ramping up R&D activities. Successful development could significantly reduce demand for LNG. FLNG may in some cases be an attractive, cost-effective alternative to land-based liquefaction, with potentially lower development costs, lower environmental impacts and the ability to monetize remote or smaller gas fields. At present, there are no operational FLNG facilities – Shell’s Prelude FLNG project, currently being developed in Australia, is slated to come online in 2017-2018.
- ▶ Immature fiscal/legal regimes in emerging gas markets – with East Africa emerging as one of the most promising new gas provinces, governments will be pressed to establish fair, transparent, and effective fiscal and legal systems. Failure to do so will likely slow LNG development.
- ▶ Potential LNG tanker capacity issues – industry will need one additional LNG tanker for ~1.5 to 2 mtpa of new capacity; this will depend on tanker size, with the biggest new tankers (Q-max tankers) holding up to 260,000 cubic meters, with the typical tanker size ~175,000 cubic meters. Tanker tightness could slow spot market liquidity growth.
- ▶ Checkered industry record in terms of schedule delays and cost overruns – Deutsche Bank notes that only 2 of the last 12 LNG projects have been delivered on time and budget, and it appears to be more difficult to do so. Projects are challenged by sheer train sizes, increasing technological complexity, labor issues and environmental issues, while upstream supply regions have also become more complex.<sup>2</sup> Analysts at J.P. Morgan similarly estimate that, since 2000, about one-third of all LNG projects have been delayed or over budget, or both.<sup>3</sup>

<sup>1</sup> NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States*, a report prepared for the US Department of Energy, 3 December 2012

<sup>2</sup> Deutsche Bank Global Market Research, *The Australian LNG Handbook*, 6 September 2011

<sup>3</sup> J.P. Morgan Cazenove Global Equity Research, *Global LNG*, 13 January 2012



# How can Ernst & Young help?

The technological, managerial and logistical challenges of complex energy mega-projects like LNG development are as significant as their potential. Companies and their partners will face a business and operational environment with increasing demands for adopting best management, planning and control practices. Ernst & Young can assist in overcoming key challenges, such as the following:

- ▶ Navigating and complying with complex tax systems
- ▶ Raising and managing capital
- ▶ Identifying, evaluating and completing a successful transaction
- ▶ Optimizing working capital
- ▶ Assessing and managing human capital requirements

To address these challenges and risks, Ernst & Young has established a global network of more than 9,000 dedicated oil and gas professionals in over 100 countries, supported by 12 Global Oil & Gas Centers.

Our oil and gas professionals are organized within four service lines: assurance, tax, transactions and advisory. Working in conjunction with local Ernst & Young staff, they bring both broad and deep oil and gas industry experience to the table, and extensive experience with the major industry players. Our experience and service offerings particularly relevant to the oil and gas sector and industry include the following:

## Advisory services

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- ▶ Risk advisory
- ▶ Performance improvement
- ▶ Information technology advisory

## Tax services

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- ▶ Domestic tax compliance
- ▶ International tax/transfer pricing
- ▶ Tax planning
- ▶ Human capital

## Transaction services

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- ▶ Transaction due diligence/support
- ▶ Transaction tax
- ▶ Capital transformation (including valuation, restructuring, merger integration)

## Assurance services

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- ▶ Statutory audit
- ▶ Internal audit
- ▶ Sustainability audit
- ▶ Fraud investigation and dispute services

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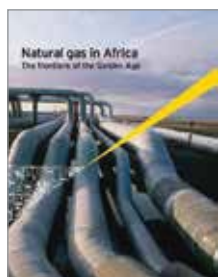
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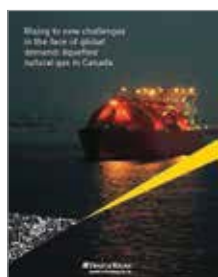
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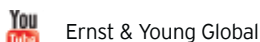
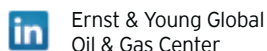
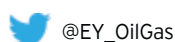


- ▶ **Natural Gas in Africa: The frontiers of the Golden Age** This new report spotlights Africa's rapidly evolving natural gas sector, with the continent seen likely to play an increasingly important role in what many have called the coming "Golden Age of Gas."



- ▶ **Rising to new challenges in the face of global demand: liquefied natural gas in Canada** This report provides a snapshot of how other LNG exporting countries are rapidly becoming a serious threat to Canadian firms and what Canadian LNG executives need to know.

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