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Implications of North American LNG Exports for Asia's Pricing Regime

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EXECUTIVE SUMMARY

This paper assesses potential exports of liquefied natural gas (LNG) out of North America and the possible implications for Asia's oil-linked LNG price structure.

Main Findings

As supply options in the traditional East of Suez region become more limited due to declining reserves and increasing domestic consumption, Asian buyers have expanded their horizons to new LNG-exports provinces such as North America and East Africa. North America has become especially intriguing as Asian buyers have taken stakes in oil and gas fields—particularly in Canada—and view North American supply as potentially cheaper than traditional supply options that are linked to oil. Given the cost structure of Canadian and U.S. projects, it is very likely that Canadian-sourced LNG will have to be largely, if not fully, linked to oil, whereas U.S. LNG exports will be linked to Henry Hub. High project costs for new plants, coupled with long-term LNG contracts that are currently in force, ensure that Asian LNG pricing will remain predominantly linked to oil for the foreseeable future, even when accounting for North American exports. While many buyers now seek hub-related pricing, some are under the impression that this price differential will last indefinitely and guarantee lower prices. FACTS Global Energy believes that the impact of U.S. LNG exports on Asian prices will be marginal. However, Asian buyers will look to add U.S. LNG into their portfolio as a price-diversification and supply-security strategy. In addition, U.S. LNG offers greater off-take flexibility as well as a negotiating tool when dealing with traditional exporters in the East.

Policy Implications

- In order to increase price and supply diversification and off-take flexibility, Asian buyers such as Japan that do not have free trade agreements (FTA) with the U.S. will press the U.S. government to allow non-FTA export licenses.
- U.S. restrictions on LNG exports would violate WTO rules, whereas by allowing exports the U.S. would increase trade balances and create jobs while having a marginal impact on the domestic price.
- British Columbia's proximity to the lucrative Asian market will give that province a transportation advantage over U.S. Gulf Coast projects. Yet with the window of opportunity closing, Canadian projects need to make final investment decisions in the next couple of years to capitalize on Asian LNG demand, which could be filled by other competing projects.

The Global Context of Asia-Pacific Energy Use

The Asia-Pacific region remains highly dependent on external energy supplies, particularly oil. **Table 1** illustrates that the gap between regional oil consumption and production is enormous and that reserves are not significant enough to raise production substantially.[1] The regional natural gas situation is more in balance than the oil market, but the region's share of consumption still exceeds its share of reserves, and this gap is expected to widen in the coming years. This means that, going forward, the region will require more imports of piped natural gas and liquefied natural gas (LNG). Nonetheless, coal is likely to remain an important fuel for the Asia-Pacific because a larger percentage of global coal reserves are found within the region than reserves of oil and natural gas. This underlines the key role of coal in the region's energy mix, particularly in countries with large populations and strong economic growth prospects such as China and India.

Table 1 *The Asia-Pacific region's global share of fossil fuel energy, 2010*

	Reserves		Production		Consumption	
	Amount[1]	Global Share	Amount[2]	Global Share	Amount[2]	Global Share
Oil	45.2	3.3%	399.4	10.2%	1,267.8	31.5%
Natural Gas	571.8	8.7%	443.9	15.4%	510.8	17.9%
Coal	265.84	30.9%	2,509.4	67.2%	2,384.7	67.1%
Fossil Energy Total			3,352.7		4,163.3	

[1] Oil: billion barrels; coal, billion tonnes; and natural gas, trillion cubic feet (tcf)

[2] mmtoe/y = million tonnes of oil equivalent per year

Source: *BP Annual Statistical Review of World Energy, 2011*

In 2011, natural gas constituted about 10% of primary energy consumption in the Asia-Pacific region, which is much lower than the global share of over 23%. While this is predominantly due to the greater distance in Asia between demand centers and supply sources, it once again highlights the growth potential for natural gas as the region continues to develop its appetite for the fuel. FACTS Global Energy (FGE) forecasts that gas consumption in Asia will grow by an annual average rate of 4% through 2030, led by the power and industrial sectors.

[1] Unless otherwise noted, the data in this paper is drawn from the author's research at FACTS Global Energy (FGE).

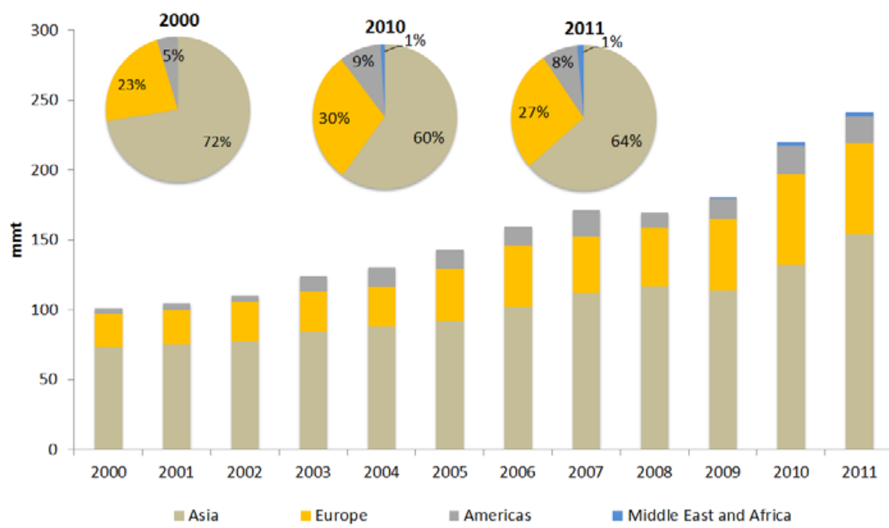
Efforts to increase the use of natural gas will continue whenever long-term economic and environmental benefits warrant it.

LNG Demand

Global LNG demand has grown by leaps and bounds since the first commercial cargo was shipped from Algeria to the United Kingdom in 1964. LNG trade that year was a mere 0.2 million tons (mmt), but 46 years later that figure swelled to nearly 220 mmt. Since the mid-1970s, Asia has overtaken Europe as the largest consuming region in the world. The Americas occupy third place, followed by the Middle East, which started LNG imports in 2009.

Global LNG demand breached the 100-mmt mark for the first time in 2000, with Asian LNG imports constituting nearly three-quarters of global LNG trade. At that time, there were only three Asian LNG-importing countries: Japan, South Korea, and Taiwan. These countries rely almost exclusively on LNG imports to meet their domestic gas needs. Most of their LNG requirements were met by long-term contracts from export projects located East of Suez. From 2000 to 2011, global LNG demand had grown at an average annual growth rate (AAGR) of around 8% to approximately 242 mmt (see **Figure 1**).

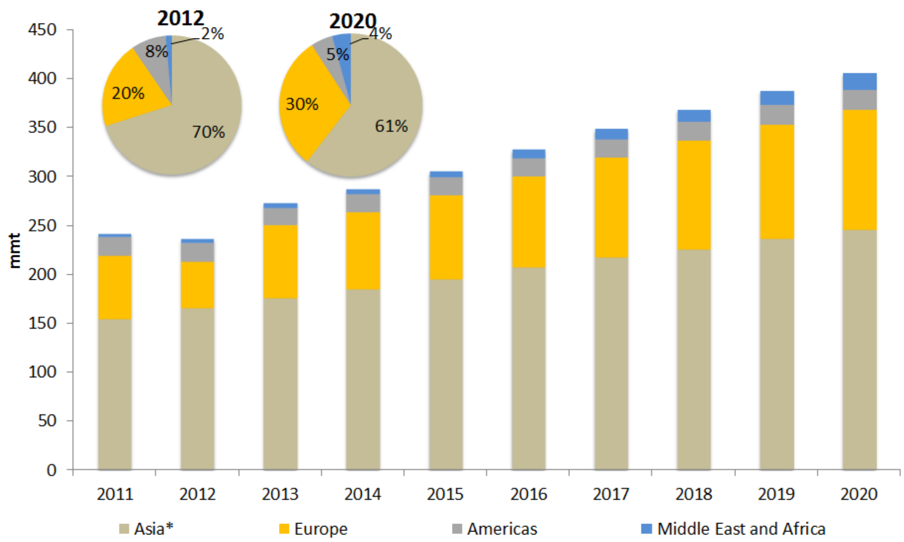
Figure 1 *Historical global LNG trade, 2000–2011*



Source: FGE.

Looking forward, FGE forecasts that global LNG imports will grow at an AAGR of around 7% during 2012–20 to over 400 mmt. Asia's dominance of worldwide LNG trade is expected to remain steady through 2020, even as Atlantic Basin and Middle Eastern demand rises. The region is still anticipated to be the world's largest demand center, accounting for most of the global LNG trade; maintaining about a 60%–70% share of the global market through 2020. Most new growth in LNG demand (in absolute terms) over this time frame is expected to come from Asia, followed by Europe, the Middle East, and the Americas (see **Figure 2**).

Figure 2 *Global LNG trade, 2011–20*



* Asia includes JKT + CN + IN + new markets (PK, SG, TH, VN, ID, MY, BD and PH).

Source: FGE.

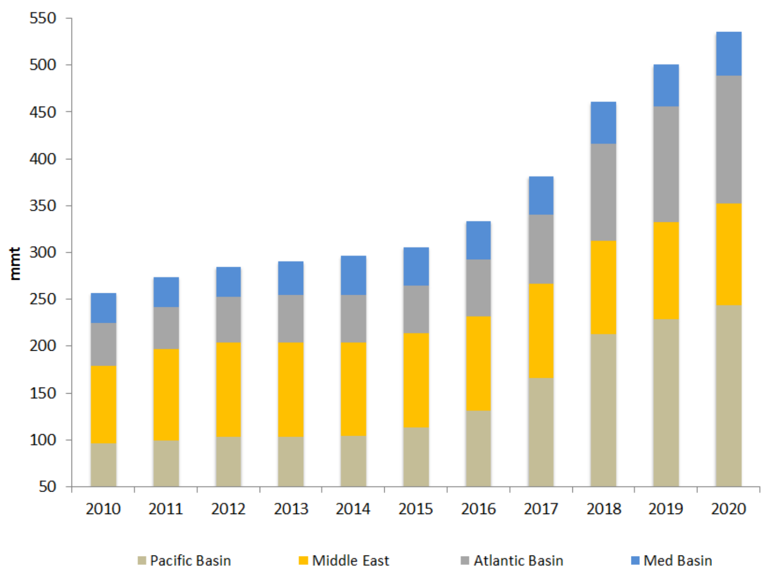
LNG Supply

As of 1997, there were only nine LNG exporters worldwide: Abu Dhabi, Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, Qatar, and the United States (Alaska). Since then, nine additional exporters have entered the market—Trinidad and Tobago and Nigeria in 1999, Oman in 2000, Egypt in 2005, Equatorial Guinea and Norway in 2007, Yemen and Russia in 2009, and Peru in 2010—thereby increasing the total number of LNG exporters to eighteen. Since 2006, Qatar has replaced Indonesia as the world's largest producer, accounting for over 30% of global LNG trade in 2011. The LNG industry witnessed an increase in nameplate capacities of nearly 9% annually during 2000–2010. The largest supply growth came from the Middle East region, both in percentage and absolute terms. Pacific Basin producers dominated the global LNG supply with about 38% of the world's nameplate capacity, followed by the

Middle East at a close second after the inauguration of most of the Qatari mega-trains. Global nameplate liquefaction capacity grew to an estimated 274 mmt by the end of 2011, which was a 7% increase from the 2010 level, as new liquefaction trains commenced operations and those that started in 2010 (e.g., Qatargas III, Qatargas IV, RasGas III, Peru LNG, and Yemen LNG) ramped up to capacity.

Looking forward, it is estimated that global nameplate liquefaction capacity will reach more than 285 mmt in 2012, an approximate 4% increase from 2011 levels. Between 2012 and 2015, around 32 mmt of additional LNG capacity, in the form of greenfield projects, is expected to come online. This will bring global nameplate capacity to over 300 mmt per annum (mmtpa) by 2015 (see **Figure 3**). The Pacific Basin region is expected to account for around 54% of this additional capacity, with the Mediterranean Basin and Atlantic Basin regions making up the balance.

Figure 3 *Current and future LNG nameplate capacity by region*



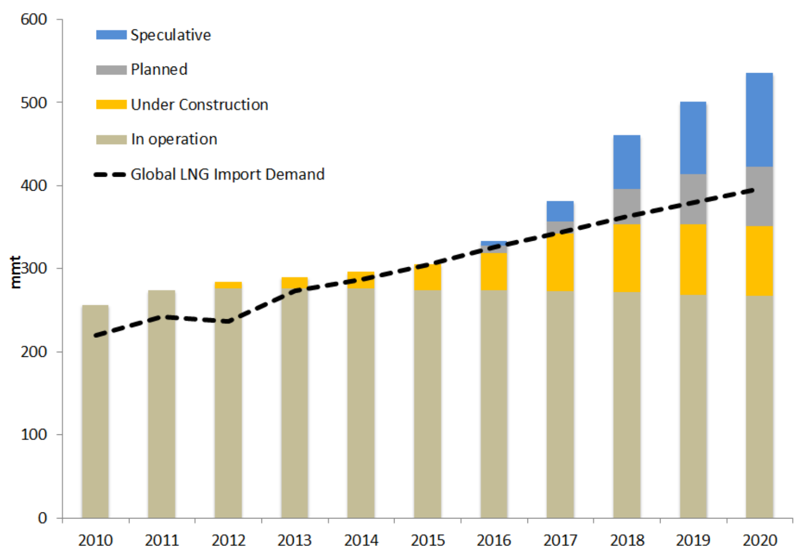
Source: FGE.

There are several other brownfield expansion and greenfield projects awaiting a final investment decision (FID) over the next few years, which are targeting start-ups post-2015. Though most of these planned projects are in the Pacific Basin, FGE foresees that projects from the United States will play an increasing role in terms of new supply capacity. Overall, during

2015–20, global LNG supply capacity may grow by 12% annually with the start of new LNG export projects and greater production capacity from existing projects.

A key factor affecting the outlook for LNG supply going forward will be the global balance of demand and supply. **Figure 4** compares FGE's projection of global supply capacity with projected demand for LNG imports and highlights a potentially tight market going forward, with projected demand trending extremely closely to supply capacity. This trend could drive sponsors of planned and speculative projects to quickly bring their projects into construction in a bid to capture incremental LNG demand within the market window. Additionally, this forecast for global LNG demand only includes "new markets" in Asia and could be much higher if it considered potential demand from "other Asian importers."

Figure 4 *Outlook for global LNG demand and supply*



Source: FGE.

Uncertainty over the global economy and concerns over rising engineering and construction costs may prompt prospective LNG exporters to exercise some caution going forward. However, project development in recent years has been helped along by the willingness of long-term buyers to acquire equity stakes in supply projects in addition to signing long-term sales agreements. Such strategies have helped some LNG export projects gain traction into the FID stage as equity stakes allow for buyers to receive some exposure to the upstream returns of the project as well as lift additional LNG volumes beyond what has been contracted. The sales agreements reached by three Australian project sponsors and their customers are perfect examples: Chubu Electric, Tokyo Gas, and Osaka Gas each took small stakes in Gorgon LNG, China National Offshore Oil Corporation (CNOOC) and Tokyo Gas acquired interests in Queensland Curtis LNG's upstream and downstream components, and in 2011 Sinopec bought 15% ownership interest in Australia Pacific LNG.

The final factor affecting the supply outlook will be potential export projects from North America. Although FGE considers U.S. projects to be mostly speculative at this stage (with the exception of Cheniere Energy's Sabine Pass LNG project), the huge supply potential cannot be denied. The shale gas revolution in the United States not only has greatly reduced the outlook for U.S. LNG imports but also could transform the country into a major LNG exporter. In addition, potential exports from Canada may be significant given the opportunity presented by the country's low gas prices and Western Canada's proximity to high-value Asian markets.

The United States

As of early February 2013, there were no less than 22 applications for LNG-export authorization pending before the U.S. Department of Energy (DOE), including small-scale ventures. In total, prospective U.S. LNG players have sought permission to export over 31.9 billion cubic feet per day (bcfd), or almost 235 mmtpa, of gas to countries with which the United States has a free trade agreement (FTA).[2] To understand how massive this figure truly is and view U.S. LNG export plans in the context of the global LNG market, consider that world LNG trade in 2011 was almost 242 mmt. The scale of proposed development of liquefaction capacity in the United States is truly unprecedented in the roughly 40-year history of the global LNG trade. Applications to export domestically produced LNG to countries with which the United States does not have an FTA total 24.8 bcfd (or 183 mmtpa). These projects represent the nation's current LNG export potential, which as a whole remains a topic of great debate for

[2] Countries that have FTAs with the United States include Australia, Bahrain, Canada, Chile, Costa Rica, Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Singapore, and South Korea. Only six of these eighteen countries import LNG or have regasification terminals under construction. Countries pending congressional approval for FTAs include Panama and Colombia. The United States is also negotiating a regional FTA, the Trans-Pacific Partnership (TPP), with several countries, including Malaysia and Singapore. Several other countries, including major existing or potential future LNG importers such as Japan, South Korea, Taiwan, and the Philippines, have also expressed interest in TPP membership.

many reasons: the availability of shale gas production for the export sector, the effect of exports on U.S. gas prices, the ability of project sponsors to capitalize on their strengths and overcome any weaknesses, and the impact of U.S. LNG sales on long-term global pricing trends, to name but a few.

With the exceptions of a proposed greenfield Alaskan LNG project, two planned Oregonian LNG ventures on the Pacific Coast, and proposals to reconfigure the existing Cove Point and Elba Island ventures on the eastern seaboard as bidirectional facilities, the U.S. Gulf Coast is the favored location for U.S. LNG-export projects. Out of the twenty baseload projects under development, fifteen are located on the Gulf Coast; this region was, after all, the focus of import terminal developers' attention during the 2000s. The U.S. Gulf Coast is also located in close proximity to sources of gas supply such as the Barnett, Eagle Ford, and Haynesville. Moreover, the region is comparatively receptive to petroleum industry–related development such as shale gas exploration and production and takeaway infrastructure construction and modification. As such, the Gulf Coast is a favorable location for siting and construction, though not as desirable for reaching coveted Far East markets as proposed facilities on the Pacific Coast.

U.S. LNG exporters require approval on a multitude of regulatory issues before their plans can become reality. The DOE must sign off on applications to export domestically produced LNG abroad. Permission to export LNG to countries with which the United States has an FTA is easy to obtain, but DOE approval for exports to non-FTA countries is harder to come by. To date, 22 exporters have sought permission for FTA and/or non-FTA LNG exports, but only one project (Sabine Pass) so far has secured both FTA and non-FTA authorization from the DOE. The remainder await rulings by the DOE, which will not be forthcoming until it has digested the contents of a study that analyzes the macroeconomic effects of U.S. LNG exports. It was widely expected by industry pundits that this study would be submitted sometime in summer 2012, thereby equipping the DOE to process more LNG-export authorizations before the end of that year. However, the study's results were not announced until early December 2012. Taking into account the U.S. presidential election in November 2012, end-of-the-year holiday festivities, the study's two-and-a-half month comment period, and the presidential inauguration in late January 2013, a decision by the DOE on the next tranche of pending LNG-export authorizations probably cannot be expected until at least the second quarter of 2013. The DOE will act on applications that have commenced the pre-filing process with the Federal Energy Regulatory Commission (FERC) in the general order in which the DOE received them. Projects that have not initiated the FERC process (and any others submitted) will be dealt with subsequently in the order received.

Developers must also secure a certificate of public convenience and necessity from FERC to build an LNG-export terminal. FERC's mandate is to ensure the safety of the public and the environment. As long as a project meets specified safety and security parameters, FERC will grant the requisite license. It is, of course, possible for state or local authorities to withhold their consent and effectively derail a project. FERC has "exclusive authority under the Natural Gas Act to authorize the siting of facilities for imports or exports of LNG. But that authorization is conditioned on the applicant's satisfaction of other statutory requirements for various aspects of the project. Substantial authority exists through current federal statutes pertaining to those aspects of the project for states to authorize or block and thereby effectively 'veto' development of an LNG facility."[3] In other words, states have the power to deny the applicant permits associated with the Clean Water Act, the Coastal Zone Management Act, and the Clean Air Act. This could be an issue for LNG-terminal developers seeking to build greenfield facilities in locales that refused to host LNG-import infrastructure during the import-terminal building boom witnessed in the 2000s, but should be less of an issue for reconfiguring existing facilities as bidirectional terminals. As of early February 2013, almost a dozen LNG exporters had applications at various stages of development pending before FERC; only one (Cheniere's Sabine Pass LNG project) has won full FERC approval, as shown in **Table 2**. FGE believes that FERC will follow the practice established during the previous decade's building boom, when certificates were granted to every developer that passed muster, and the market effectively decided which facility was built.

[3] See the "Laws and Regulations" page on the FERC website, http://ferc.gov/industries/gas/indus-act/lng/state-rights.asp.

Table 2 *Status of planned U.S. LNG-export projects*

Regulatory Process	Sabine Pass LNG	Freeport LNG	Freeport LNG Expansion[1]	Lake Charles Exports/Trunkline LNG (TLNG) Exports[3]	Cameron LNG	Jordan Cove	Corpus Christi LNG	Dominion Cove Point	Oregon LNG	Lavaca Bay LNG	Southern LNG Company (Elba Island)
FERC Application	✓	Filed FERC application for facility construction	×	Initiated FERC Pre-Filing	Filed FERC application for facility construction	Initiated FERC Pre-Filing	Filed FERC application for facility construction	Initiated FERC Pre-Filing	Initiated FERC Pre-Filing	Initiated FERC Pre-Filing	Initiated FERC Pre-Filing
FERC Approval	✓	×	×	×	×	×	×	×	×	×	×
DOE Authorization to Export LNG to FTA Countries*	✓ (16)	✓ (9)	✓ (9)	✓ (15)	✓ (12)	✓ (6)	✓ (15)	✓ (7.82)	✓ (9.6)	✓ (10)	✓ (4)
DOE Authorization to Export LNG to non-FTA Countries*	✓ (16)	Under DOE Review (9)	Under DOE Review (9)	Under DOE Review (15)	Under DOE Review (12)	Under DOE Review (6)	Under DOE Review (15)	Under DOE Review (7.82)	Under DOE Review (9.6)	Under DOE Review (10)	Under DOE Review (4)
Deals Announced	✓	✓	×	✓	✓	×	×	✓	×	×	×
Regulatory Process	Gulf LNG	Golden Pass LNG	Gulf Coast LNG	CE FLNG	Waller Point LNG	Pangea LNG	Alaska Gasline Port Authority	Main Pass Energy Hub[2]	Magnolia LNG	Gasfin LNG Export Project	
FERC Application	Initiated FERC Pre-Filing	×	×	×	×	×	×	N.A.	×	×	
FERC Approval	×	×	×	×	×	×	×	N.A.	×	×	
DOE Authorization to Export LNG to FTA Countries*	✓ (11.5)	✓ (15.6)	✓ (20.4)	✓ (8)	✓ (1.25)	Under DOE Review (8)	Pending Approval (19)	✓ (24)	Under DOE Review (4)	✓ (1.5)	
DOE Authorization to Export LNG to non-FTA Countries*	Under DOE Review (11.5)	Under DOE Review (15.5)	Under DOE Review (21.4)	Under DOE Review (8)	×	Under DOE Review (8)	×	×	×	×	
Deals Announced	×	×	×	×	×	×	×	×	×	×	

* Total export volumes submitted to DOE, mmtpa.
[1] Freeport (FLEX) submitted a new application to export an additional 1.4 bcf/d of LNG from new trains to be located at the Freeport LNG Terminal. Freeport (FLEX) submitted pre-filing with FERC for 13.2 mmtpa but has received export permission from the DOE to export a total of 18 mmtpa (including expansion) to FTA countries.
[2] Not subject to FERC jurisdiction
[3] Trunkline LNG Exports applied for FTA exports of 15 mmtpa via Lake Charles terminal. Volumes are non-additive and only for maximizing optionality to expand customer base for LNG exports from the Lake Charles terminal. Pending approval

Source: FERC and U.S. DOE.

While most of the aforementioned projects are greenfield facilities or reconfigurations of existing import facilities, one U.S. state has been exporting LNG for many years. Alaska has long been an LNG exporter. The 1.5-mmtpa Kenai LNG plant started operating in 1969 and continued to ship LNG to Japan until the plant was idled in November 2011 because of gas feedstock shortages and problems acquiring shipping contracts. The plant reopened in February 2012. However, its license to operate expires in 2013, and there is doubt about whether there is enough gas to keep the plant running.

The major promoter of the new greenfield LNG project is the Alaska Gasline Port Authority (AGPA). AGPA has applied to the U.S. DOE for export authority, as illustrated in Table 2. The overall project, if it is built, will be staggeringly expensive. Costs of $45-65 billion, in addition to the pipeline, are being quoted, bringing the anticipated price tag to $71–$91 billion. Many analysts are privately beginning to refer to the project as a $100-billion proposition.

If the go-ahead were given today, it is generally estimated that the construction time would be at least ten years, meaning that the earliest LNG would be available from the project would be 2022. Most analysts consider 2022 quite optimistic; according to one straw poll, on-stream dates of 2025 to 2030 or later are likely. If the above cost estimates are correct, the AGPA LNG project will require oil indexation and probably a somewhat higher crude-oil linkage than Australian or Canadian projects presently on the books.

Canada

A number of Canadian entities have floated plans for developing LNG-export capacity in the region. The vast majority of this capacity is based on the promising unconventional gas deposits of British Columbia and Alberta: namely, the Horn River, Cordova Embayment, Liard, Doig, and liquids-rich Montney tight gas and shale plays. One or two projects are located on Canada's east coast in the hope of monetizing gas from the Marcellus shale in the United States, the Utica shale that straddles the United States and Canada, and perhaps even the Horton Bluff formation in Canada's Maritime provinces. There are almost a dozen planned Canadian LNG-export projects (see **Table 3**). Only a few projects have provided details of planned send-out capacity, which totals over 65 mmtpa, although this figure will of course increase as existing projects acquire greater scope and definition. Given that only one small Canadian project has announced a definitive sale and purchase agreement (SPA) with a buyer, on paper Canadian projects remain more or less fully uncommitted.

Table 3 *Planned Canadian LNG-export projects*

Project	Nameplate Capacity (mmtpa)	Sponsor	Sponsor's Start-Up Date	Status	Comments
Kitimat LNG	11	Chevron, Apache	2018-2019	Planned	Government export approval granted. Terminal could be ready 4½-years after a final investment decision is made.
BC LNG	1.8	Douglas Channel Energy Partners (DCEP)	2015	Planned	Government export approval granted. Sales contract with Golar LNG announced in early 2013.
LNG Canada	24	Shell, Korea Gas, Mitsubishi, and PetroChina Company	2019-2022	Planned	LNG export application obtained in February 2013. TransCanada tapped to build the $4 billion CoastalGas pipeline from the Montney Shale to planned liquefaction site at Kitimat.
Pacific Northwest LNG	7.6	Progress Energy/Petronas	2018	Planned	Plans for a third, 3.8 mmtpa train also. Potential exists for individual trains to be resized to 6 mmtpa. TransCanada will build the $5 billion Prince Rupert Gas Transmission pipeline to support the project.
Prince Rupert LNG	TBD	BG	2020	Planned	BG has signed a Project Development Agreement with Spectra Energy Corp for a new natural gas transportation system from northeast B.C. to Prince Rupert. The approximately 850-kilometre (525 mile), large diameter natural gas transportation system will begin in northeast B.C. and end at BG Group's potential LNG export facility in Prince Rupert. Capacity is 4.2 bcf/d.
Nexen/INPEX	TBD	TBD	TBD	Planned	No specific plans yet.
TBD	11	Imperial Oil (75%-owned by XOM) and XOM	TBD	Planned	Imperial, when combined with parent Exxon Mobil Corp., has dibs on 340,000 hectares in the Horn River. There's also scope for more feedgas availability: Exxon Mobil Canada made in October 2012 a C$3.1 billion (US$3.15 billion) offer for gas-weighted Canadian junior Celtic Energy in seeming preparation for an LNG export bid, probably located around Kitimat.
Goldboro LNG	10	Pieridae Energy	Late 2018	Planned	Originally a planned LNG import terminal in Nova Scotia. Project will be anchored by gas from the Maritimes&Northeast Pipeline that currently feeds Canadian gas production and imported LNG into the Northeast US.
Bear Head LNG (?)	TBD	Anadarko?	TBD	TBD	US independent Anadarko Petroleum mothballed its Bear Head LNG import terminal project in the eastern Canadian province of Nova Scotia in 2007, but the company filed a request in late 2012 to extend its construction permit at the site to 2015. No definitive plans for an export terminal have been formally announced, however.
AltaGas Idemitsu Joint Venture Limited Partnership	TBD	Idemitsu and AltaGas	2017	Planned	Project could include LNG and LPG exports. Feasibility studies scheduled for completion in 2014. Feedgas pipeline will be provided by AltaGas' wholly owned subsidiary Pacific Northern Gas Ltd.
Talisman Energy	TBD	Talisman, TBD?	TBD	Planned	Company has acreage in the Montney and Duvernay formations. Elected not to join Sasol Canada in a two-phase, 96,000–bpd GTL plant after performing a feasibility study in 2012. May be even more amenable to an LNG plant instead, but no concrete project plans have been laid. May seek partners in upstream acreage - this could galvanize LNG plans.

Source: FGE.

Almost all these projects are sponsored by companies with not only significant upstream Canadian shale gas assets but also in some cases a well-established role in the LNG business. The strength of the various project sponsors will undoubtedly affect these projects' prospects for success. However, each project also faces common challenges: namely, the sheer remoteness of the shale plays, the potentially high break-even costs for producing the gas, a comparative lack of gas-delivery infrastructure, and, of course, high development costs. This combination of factors may render a Canadian facility a less favorable choice to be a supplier than a facility located in the United States.

In order to circumvent the challenges of more costly development of upstream and greenfield liquefaction, virtually all Canadian LNG-export consortia have resolved to index LNG sales to crude oil. The need for oil indexation is all the greater considering the local AECO-C hub's historical discount to Henry Hub, rendering local hub-based pricing for Canadian shale gas production and LNG sales even more impractical.[4] However, this approach has not been received kindly by prospective Asia-Pacific LNG buyers. Given the significant disconnect

[4] The AECO hub is the largest Canadian hub for natural gas and is the largest foreign supply of natural gas to the United States. Over the last ten years, AECO prices have averaged $0.80 per mmBtu (million British thermal units) less than Henry Hub prices.

between world oil prices and hub-indexed gas prices in North America and northwestern Europe, Far East LNG buyers are agitating for the inclusion of Hub indexation on future LNG-supply contracts rather than 100% crude oil indexation. It appears that the willingness of U.S. LNG sellers to adopt Henry Hub indexation for LNG sales has helped stall marketing initiatives for more advanced Canadian players like Kitimat LNG. All in all, these are significant barriers to entry, but Canadian sellers also enjoy some advantages relative to the United States that in FGE's estimation will result in at least one or two successful projects by 2020.

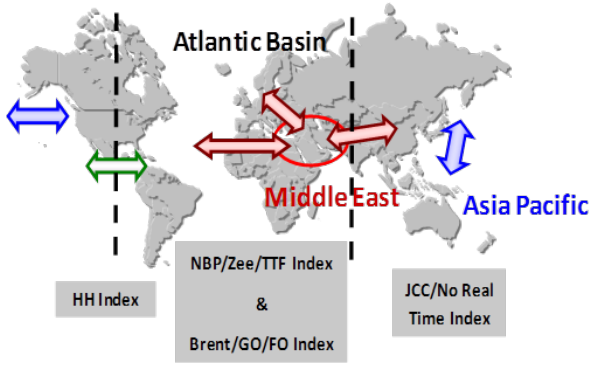
Overview of Regional Natural Gas Prices

Although natural gas is traded internationally, access to gas imports is far more restricted than access to oil imports. Almost every seaport in the world can import at least some volume of oil products; oil transport and storage use relatively simple and cheap infrastructure unlike LNG, which requires specialized and expensive infrastructure due to its cryogenic nature. The need to keep gas under pressure means that the only cheap place to store gas is underground. Traditionally gas was moved by pipeline, and pipelines today continue to carry around 70% of international gas trade. The other 30% of trade is via sea in the form of LNG. Although LNG still constitutes less than a third of world gas trade, LNG trade in 2010 expanded by 22%, compared with a 5% expansion in pipeline gas trade.

For reasons of physical geography, much of the world is not suitable for pipeline trade in gas. Political geography can be an even greater challenge. Over the years, many plans for exports of gas via pipeline from the Middle East—such as the Iran-Pakistan-India "peace pipeline"—have foundered on the hard reefs of political realities.

In principle LNG offers greater freedom of trade, but today there are only eighteen LNG exporters in the world and fewer than one hundred regasification plants. Many of the world's largest gas producers do not have gas liquefaction. With limited pipeline connections in many areas and limited trade in LNG, the gas market is inherently fragmented. In early 2012, gas was sold into Japan for as high as $18 per million British thermal unit (mmBtu) at the same time that wholesale prices were $9 per mmBtu in the United Kingdom, less than $2 per mmBtu in the United States, and $0.75 per mmBtu in Saudi Arabia. Currently, Europe, Asia and the United States each has its own unique pricing index, as illustrated in **Figure 5**.

Figure 5 *Different gas pricing indices used across regions*



Source: FGE.

Although the market is fragmented, certain hubs are generally taken as representative of the base price in a given region. In the United States, prices are generally linked to the spot prices at Henry Hub, which is a physical hub in Louisiana that interconnects thirteen major pipeline systems.

The price of gas at various points in the continental United States is generally given as a differential from Henry Hub. Henry Hub also serves as the delivery point for New York Mercantile Exchange futures contracts in natural gas. Because of the transparency of the Henry Hub spot market and the high liquidity offered by both spot and futures trades, Henry Hub is increasingly being used as a reference point for other gas contracts in the Western Hemisphere. Most LNG sales into North America are tied to Henry Hub prices, because those are the prices with which imports must compete.

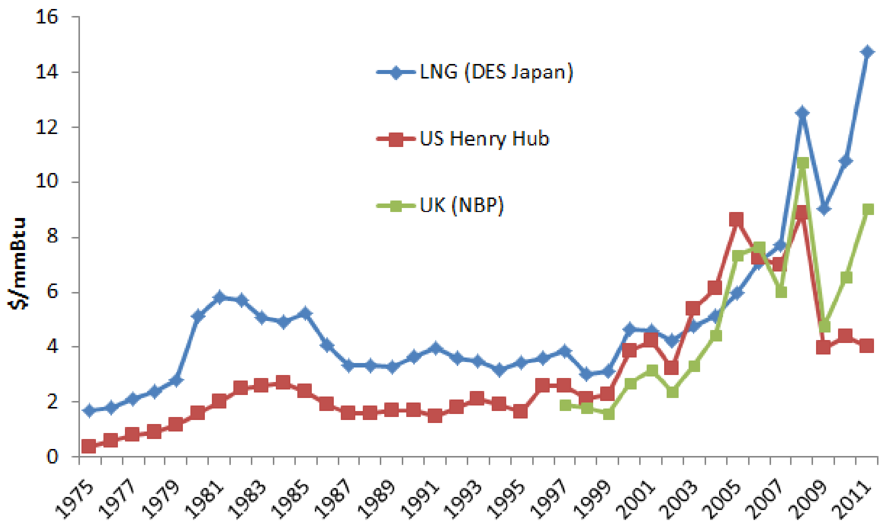
In Europe, the liberalization of the natural gas market has led to the emergence of spot markets, mostly in northwest Europe (mainly the United Kingdom, Belgium, and the Netherlands). The most widely referenced price is the UK National Balancing Point (NBP), a notional point in the transportation system. In Belgium, natural gas is traded at the Zeebrugge Hub, whereas the Title Transfer Facility (TTF) is a virtual trading point for natural gas in the Netherlands. In these countries and nearby areas, LNG contracts tend to be tied to those prices. The emergence of these markets is a comparatively recent phenomenon, however; in much of continental Europe LNG contract prices continue to be set by linkages to Brent or to the spot prices of gas oil and fuel oil.

In many ways, Europe is the most complicated of the regional gas markets. There is substantial production in Europe itself (especially in the North Sea), along with significant imports via pipeline. Russia is the largest supplier, but there are also significant imports from North Africa, and Turkey imports pipeline gas from Iran. Europe also imports substantial volumes of LNG from Africa, the Middle East, the Americas, and on occasion from as far away as Australia.

Asian LNG prices are generally linked to crude oil prices—in particular to the Japan Custom Cleared price (JCC), also referred to as the "Japan crude cocktail" price. The JCC is the average price of crudes imported into Japan every month and is published by the Ministry of Finance on a monthly basis. Japan is the largest importer of LNG in the world and accounts for over half of all the LNG imports in Asia. As discussed earlier, Japan, South Korea, and Taiwan have virtually no domestic gas production, no pipeline connections to other countries, and virtually no domestic oil production. These three countries have long formed the dominant LNG-importing group in Asia, but they have recently been joined by China, India, and Thailand—countries that are short of energy resources but nonetheless have substantial domestic production.

Figure 6 shows the key indicator prices for natural gas in the three major regions. As with most energy commodities, the history of international energy prices can be seen in the high prices of the early 1980s and in the first decade of the 2000s. However, the correlations with the history of the oil market are not tight and the relationships are far from simple.

Figure 6 *Comparison of regional natural gas prices*



Source: BP Statistical Review 2012.

For most of the last three decades, the United States and Europe experienced much lower gas prices than Asian importers. While Japanese LNG imports were firmly tied to crude, gas prices in the United States and Europe were competing against pipeline supplies. This long-standing relationship was reversed for the first time in 2003 in the face of North American gas shortages, driving Henry Hub prices above Japanese LNG imports. In 2005, Hurricane Katrina drove U.S. gas prices to record levels. Because at the margin the United States was reliant on LNG imports, competition for Atlantic Basin supplies carried UK National Balance Point (NBP) prices up as well. There were projections that the Atlantic Basin would begin to operate as an integrated regional gas market and that the LNG trade would increasingly integrate international gas prices. Yet as Figure 6 shows, by 2008 this trend evaporated, and Atlantic Basin prices dropped back below Asian LNG prices. Moreover, U.S. prices at Henry Hub moved off on their own trajectory, falling even as Japanese and NBP prices soared.

The cause of the change was the U.S. shale gas revolution. As **Figure 7** shows, after 2007 shale gas production entered a period of explosive growth, augmenting stagnating supplies of tight gas and slow-growing supplies of coalbed methane. Unconventional gas (shale plus coalbed methane) accounted for about 41% of the total U.S. gas supply in 2012, and shale gas alone accounted for 34% of total production. In coming years, shale gas will continue to experience the strongest growth rates of all unconventional gas sources and is forecast by the U.S. Energy Information Administration to account for nearly 50% of the total U.S. gas supply by 2035.

Figure 7 *Unconventional gas supply in the United States*

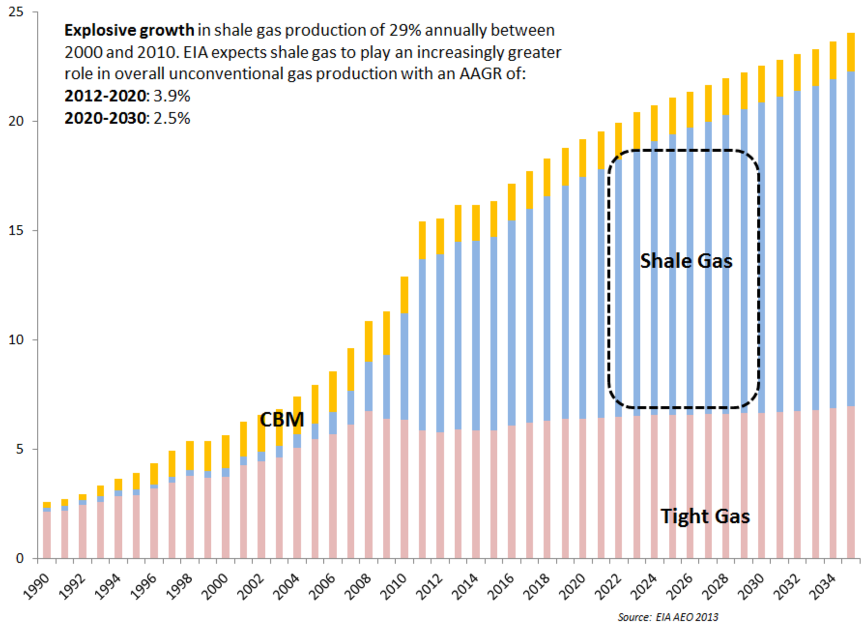
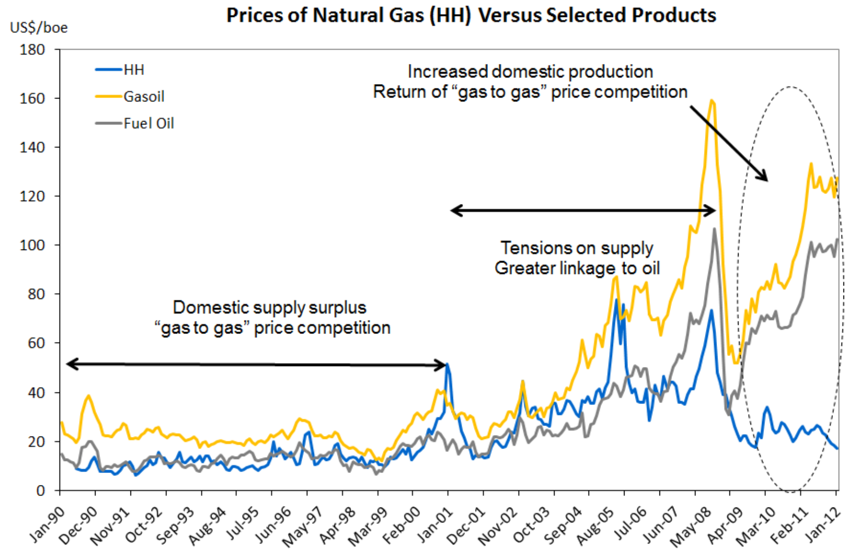


Figure 8 shows the history of Henry Hub pricing against the prices of gas oil and fuel oil from 1990 to the present. Through the 1990s, Henry Hub prices were determined mainly by competition between North American sources of gas (including pipeline imports from Canada). As discussed above, supply shortages and increased reliance on marginal imports of LNG raised U.S. prices sharply through 2008, but since that time oil prices have surged while gas prices have fallen sharply.

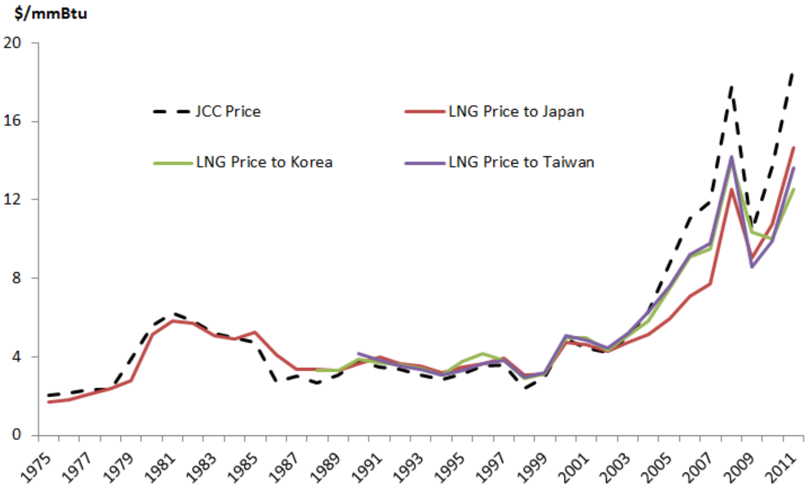
Figure 8 *Decoupling of U.S. prices from oil prices*



Source: FGE.

LNG prices in Asia followed a very different path. Higher oil prices resulted in higher LNG prices, but not on a one-to-one basis. Many Asian LNG contracts are linked to oil by "S-curves," which provide floors and ceilings in the direct linkage of prices to the JCC. During 2003–7, these were a factor in allowing Henry Hub prices to climb above Asian LNG prices. In the face of higher oil prices, this discount relative to crude tended to strengthen Asian demand for LNG. The discount, however, has been eroded in recent years. As **Figure 9** shows, some Japanese contracts came due for renegotiation in 2010, and this tended to produce a bump in pricing levels, taking Japanese prices above Korean and Taiwanese levels. This increase in prices was exaggerated by Japan's 2011 earthquake and tsunami, followed by the Fukushima disaster, which drove up Japanese LNG requirements. The additional supplies were obtained primarily through new short-term and mid-term contracts, often at prices well above those offered by existing long-term contracts.

Figure 9 *Kick-in of S-curves in long-term Asian contracts*



Source: FGE.

In summary, although many expected a gradual convergence of prices in the main regional gas markets, the last few years have seen a great divergence. In 2011, Japanese prices were almost $15 per mmBtu, Henry Hub prices were a little over $4 per mmBtu, and UK NBP prices were a little over $9 per mmBtu. In 2012, Japanese prices have continued to increase, U.S. prices have continued to fall, and NBP prices have remained generally steady. The three distinct regional markets for gas have thus been restored, and the expected increase in shale gas output in the United States in coming years will ensure that they will maintain very different pricing regimes. This massive disconnect between Hub prices in the United States and Canada versus oil-linked prices in Asia is what is driving the LNG-export proposals in North America.

Potential Implications of North American Exports for Asia's Pricing Regime

Canada vs. United States

The enormous disconnect between gas prices in North America and those in other regions is a driving force behind most LNG-export proposals in Canada and the United States. Both countries have their advantages and disadvantages from a buyer's perspective. In Canada, gas supply is plentiful and cheap; LNG projects enjoy government support at the provincial and federal levels; lobbying against LNG exports is minimal to nonexistent; gas quality is not an issue, given the distinct upstream and downstream components akin to a traditional LNG project;

and western Canada is closer to Asian markets than most of the proposed U.S. LNG-export terminals. However, unlike in the United States, all Canadian projects will be greenfield developments and therefore will take longer to build and cost more. Dedicated gas pipelines must be built to export gas located hundreds of kilometers away from the coast, and contrary to popular belief there is a risk of revocation of the export license. The maxim that Canada is easier and less political in terms of LNG than the United States is thus misleading.

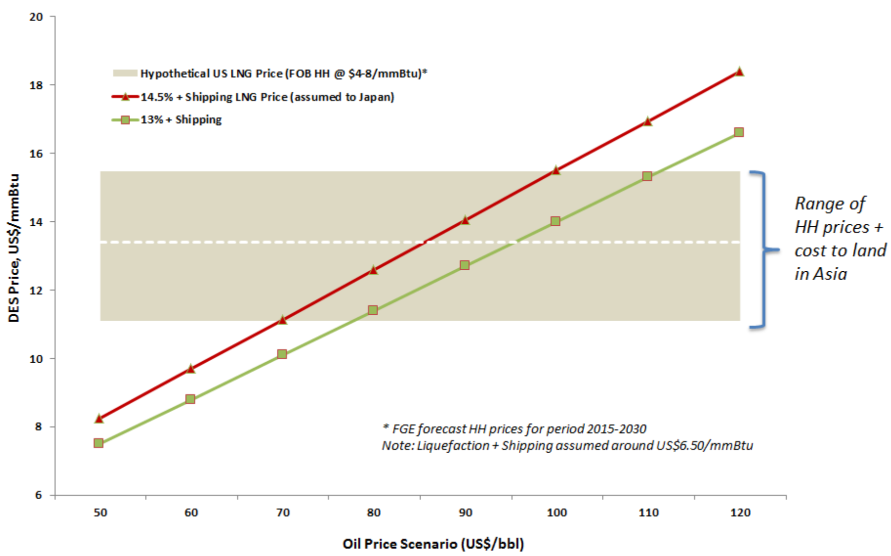
While U.S. gas supply is plentiful and low-priced, the greatest advantage U.S.-based LNG exports have over Canadian exports revolves around the cost structure. The majority of proposed export facilities already have a large portion of the infrastructure in place (tanks, jetties, land, etc.) because they were originally built as import facilities. The main capital cost will be for constructing liquefaction trains that will be needed to export the gas as LNG. In addition, the United States has an extensive gas processing and pipeline system that will deliver gas straight from the grid to the liquefaction plant, thereby avoiding the high costs of building gas pipelines that Canadian projects will incur. In the United States, gas is essentially bought from a big interconnected swimming pool, whereas in Canada it is bought from small lap pools that require significant investment in pipeline capacity to bring that gas to market.

While the United States does beat greenfield Canadian projects on the cost front, it does have its disadvantages. Proposed LNG exports from the United States have become highly political during recent months as the number of proposed export projects grows and business groups such as America's Energy Advantage that benefit from low gas prices have become more vocal about their concerns. How many non-FTA export licenses will be granted is still to be determined, but FGE believes that the United States will be exporting at least 30 mmt of LNG by 2020. However, even if all projects receive export permits, they will not all be built in the discussed time frames. The world simply does not need that amount of LNG nor does the industry have the necessary manpower to construct all these projects. In addition, drawing gas off the domestic grid means that U.S. developers can bypass costly upstream development costs, but this approach does carry one unquestionable disadvantage: variable gas-quality provisions. This can be an issue for some Asian buyers who need richer LNG streams. Finally, the location of most proposed export facilities on the U.S. Gulf Coast and the possibility of revocation of export licenses gives Asian buyers a cause for concern, although revocation of licenses is also a slight risk for Canadian projects. Asian buyers have consistently expressed worries that the U.S. Congress will revoke export licenses in times of high prices and keep the gas for the domestic market. FGE believes that the likelihood of this happening for a sustained period is very low, particularly given the United States' commitment to the WTO.

Hub Pricing vs. Oil Indexation

Given the cost structure of Canadian and U.S. projects, it is very likely that Canadian-sourced LNG will need to be largely, if not fully, linked to oil while U.S. LNG exports will be linked to Henry Hub. It is certainly possible that Canadian-sourced LNG will be a hybrid of oil- and hub-related pricing. What ultimately matters, however, is the absolute price rather than the index to which the price is linked. Yet, even if buyers index their LNG purchases to Hub prices, does this mean guaranteed lower costs? **Figure 10** illustrates that direct purchases of LNG from the United States do offer savings at high oil prices but provide only marginal savings at prices in the $70–$80 per barrel of oil (bbl) range.

Figure 10 *U.S.-sourced LNG vs. traditional Asian oil-linked formula*



Source: FGE.

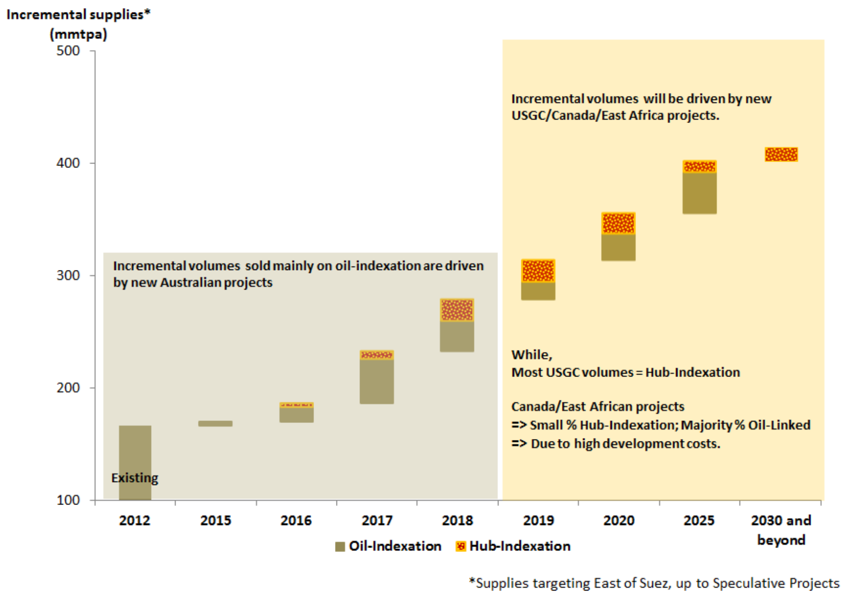
In this analysis, FGE assumed Henry Hub prices of $4–$8 per mmBtu and added a 15% premium as well as the cost of transportation and shipping ($6.50 per mmBtu) to come up with a price range of LNG delivered to Asia. We then weighed that figure against possible delivered prices of LNG from a project in the East of Suez region shipped to Japan at a slope of 0.145 (84% crude oil linkage) and 0.130 (76% crude oil linkage). These slopes are representative of today's long and mid-term market. As one can see, under today's oil price of around $100 per bbl and Henry Hub price of $3.50 per mmBtu, LNG sourced from the United States yields significant savings. However, Henry Hub is at extremely low prices, whereas oil is at relatively high prices, and these current price differentials are unlikely to continue for an extended period. One can easily see a world where the long-term oil price settles into an $80–$100 per bbl range due to declining oil demand in the United States as Corporate Average Fuel Economy (CAFE) standards take effect, as well as due to a surge in non-OPEC supply from tight oil. In addition, it is highly likely that long-term Henry Hub prices settle into a $4–$6 per mmBtu range as uneconomic wells remain shut until prices rise, more gas is consumed in the power and industrial sectors, and increased environmental regulations add to the cost structure. Under these scenarios, the price savings become marginal and FGE forecasts that the differential between the delivered Asian LNG price and Henry Hub will shrink to around $6 per mmBtu by 2020 from its current level of $15 per mmBtu.

It should be noted that absolute price is not the only factor in lifting LNG from the United States. Having a different linkage to oil does offer Asian buyers price as well as supply diversification. In addition, U.S. volumes can be lifted or not lifted depending on the needs of the buyers. Lifting U.S. volumes offers Asian buyers more flexibility than what is offered by traditional LNG projects in the East that have strict destination controls. This flexibility is valued by certain buyers, particularly those with seasonal markets, such as Korea, where demand is over twice as high in the winter as in the summer.

Oil Indexation to Remain a Mainstay in Asian LNG Contracts

High project costs, coupled with long-term LNG contracts that are currently in force, ensure that Asian LNG pricing will remain predominantly linked to oil for the foreseeable future. As illustrated in **Figure 11**, currently there is around 160 mmt of long-term LNG supply linked to oil. Over the next few years, oil-linked volumes will grow as Australian projects come online.

Figure 11 *Pacific region to stay mostly oil-linked*



Source: FGE.

If we look at proposed projects coming out of the United States, Canada, and East Africa, we will begin to see a larger influence of Henry Hub indexation by the end of this decade. However, the possible Hub indexation will still be relatively small, and there is no guarantee that all U.S. exports will be sold on a Hub basis. A large portion of U.S. LNG exports will be lifted by aggregators such as BG Group who will sell on an oil-linked basis; it will primarily be end-users such as India's GAIL and Korea's KOGAS who will potentially benefit from a direct Henry Hub linkage. While U.S. exports could be equivalent to 15% of Asian demand in 2025 (around 50 mmt), it is by no means certain that all the volumes will go to Asia. South America and Europe are likely to be an attractive destination for U.S. exports, and FGE believes that these regions are likely to account for 50% of U.S. LNG exports by the middle of the next decade. Finally, the higher cost structure of projects in Canada and new frontiers such as East Africa ensure that oil-linked pricing will remain a mainstay, given that these projects need this type of linkage to justify multi-billion dollar investments.

Concluding Remarks

While many buyers now seek hub-related pricing, some are under the impression that this guarantees lower prices. FGE believes that the impact of North American LNG exports on Asian prices will be marginal. Canadian projects will be primarily linked to oil at levels similar to existing Asian supply contracts to justify their greenfield costs. U.S. LNG will come to the market, but not at the level of the current proposed plans because price differentials between Henry Hub–linked and oil-linked contracts are expected to shrink in the coming years. However, Asian buyers will still look to add U.S. LNG to their portfolios as a price diversification and supply security strategy. In addition, U.S. LNG offers greater flexibility as well as a negotiating tool when dealing with traditional exporters in the East. North American LNG projects present another supply option, and project sponsors in Canada and the United States need to be aware that sophisticated Asian buyers may be simply using some of these projects as a price marker to negotiate what those same buyers may deem to be more credible projects in other parts of the world. Therefore, it is critical that sponsors gain both the participation of reputable international players and the support of the government to ensure a project's success. LNG is a capital-intensive industry, and supportive host governments and experienced project sponsors are the keys to successful development.