ABSTRACT

North American natural gas fundamentals and LNG exports confront the LNG industry with disruptive changes that create considerable uncertainties, risks, and opportunities for LNG buyers, sellers, traders, investors, and lenders. I will analyze the impact and implications of North American natural gas fundamentals on North American LNG exports and global LNG markets and transactions.

I will first provide a critical expert evaluation of the most impactful North American fundamental drivers of shale gas production and demand growth:

- The scalability, sustainability, and cost of shale gas production
- Natural gas demand growth for electric generation, industrial production, and transportation
- The upward price pressure of indigenous demand growth combined with LNG exports and the ability of shale production to mitigate those pressures and sustain low prices

I will next analyze the disruptive impacts of North American LNG exports on Pacific and Atlantic Basin LNG balances, prices, and 'shale spreads' over the mid-term, including:

- The competitive impact on competing (Australian) supply projects, global and regional LNG supply-demand balances, LNG market liquidity, and LNG prices
- The consequent magnitude of 'shale spread' tightening in the Pacific and Atlantic Basins — and the ability of tightening spreads to sustain North American LNG exports

Finally, I will draw conclusions regarding the implications for LNG investments, contracts, flexibility, and trading.

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I. OBJECTIVES

This paper presents an initial analysis prepared by Christopher Goncalves as preparatory material for his forthcoming presentation at LNG 17 in Houston in April, 2013. Due to the highly dynamic nature of the topic and in light of current US policy deliberations regarding LNG exports, the final presentation may differ substantially from the initial material provided in this paper.

The paper analyzes the impact and implications of North American natural gas fundamentals on North American LNG exports and global LNG markets and transactions.

The paper first provides a critical expert evaluation of the most impactful North American fundamental drivers of shale gas production and demand growth:

- The scalability, sustainability, and cost of shale gas production.
- Natural gas demand growth for electric generation, industrial production, and transportation.
- The upward price pressure of indigenous demand growth combined with LNG exports and the ability of shale production to mitigate those pressures and sustain low prices.

Next, this analysis is used to assess the disruptive impacts of North American LNG exports on Pacific and Atlantic Basin LNG balances and prices over the mid-term, including: the competitive impact on competing (Australian) supply projects, global and regional LNG supply-demand balances, LNG market liquidity, and LNG prices. Finally, it examines the consequent magnitude of tightening price differentials or “shale spreads” in the Pacific and Atlantic Basins — and the ability of tightening spreads to sustain North American LNG exports.

II. INTRODUCTION AND BACKGROUND

North American natural gas fundamentals and LNG exports confront the LNG industry with disruptive changes that create considerable uncertainties, risks, and opportunities for LNG buyers, sellers, traders, investors, and lenders. In North America, the LNG liquefaction investment and export thesis has been underpinned by the emergence of substantial and sustained shale spreads between low US natural gas prices — driven by increasingly abundant and low cost shale gas — and higher global LNG and natural gas prices that are fully indexed or partially benchmarked to oil in Asia and Europe, respectively.

Over the last four years, these shale spreads have grown to substantial levels. As shale production in North America boomed and U.S. natural gas prices collapsed, LNG prices remained more robust in Asia due to rising oil prices and historic oil-indexation practices that have dominated LNG and gas sales in Asian markets (even during periods when supply was abundant and demand was soft). As a result, Pacific shale spreads increased to levels ranging from $4 to $8 per MMBtu in 2009 and 2010. In Europe, however, the

1 Mr. Goncalves has led global gas and LNG advisory teams at two leading consulting firms. He has negotiated commercial terms and pricing for LNG and natural gas agreements, provided independent market and commercial due diligence for financings and investments, and delivered expert testimony for international commercial and investment disputes. He has also directed market analysis and forecasting, trading and diversion economic analysis, and commercial strategy. Mr. Goncalves holds an M.A. in International Affairs and Economics from the Johns Hopkins School of Advanced International Studies (SAIS) and a B.A. in International Relations from Brown University.

2 The opinions expressed in this report are those of the individual author and do not represent the opinions of BRG or its other employees and affiliates. The information provided is not intended to and does not render legal, accounting, tax, or other professional advice or services, and no client relationship is established with BRG by making any information available in this presentation. None of the information contained herein should be used as a substitute for consultation with competent advisors.

3 The terms “shale spread,” “Pacific shale spread,” and “Atlantic shale spread” were first coined by Mr. Goncalves at a CWC Conference in November, 2011.

4 Pacific shale spreads are measured here as the difference between HH prices in the US and average Japanese LNG import prices (customs prices).
Atlantic shale spreads\textsuperscript{5} were much lower, ranging from $0 to $4 per MMBtu because European LNG import prices have a higher linkage to spot market prices, which have been more responsive to LNG and natural gas supply liquidity (such as during the global gas glut of 2009 and 2010).

Compared to the oil-indexed markets of Asia, European prices were much more responsive to the global oversupply or “glut” that was wrought by a “perfect storm” of shale production, global economic recession, and vast volumes of Qatari LNG previously developed to serve North America and other markets no longer hungry for the product. Europe became a “sink” market for LNG supply that was neither needed in the shale abundant and low-priced markets or North America nor in the high-priced but saturated markets of Asia. As a result, European natural gas and LNG prices collapsed to levels that were substantially below oil price parity. In this environment, the price collapse was significantly aided by the rapidly increasing depth of European spot markets in the UK and Northwest Europe.

In 2011 and 2012, shale spreads doubled in magnitude. The combination of resumed economic growth and the Japanese nuclear shutdows of mid-2011 that were ordered following the tragic tsunami and nuclear disaster at TEPCO’s Fukushima facility in March of 2011, enabled Japanese and Asian buyers to mop up most of the surplus LNG and tighten global LNG markets. Asian LNG prices increased rapidly and steadily even as North American shale production surged and prices bottomed. The Pacific shale spreads climbed to levels over $15. To a lesser extent, Atlantic shale spreads followed suit, climbing from $4 to almost $8.

These trends are illustrated in Figure 1 below.

These wide shale spreads reflect the abundance of low cost shale resources in North America, on the one hand, and — in the aftermath of Fukushima — the emergence of global LNG supply constraints, on the other. The long-term sustainability of wide shale spreads thus reflects the sustainability of shale production and tight global LNG markets.

LNG exporters and LNG traders are not the only parties looking to profit from shale spreads. Asian and European LNG buyers and traders are also eager to obtain new sources of LNG that are tied to North American Henry Hub (“HH”) pricing as opposed to oil indices such as JCC and Brent.

\textsuperscript{5} Atlantic shale spreads are measured here as the difference between HH prices in the US and NBP prices in the UK.
These interests will compete with North American domestic buyers for access to low cost shale (and LNG). North American industrial facilities in natural gas intensive sectors such as petrochemicals, chemicals, metals, and others have discovered a new source of competitive advantage in global trade and are already investing heavily in both greenfield and brownfield facilities. Additionally, transportation fleet and maritime operators dependent on expensive diesel and bunker fuels are eager to switch to LNGV, NGV, and other applications.

As a result, a major policy debate has emerged in Washington, DC regarding whether US LNG exports serve the public interest—a debate that is sure to continue throughout 2013 and perhaps beyond. On the one hand, natural gas producers and LNG exporters argue for a liberal policy of free trade in LNG where exports are unrestricted, citing the benefits to energy production, energy security at home and abroad, and various geo-strategic benefits. On the other hand, various industrial, environmental, and gas consumer groups argue for caution and various form of restriction or restraint on LNG exports to protect against their concerns regarding higher natural gas prices, reduced competitive advantage, and environmental harm.

III. NORTH AMERICAN LNG EXPORT DRIVERS

The shale spreads underpinning the North American LNG export ambitions, in turn, are anchored by the abundance and long-term sustainability of low cost regional shale production.

US shale production levels continued to swell from levels just over 5 Bcfd (below one-tenth of market) to well over 20 Bcfd in 2011 and 2012 (over one-third of market). In turn, natural gas prices plummeted from levels that spiked above $10 in early 2008 to levels consistently below $5 since 2009 and well below $5 since mid-2011, reaching lows of $2 in early 2012.

As shale production boomed, storage inventories swelled and pricing softened. In response, conventional drilling activity declined precipitously in 2009 and has continued to tumble since. Shale drilling activity continued to increase steadily through mid-2010, but then rig counts in the higher cost “dry” shale plays—which contain little or no natural gas liquids (“NGL”) content—began to decline. As prices hit bottom in late 2011 and early 2012, low-cost “wet” shale rig counts began to fall as well, as drillers pulled back on activity and capped numerous completed wells that had not yet been fracked and connected to pipelines and processing plants for production.

This trend was particularly strong in the Marcellus play, where new pipeline and NGL processing infrastructure is needed to accommodate growing volumes of production, much of which is rich in NGLs. Many of the producers relocated their drilling activity to the prolific Eagle Ford play in Southern Texas, which is also rich in NGLs but closer to critical processing infrastructure.

By early 2013, total rig counts had fallen to extremely low levels, although actual natural gas production continued to increase due to higher than expected initial production rates (IP rates) and lower than expected decline rates for many producing shale wells that surprised the industry.

These trends are illustrated in Figure 2 below.
As a result of the drilling pullbacks, shale production growth has begun to gradually decelerate over the last half year. Still, natural gas storage inventories have remained very high. Consequently, prices have rebounded from the $2s into the $3s, but still remain very low by recent historical standards.

Logical questions regarding how much longer shale production can grow with reduced drilling activity are answered by the critical fact that several thousands of drilled and completed shale wells have been capped and held for fracking and initial production at a later time. The production community is eager for signals that increased drilling and additional production make commercial sense when one or more of the following occur:

- Production begins to decline as the shale decline rates from existing wells kick in;
- Increased gas demand stems from the “industrial renaissance” in gas-intensive industries;
- LNG exports are authorized, unrestricted, and begin to flow; and
- Ultimately, natural gas storage inventories decline and prices increase.

In the shorter term, the backlog of storage inventories, capped wells, and low cost shale appears to be adequate to keep a lid on prices under virtually any natural gas demand and LNG export scenario.

But looking ahead into the coming decades, a critical question is: how much new demand – both domestic and foreign — can North American shale production sustain at low prices? Could the combination of continued substantial declines in conventional production and redoubled demand from power generation, industrial facilities, and also LNG exports begin to test the shale revolution?

US gas consumption barely increased from 64 Bcfd in 2000 to 67 Bcfd in 2011, primarily due to increased reliance on natural gas in the power generation sector that offset declines in industrial production. Looking ahead to 2025, a more substantial increase of up to 9 Bcfd in power generation and industrial demand is projected by the US Energy Information Administration (“EIA”) and perhaps approximately 6 Bcfd (45 MMtpa) of LNG exports could begin to flow (as a mid-range estimate now common in the industry). This would yield a combined increase of 15 Bcfd, and increase total US demand to 82 Bcfd. With declining conventional production, the overall draw on shale production could reach 42 Bcfd or more – almost double current production levels and representing over 50% of an expanded future market. Stated on an annual basis, that would represent over 15 Tcf per year of shale production.

Recent EIA estimates of technically recoverable shale approximated 700 Tcf, including both “dry” and “wet” shale plays that are rich in NGL content. Recent shale output levels of 22 Bcfd equal about 8 Tcf per year.
meaning that the total shale resource represents over 90 years of shale production at current shale production levels.

However, as discussed above, shale production will need to double by 2025. Additionally, there are big economic differences between the “dry” and “wet” shale resources. Approximately 300 Tcf is located in NGL rich plays that tend to offer lower methane production costs due to the significant revenues available from NGLs. Not all of that gas will be economically recoverable, and not all of it will be as economic as the current production, which remains focused on the geological and logistical “sweet spots.”

Factors that will affect the future cost of this production include above all NGL prices and their continued linkage to high oil prices because the revenue from NGLs pays for much of the production investment and thus reduces the net cost of producing the dry gas or methane. Environmental regulations and the attendant compliance costs for flow-back water treatment and/or recycling and well casings and completion standards will play a big role as well. Production royalties and severance taxes, federal fiscal policy incentives for drilling (or their removal), and land lease rates will also have an impact. In our analysis, this implies a wide range of potential “average” net methane production costs from the nation’s NGL rich shale plays – from under $3 to over $6. (Production costs from “dry” shale plays are substantially higher due to the absence of valuable NGL revenue to offset total costs).

It seems logical to assume that production costs will be lower in the early years when drillers are able to focus on “sweet spot” production, NGL prices are firm, environmental compliance is relaxed, and tax and fiscal policies are favorable. Over time, there will be an increasing risk that each of these favorable features will become less favorable and so production costs will increase. This could be partially offset by continued efficiency gains from shale production, although efficiency gains have been so tremendous thus far that the industry may approach a limitation on future efficiency gains. Therefore, even in the most economic plays, production costs will need to increase as production necessarily ramps up to ever greater scales.

As shale production grows to the 42 Bcfd or 15 Tcf per year expected in the next decade, the 300 Tcf of NGL-rich shale plays will be drawn down to perhaps 150 to 200 Tcf (barring future discoveries). By 2025, therefore, perhaps only 10 to 15 years of NGL-rich, low cost shale reserves will remain in place at those future shale production levels – assuming all technically recoverable resources will also prove economically recoverable.

To the extent that indigenous natural gas demand or LNG export demand grows faster, the pressure on NGL-rich shale resources will be even greater. However, this risk is probably offset by the possibility of greater discoveries of NGL-rich shale resources.

IV. NORTH AMERICAN GAS MARKET IMPACTS

Much of the policy debate regarding LNG exports is focused on the domestic price impact that various future levels of LNG export “demand” will have on US gas prices – and thus the prized competitive advantage in energy input costs that US industries perceive at present.7

This debate has become somewhat circular and does not seem to yield any clear conclusion:

- Natural gas consumers have argued, mostly without hard analysis, that the upward impact on natural gas prices from large or rapidly growing LNG exports could be substantial – on the order of over $1 per MMBtu.

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- LNG export terminal sponsors and independent producers, in response, have issued a small number of studies arguing that in all scenarios for LNG export volumes—typically ranging from a low of 3 Bcfd (22 MMtpa) to highs of 12 Bcfd (90 MMtpa) or more—the price impacts will be small (well below $1) and probably short-lived (recovering within a period of months or years). Due to the abundance of low cost shale resources, these studies consistently posit very flat shale production cost curves and/or the ability of nimble shale producers to anticipate future demand growth and respond swiftly by uncapping wells and/or mounting new drilling campaigns.

- Most recently, a DOE sponsored study commissioned to advise the current policy deliberations regarding LNG exports has essentially argued that LNG price export impacts will be limited (never greater than $1.11 per MMBtu) even in scenarios where the US exports up to 12 Bcfd (90 MMtpa). The study assumes that US exports will not rise above that level, but acknowledges that unconstrained exports could be higher.

Although most of the US policy debate centers on the impacts of LNG exports on US gas prices, the critical issue to analyze is not the impact on US gas prices in a vacuum, but rather the combined international impact on “shale spreads.” Most analysts agree that the impacts on US prices are likely to be limited and/or short lived, due to the abundance of potential low-cost shale production. Much more important and more impactful will be what North American LNG exports will mean for global LNG prices, especially in Asia, and therefore for the “shale spread.” These shale spreads are the critical driver of North America’s current competitive advantage in energy input costs.

V. GLOBAL LNG MARKET IMPLICATIONS

The reason understanding the impact of LNG exports in North America is so confusing is because it depends much more on global market dynamics and impacts than it does on the North American market itself. A freely traded and highly liquid natural gas market like North America is relatively easy to understand; whereas the highly fragmented and partially oil-indexed global LNG market is much more opaque. As a result, LNG markets are not as easily understood or analyzed as the North American market.

US natural gas price impacts from LNG exports—small, medium, or large—are likely to be measured in cents per MMBtu due to the abundance of low cost shale for at least several decades to come. By contrast, the impact in global LNG markets could amount to several dollars per MMBtu due to the very high levels of global prices and the distances they could fall should enhanced supply liquidity alter the terms of trade—ranging from reduced oil indexation “slopes” to perhaps reduced reliance on oil indexation as the preferred LNG pricing methodology.

In other words, even if US gas prices respond very little to large volumes of North American LNG exports, global LNG prices and shale spreads could respond quite substantially. The timing and magnitude of “shale spread” decreases, in turn, could impact the level of North American liquefaction development and ultimate LNG export volumes. For example, the following scenarios for “shale spread” response could occur:

- If the impact of initial North American LNG exports on Asian LNG prices is swift and substantial, then the shale spreads underpinning the LNG exports will be weakened and the commercial and financial risks for new liquefaction investments could quickly become untenable. As a result, the actual capacity built and volumes exported could be quickly constrained. Further, if the LNG sale-purchase agreements include a high degree of flexibility for offtake volumes, then the export volumes from existing terminals could decline.

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8 “Macroeconomic Impacts of LNG Exports from the United States”, Figure 29, page 51 shows the impact of exports on US natural gas prices in all scenarios.
9 Ibid., Page 3.
10 Ibid., Page 6.
• If, on the other hand, North American LNG exports do not have a substantial impact on Asian LNG prices, initially or ever, then the shale spreads driving North American LNG exports should be sustained and will support liquefaction investments and contract exports over a sustained period of time.

In other words, with US prices expected to be relatively stable with or without North American LNG exports, the critical issue for shale spreads and sustained North American LNG terminal investments and export volumes will be how much and how fast Asian and European LNG prices respond to the volume of North America LNG exports.

Over the long-term LNG prices should respond and equilibrate toward North American prices (adjusted for liquefaction costs and transportation differentials), but this could take a long time. Several factors such as the historical LNG business culture, entrenched-oil indexation practices, and established long-term contracts could act to retard price equilibration for quite some time.

The window of opportunity for North American LNG exports is wide open, but it is not clear for how long that will last and how quickly the window will be shut.

For an example of the impacts, the global gas glut of late 2008 to early 2010 is instructive. During this period, spot prices throughout North America, Northwest Europe, and Asia collapsed in response to the glut. Nevertheless, as general matter, the existing long-term contracts remained in effect and suppliers stood by oil-indexation practices in Asia and some other markets. As a result, LNG buyers around the world concentrated their purchases on spot purchases and/or short-term supplies tied to spot. Wherever possible, buyers sought to reduce long-term contract volume commitments and or leverage contract flexibility to reduce contract purchases and increase spot purchases.

One key difference between the recent gas glut and any potential future supply shock caused by North American LNG is that in the historical period there was no new market price introduced for new LNG supply sources. In the future, North American LNG exports will introduce HH priced sourced supplies into the market adding HH as a major global supply index alongside other global spot prices, NBP and JKM, and the oil indices Brent and JCC. Notably, the depth and liquidity of HH exceeds these global gas indices by a wide margin, even though the HH market liquidity is only a fraction of major oil indices.¹¹

If global LNG markets are generally balanced or supply-constrained and North American LNG exports are limited, then they will be a marginal source of global supply that is unlikely to have a substantial impact on LNG prices. If, however, global markets enter a period of surplus and North American LNG exports are more substantial, then the LNG price impact could be significant.

Although the recent gas glut was structural — caused by a wave of capacity over-building, primarily in Qatar, that failed to anticipate the shale revolution and the global economic recession — the situation was effectively resolved by the comprehensive Japanese nuclear shutdowns in mid-2011.¹² Once it became clear that Japan’s nuclear plants would be out of services for a sustained period, spot prices began to realign with oil-indexed prices and the “buyer’s market” began to unravel.

This historical example raises several critical questions regarding the prospect of large-scale US LNG exports in the coming decade:


¹² The Japanese nuclear shutdowns were ordered primarily to address public safety concerns in the aftermath of the Fukushima tragedy in March, 2011.
• In light of other LNG supply and demand trends, to what extent will North American LNG exports fundamentally or structurally alter the global supply-demand balance and tip the terms of trade in favor of buyers?

• To what extent will the introduction of a new HH-indexed source of LNG supply and new LNG cost structure impact the terms of trade?

• In light of these features, to what extent will the North American LNG exports empower buyers to fundamentally restructure the way they purchase LNG or will they be limited (or limit themselves) to making more moderate or marginal pricing adjustments?

For purposes of this initial paper, a few key observations are appropriate now. Final conclusions will be deferred until the LNG 17 presentation in Houston next April.

Looking out over the coming decade or two, North American LNG exports may be the “next big thing” but they will not be the only big thing. A handful of major supply and demand drivers will directly impact the global supply-demand balance, supply liquidity, and thus also the outlook for LNG prices. These are listed in Figure 3 below.

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<th>Supply Drivers &amp; Disruptions</th>
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<td>Regas Terminals for New Markets</td>
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<td>Australian Production Delays</td>
<td>Chinese Shale Production</td>
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<td>East Africa and Israeli LNG</td>
<td>Japanese Nuclear Policy</td>
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Figure 3: LNG Supply & Demand Drivers

In addition to uncertain levels of North American LNG production, the backlog of Australian LNG terminal projects already under various stages of construction suggests an additional 12 to 14 Bcfd (90 to 105 MMtpa) of production capacity by the next decade. However, it stands to reason that after years of substantial delay and cost overruns, some of the less economic Australian projects are vulnerable to fresh competition from North American LNG supplies. At any given level of market demand, the greater the level of North American LNG development the greater the risk of Australian project failure, cancellation, or delay. In our recent analysis, we have found that every 3 Bcfd (22 MMtpa) of US LNG export capacity added can harm approximately 1 to 1.5 Bcfd (7 to 11 MMtpa) of Australian capacity.13

Any such Australian casualties are likely to be offset by new production from East Africa and/or the Eastern Mediterranean. In particular, the Mozambique LNG and Israeli Tamar LNG projects could add at least 1.6 Bcfd (12 MMtpa) of new capacity by mid-2020, if not more.

Therefore, on balance, the North American LNG supply does represent truly incremental supply above and beyond these other sources. Assuming an approximate North American LNG addition of 6 Bcfd (45 MMtpa), the total backlog of supply additions, net of casualties, could range from 18 to 20 Bcfd (135 to 150 MMtpa).

On the demand side, our analysis of new regasification projects throughout the emerging markets of Southeast Asia, Latin America, and Eastern Europe could add perhaps 6 to 9 Bcfd (45 to 67 MMtpa) of new demand. In Eastern Asia, the big stories are Japan and China, which could add up to 4 Bcfd (30 MMtpa) and 8 Bcfd (60 MMtpa) of new consumption respectively. However, almost all of the new Japanese consumption is subject to uncertainty regarding Japanese nuclear policy; a substantial relaxation of rules regarding the restoration of service at many nuclear plants could substantially erode or even reverse Japanese demand.

13 This does not reflect a rigid linear relationship, but rather a detailed project by project assessment.
growth. For China, almost all of the incremental demand for LNG could be contested by rapid development of shale gas resources by early in the next decade.

Considering all these factors, the range of future demand from these major consuming markets could range from as little as 12 Bcfd (90 MMtpa) to as much as 21 Bcfd (157 MMtpa).

Considering supply and demand together, these results could imply a wide range of outcomes. On the high demand side, these results could help sustain the current, supply-constrained LNG markets of the current period and on the low side supply could substantially overshoot demand, yielding a new period of structural oversupply. These scenarios are presented in the Figure 4 below:

Figure 4: LNG Supply & Demand Scenarios

Interestingly, in the high supply and demand scenario the 8 Bcfd (60 MMtpa) amount of potential oversupply is only slightly greater than a 6 to 8 Bcfd (45 to 60 MMtpa) mid-range estimate for North American LNG output. Stated differently, due to a wide variety of uncertainties about future LNG demand (which is always hard to predict), it is not clear whether and to what extent the incremental LNG from North America is actually needed. The need for this LNG could range from none to almost all of the estimated mid-range exports by the middle of the next decade.

But even if North American LNG is not truly “needed” from a consumption volume perspective, it is certainly “wanted” from a price perspective. After the tremendous run-up in LNG prices that resulted from the Japanese nuclear shutdowns, the LNG-dependent Japanese economy has been battered by high LNG and oil prices. Other Asian economies have also been constrained by high fuel input costs for oil and oil-indexed LNG. Despite numerous other competitive advantages, high fuel prices have begun to suck wind from some Asian economic sails.

As Japan’s Minister of Economy, Trade, and Industry, Yukio Edano put it delicately on September 19, 2012,

“For the Japanese government and business, securing LNG at a low cost poses a major challenge...with the paradigm shift due to full-fledged production of shale gas, oil-linked indexing is starting to be less reasonable.”

These market insights are critically important to assessing the global market impact of North American LNG. It is certainly possible, if not probable, that the demand for North American LNG will be caused more by high oil-indexed LNG prices in Asia than by physical demand for additional volumes of LNG (due to slow global demand growth, Chinese shale production, Japanese nuclear policy, and other factors). If this remains the case, then significant adjustments will be required. The following alternatives stand out:
On the supply side, Australian projects could fail and/or the other new supplies in East Africa and the East Mediterranean could be displaced or deferred, although this would probably only make room for some of the potential North American supply.

With respect to prices, buyers could require more competitive oil slopes or even new gas-referenced indexation to compete with HH-based supplies from North America. For example, in a recent interview an official from Osaka Gas ("OG") outlined the utility’s intention switch from full reliance on oil-indexed LNG contracts to "introduce alternative pricing benchmarks" based on natural gas prices.14

One or both of these sorts of adjustments could occur if LNG demand does not grow to the levels hoped and expected by the industry — with LNG demand widely expected to more than double to levels over 60 Bcfd (250 MMtpa) during the next dozen years. If supply is robust and demand is not, the potential for a substantial alteration of global pricing practices should not be taken lightly.

Between 2015 and 2025, approximately 8 Bcfd (60 MMtpa) or 52% of LNG SPAs for the premium markets of Japan, Korea, and Taiwan will expire, creating a substantial commercial opportunity for buyers to end old, oil-indexed contracts and drop existing suppliers in favor of new suppliers who are willing and able to price LNG on a gas or hub-indexed basis. To the extent that new North American LNG contracts also include more favorable volume flexibility provisions than traditional Asian LNG contracts, the buyer incentive to pursue new North American LNG sources would be enhanced.

But this can only happen if buyers are encouraged and empowered by real supply alternatives and that will only occur if LNG demand falls short of industry hopes and expectations. If demand is strong and market fundamentals are less favorable to buyers during this period, then they may be forced to settle for more moderate adjustments by negotiating lower slopes to oil, better S-curves, and so forth. In a more supply constrained environment, the price arguments of Pacific Basin LNG suppliers will prevail.

It is not only the incumbent Asia Pacific region suppliers who will defend oil-indexation. Across the Pacific, Chevron’s CEO, John Watson, emphasized the importance of oil-indexation to justify the Canadian LNG investments, stating that "pricing is going to need to be something close to oil parity, or the projects won’t get built."15

Finally, the magnitude of price adjustments in Asia will determine how wide and how long the window of opportunity for North American LNG exporters stays open. With North American prices only likely to move marginally upward by $1 over the coming years, and the incremental price impacts from LNG exports probably constrained to under $1, it seems unlikely that prices will climb above $5 to $6 over the coming decade or two. Assuming $4 to $5 for additional liquefaction, LNG shipping, and trading/margin costs, a delivered price to Asia should remain at or below $10 per MMBtu.

With Asian LNG prices having recently sustained levels well above $15, the critical question is whether global trade fundamentals will enable buyers to drive prices down to those levels — eventually or ever at all. The closer Pacific shale spreads get to a natural minimum of $4 to $5, the riskier North American LNG export investments and trade will appear. If and when this happens, the window of opportunity for North American LNG exporters will begin to close.

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