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The Re-emergence of Convergence

The Next Decade for the Global Gas Markets

Manas Satapathy, Nuri Demirdoven, Al Escher, and Muqsit Ashraf, are Vice-Presidents of Schlumberger Business Consulting (SBC), Houston, United States.

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Background

Shale gas has transformed the North American natural gas market, but its potential to influence global markets is often called into question. Our analyses predict greater international flows of gas over the next decade as a result of surging United States (U.S.) supply. Eventually, North American gas volumes will be sufficient to influence and possibly break the world's three-way, regional gas-market model: oil-linked Asia; gas-on-gas North America; and Europe, a hybrid of the two. In this scenario, the approximate gas-price ratio of 1:2:4 for North America, Europe, and Asia will not hold beyond the temporary shocks. We deem these geographically distinct markets "converged" if differences in gas prices between markets can be fully explained by transportation costs and, where applicable, liquefaction and regasification costs.

In the 10 years leading up to 2008, before North American shale gas took off, natural gas markets were heading towards global convergence at a higher price. U.S. natural gas reserves were falling, and the country was rapidly building import capacity. Europe's mature gas fields were in decline, and Russian oil-price indexed gas supplies were increasingly influential, threatening nascent European trading hubs. At the same time, surging demand in import-dependent Asia was generating increased competition for limited liquefied natural gas (LNG) supplies, forcing prices up. Although gas markets were not physically connected, planned infrastructure suggested convergence was coming – there were long-distance pipeline projects to supply Europe and China, as well as massive investment in LNG export capacity worldwide. U.S. spot prices jumped into line with gas prices in Europe and Asia.

The unconventional gas boom in North America broke any such convergence. In a few short years, the U.S. became very, very long in gas — long enough to become a large exporter. Prices responded by falling to less than one-third of their 2008 peak (Canadian gas prices experienced a similar decline). North American gas prices had decoupled from those of the rest of the world, on the downside.

One question now is whether North American gas can still have an impact globally. The answer comes down to volume. In the years leading up to 2025, contributions to supply from shale-gas deposits outside North America will be limited. And although rising international LNG supply will significantly boost global gas supplies (analysed later in this article), incremental volumes will seldom share the cost advantage of North American gas. So the root question becomes how much North American gas could seek global markets, relative to the size, and residual need, of those markets. If the volume is small, the *status quo* — three distinctly priced regional gas markets — is unlikely to be disrupted in the long term; if it is large, it will be very difficult to maintain.

In early 2015, we are witnessing a different type of – artificial – convergence, caused by declines in the prices of oil-linked LNG. This phenomenon is quite distinct from the drop in North American gas prices, which resulted from an increase in the availability of gas. Indeed, the fall in oil-linked gas prices should reverse when oil prices recover. We believe the current downturn in oil prices could only accelerate global gas-price convergence if price weakness were to persist for several years, which, at present, we consider unlikely.

Aim

The present article assesses the potential of LNG exports, especially from North America, to affect global supply and demand fundamentals. It also gauges the impact of the oil-price collapse on gas markets. In addition, we appraise the potential for North American gas volumes to change and possibly break the world's three-way, regional gas-market model (oil-linked Asia; gas-on-gas North America; and Europe, a hybrid of the two) over the long term. Ultimately, we seek to determine whether or not global natural gas markets continue to converge.

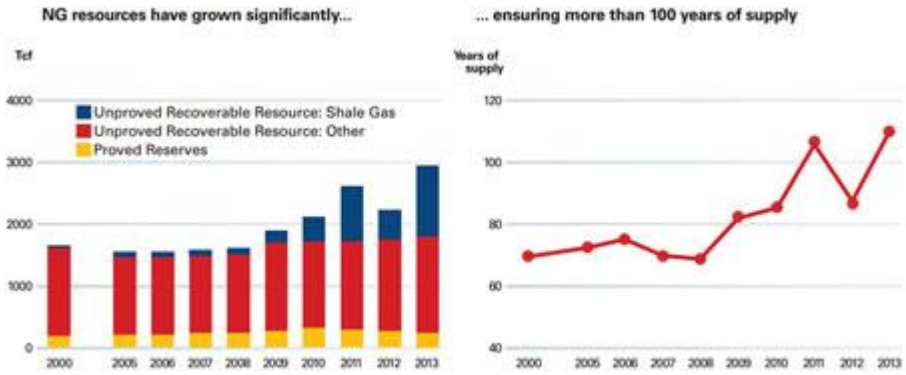
Methods

Using proprietary data from various internal and external sources, we were able to extrapolate US unconventional-gas supply and match it to demand. In addition to geological and subsurface factors, all relevant above-ground dynamics, such as infrastructure development and regulatory issues, were taken into account. Analysing sub-basin type curves, developing cost curves specific to each play and taking future technological improvements and working practices into account strengthened the methodology and results.

Results

Lasting Fortune of North American Gas

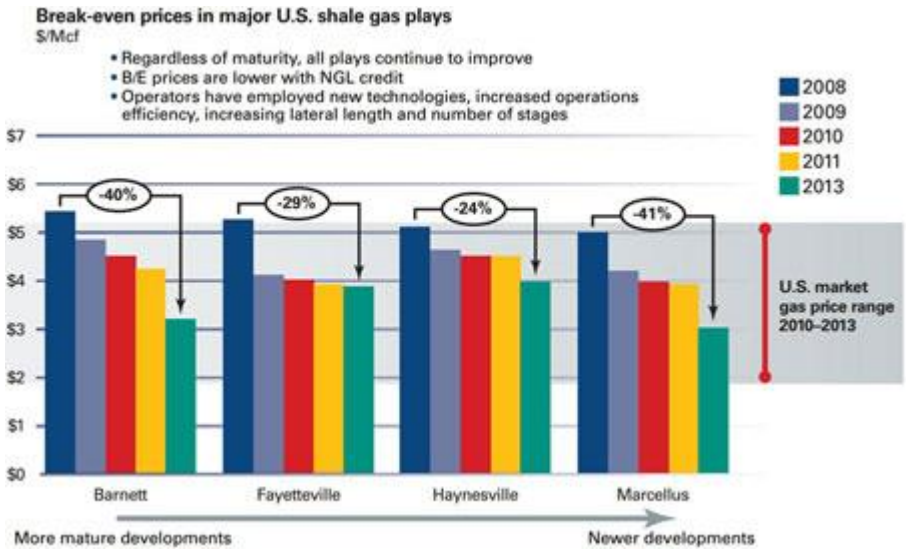
Figure 1: Unconventional revolution has left the U.S. with significantly larger gas reserves



Sources: EIA; SBC analysis

North American gas supply has become very large relative to local demand. Recoverable resources amount to more than 100 years of supply, and new technologies are bringing additional resources into play (see figure 1, above). Drilling and production efficiency have steadily increased as the industry has progressed along the learning curve. As a result, break-even costs have fallen by more than 40% in several important gas fields, and more plays are becoming economic (see figure 2, below). U.S. natural gas production has risen accordingly, reaching a record 25.7 trillion cubic feet (Tcf) in 2014, up by more than 25% since 2008. These production rates have been achieved with a fraction of the drilling fleet; in early 2014, the U.S. gas industry was operating with half as many gas-directed rigs as it was in 2012.

Figure 2: Improvement in technology and production efficiency is lowering B/E prices



Source: SBC analysis

It is difficult to see what could stop this gas from coming to market when needed. On the technical side, some subsurface experts claim the industry is rapidly exhausting sweet spots and core acreage, and is underestimating decline rates from unconventional wells. Our work indicates that improvements in technology and working practices will continue to expand the economically producible resource envelope, identifying new sweet spots across larger swathes of acreage and blurring the distinction between what the industry currently classifies as core and non-core acreage. In addition, there is now sufficient empirical evidence to rule out a disruptive negative impact on flow rates and ultimate recovery.

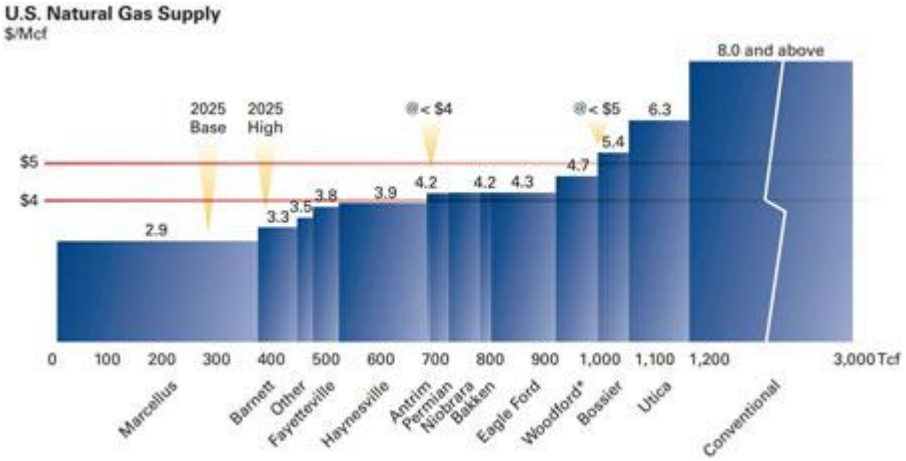
At the surface, a prolonged oil-price slump would have an impact on North American associated-gas production, but this could quickly be offset by diverting rigs to drill for gas (and rig-hire rates would also be likely to fall during an oil-price slump, making more gas economic to develop). Regulations could theoretically halt gas drilling, but the states regulate much of their oil and gas activity, and the current carbon-sensitive administration is supportive of gas production. Beyond this, the industry continues to have access to land, capital, infrastructure, and service capacity and remains capable of executing projects efficiently.

Meanwhile, the efficiency of North American gas production operations continues to improve. As the shale-gas industry matures more wells are being drilled per rig (i.e. rig efficiency is increasing with improved techniques such as pad drilling). In addition, wells are now being drilled in richer and higher-yield spots (new sweet spots are being identified), with higher initial production rates and estimated ultimate recoveries. The "dry gas" production equation is therefore only improving over time, as a result of advances in drilling and completion, and other areas of technology. Furthermore, as the quest for tight oil intensifies,

there has been an increase in associated-gas output, which now accounts for nearly a fifth of gas production in the contiguous U.S. Hence, North America is likely to experience further growth in shale-gas production capacity in the foreseeable future.

Going forward, at least 1,000 Tcf of U.S. gas (see figure 3, below) and approximately 500 Tcf of Canadian gas should be technically recoverable at a price of $5/million cubic feet (Mcf), even with existing technology, and the industry has the capital and talent to develop it and increase the recoverable total.

Figure 3: All domestic demand can be met ~$4/Mcf



Sources: IHS CERA; Hart; CSFB; MS; CIBC; SBC Analysis

Plenty of Gas to Go Around, and Then Some More

The pool of available gas is large, but how does it compare to current and anticipated demand? North American natural gas consumption amounted to about 30 Tcf (or quadrillion Btu) in 2014, accounting for over a quarter of total energy demand. Consumption is more or less equally divided between the power, residential and commercial, and industrial sectors. The substitution of coal by gas in the power sector is now an established pattern; in the past few years, about 15% of coal-fired generation has switched over to natural gas. However, there is a limit to how much coal-fired power can be supplanted by gas; lower coal prices and forthcoming environmental regulations will limit the growth of natural gas demand in the power sector to 10–12 Tcf a year by 2025. Meanwhile, industrial demand for natural gas has increased since its dip in 2009. Between then and 2013, industrial-sector demand for gas rose by 20% to 8 Tcf, mostly as a result of the considerable energy requirements of iron, steel, and bulk chemicals manufacturers. We expect this growth to continue, albeit at a slower pace, increasing by another ~1 Tcf by 2025. We do not expect natural gas to become a major transport fuel beyond certain niche compressed and liquefied applications because of long technology lifecycles and infrastructure barriers. In summary, gas use is already widespread in North America, so even healthy growth in the industrial and power sectors will not result in a sudden change in gas-demand growth.

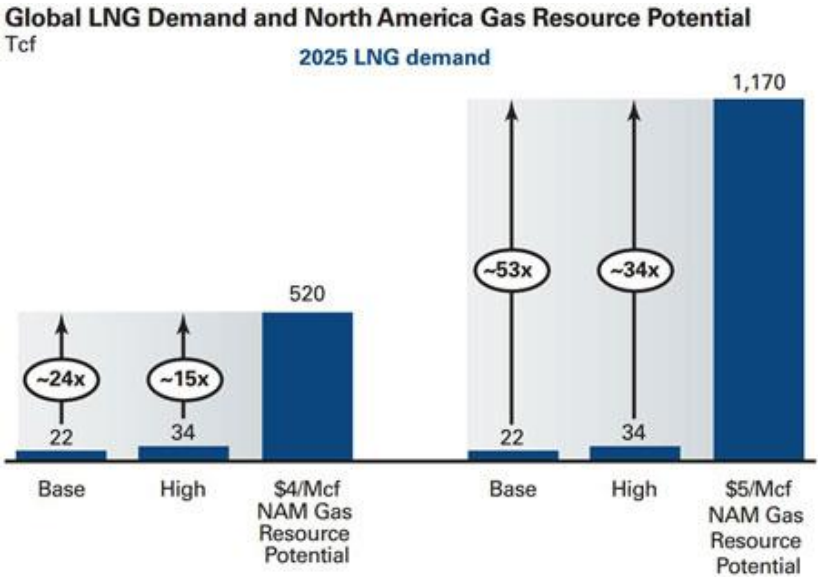
We expect North American demand for natural gas to be around 35 Tcf a year by 2025, amounting to a cumulative demand of just over 350 Tcf between 2014 and 2015. In comparison, around 1,500 Tcf of gas is available at or below a price of $5/Mcf, and 850 Tcf at or below a price of $4/Mcf. This suggests that more than 1,000 Tcf of cumulative gas supply through 2025 could be available for export after indigenous demand has been met. Supply could increase yet further as a result of natural gas liquids credits and associated gas and technology improvements. Even a small fraction of gas volumes that could theoretically be available for export would be sufficient to flood the LNG market. The supply curve suggests that this kind of volume could be exported without causing a significant increase in local gas prices. There could be temporary strains on the system and spikes in prices due to infrastructure bottlenecks and cold weather, such as those experienced in the 2013-2014 winter, but these would not significantly affect the economics of investments in gas consumption, particularly in LNG exports, which would bring gas to more lucrative markets.

North America's gas resources are huge, and can be brought to market quickly and flexibly. To meet North American demand, local gas production would have to grow at just above 1% annually between 2015 and 2025. If gas production were to grow at the recently observed >5% rate, total production through 2025 would be nearly 50 Tcf, or 15 Tcf more than demand. As noted above, most of the drilling fleet is not needed today to meet gas demand. So the rate of extraction for North American gas could be higher today and certainly much higher by 2025. In fact, if we were to return to the same number of gas-directed rigs that were in use in 2012, cumulative North American production would exceed demand by over 100 Tcf – without even considering technology- and workflow-related efficiency gains that could be reasonably expected. If sufficient liquefaction infrastructure were available, North America would be capable of exporting gas volumes of this magnitude. Given the potential for such a large excess of supply, it is also difficult to see North American gas prices settling significantly above $5/Mcf, barring the occasional spike, for a very long time. As a result, cheap feed gas should remain available for LNG export.

Henry Hub Going Global

Global annual demand for LNG, meanwhile, is currently 14 Tcf (a little over 10% of total gas consumption) and is projected to rise to 22 Tcf by 2025, with cumulative gas production in the 2015-2025 period expected to exceed 200 Tcf. Therefore, North American gas could meet over 100% of the expected increase in global LNG demand (see figure 4, below). Of course, the U.S. is not the only country that could meet this demand. Qatar already meets a quarter of global LNG demand. Australia is building seven new LNG projects, and its LNG production capacity will rival Qatar's by the end of the decade. Mozambique is planning to build LNG trains comparable in size to those in Qatar and Australia. Papua New Guinea has started LNG shipments in 2014. Other LNG exporters include Indonesia, Malaysia, Algeria, Russia, and Yemen. Global LNG capacity would amount to nearly 50 Tcf a year if all proposed projects were to go ahead — well in excess of projected LNG demand in 2025 (22–34 Tcf). Although not all proposed projects will proceed, capacity is still set to rise considerably and exceed demand. Does this leave any room for North American shale LNG? Yes, because of the cost advantage of North American gas.

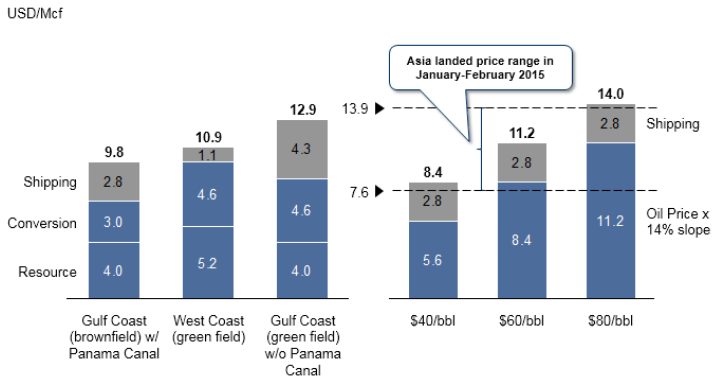
Figure 4: There is enough gas available at Henry Hub for export



North America natural gas resource potential after supplying local demand (which is expected to range from 30 to 35 Tcf/year from now to 2025)
Sources: EIA; SBC analysis

The landed cost in Asia of North American LNG will be the Henry Hub (spot) price plus liquefaction (including conversion margin) and shipping costs. This would amount to roughly $10-$13/Mcf and would make LNG production from most North American projects competitive with other suppliers. A prolonged oil-price slump could render North American LNG, especially from greenfield projects in the Gulf Coast, less price competitive with oil-linked gas contracts from Australia and the Middle East. However, with an oil price at $60/barrel (bbl), LNG exports from the North American West Coast and from Gulf Coast brownfields are still "in the money" and expected to grow rapidly. Furthermore, the true advantage of North American LNG may be greater, as many recent international LNG projects have incurred substantial capital overruns and delays (see figure 5, below). There are 36 proposed export terminals in North America; planned capacity amounts to 12 Tcf in the U.S. and 8 Tcf in Canada. Federal regulators have already approved 7.5 Tcf of this capacity, although only 1 Tcf has site approval. Nonetheless, the low cost of the majority of North American gas production supports a competitive product once chilled and shipped to international markets.

Figure 5: North American LNG landed cost to Japan (assuming 15% internal rate of return on liquefaction)



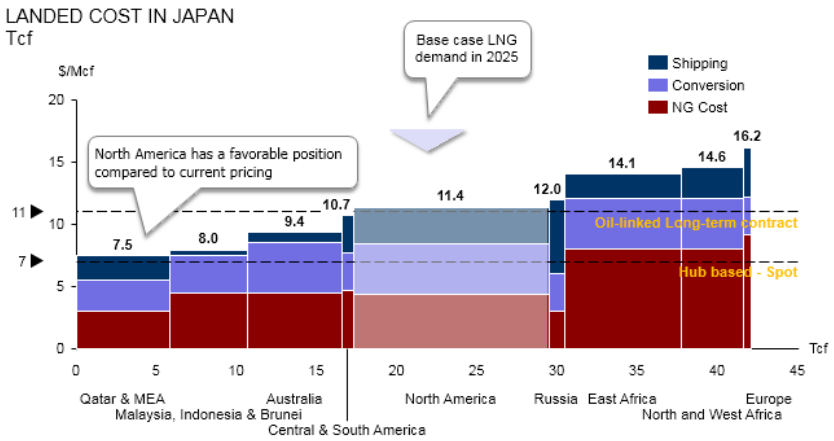
Sources: IHS CERA; CSFB; Citi; MS; SBC Analysis

As well as a structural cost advantage, there is an important risk advantage associated with North American gas production. Projects are mostly onshore, so are less susceptible to weather disruption and deposits can be brought on stream in smaller increments than generally is possible in greenfield projects in other regions. In addition, onshore wells in North America are better adapted to the rapid introduction of technological innovations than offshore wells elsewhere. North American gas production is also spread out over a wide geographical area, yet interconnected by a highly evolved pipeline network, further diminishing the risk of large supply shortages. Collectively, it is easy to see how North American LNG projects have risk and cost advantages over most projects in other countries. And Asian customers would welcome supply diversity from the U.S. and Canada.

Global Gas Market Convergence: Not "If" but "When"

Existing gas-pricing structures look precarious in the face of excess North American gas and planned production from other countries. There are three pricing regimes for major natural gas markets today — (1) hub-based spot pricing in North America, (2) oil-price-linked, long-term contracts in Asia, and (3) a hybrid of crude-linked long-term and hub-based spot pricing in Western Europe. Historically, the highest prices are in Asia, which has been perennially short of gas. Japan's nuclear-plant disaster in 2011 made the Asian supply situation worse, as a large portion of Japanese power-generation capacity switched from nuclear to gas. In addition, some formerly large LNG exporters, including Malaysia and Indonesia, are becoming net importers. Most of the natural gas supply to Asia is in the form of LNG, and global LNG production capacity has been limited to date. This has resulted in a high degree of uncertainty in relation to the continuity of supply, forcing consumers to enter into long-term contracts at oil-based prices.

Figure 6: North American LNG will enjoy a favourable position in the LNG supply curve

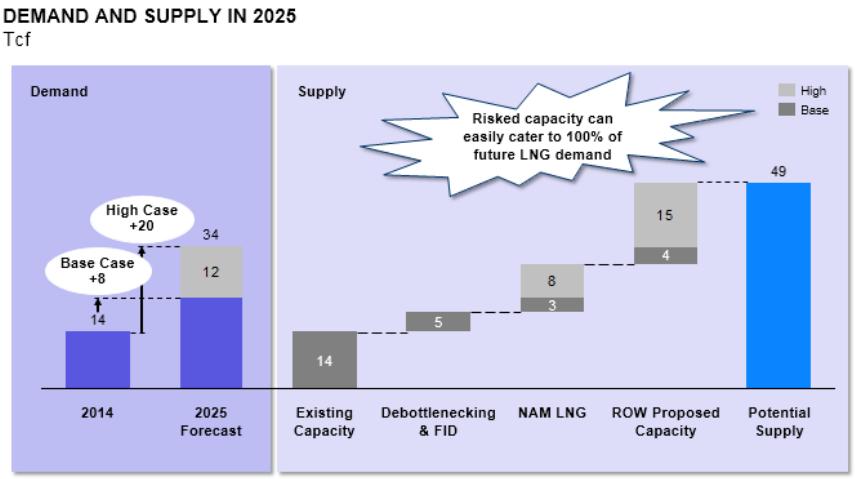


Sources: IHS CERA; UD; DOE EIA; IEA; SBC analysis

We expect global gas demand to rise to 145 Tcf (or 184 Tcf in the high case) by 2025, from 120 Tcf today. A large portion (around 85% in the base case and around 82% in the high case) of total demand will be met by indigenous production or piped gas. The remainder (22 Tcf in the base case and 34 Tcf in the high case) will have to be supplied in the form of LNG, which, as the marginal source of supply, will continue to determine gas market prices, as it has over the past decade. However, the uncertainty surrounding LNG supply is likely to diminish, in view of the large volumes planned in North America and elsewhere.

Current global LNG demand is 14 Tcf, but we expect an increase in demand of between 8 and 20 Tcf by 2025. Given the various advantages identified above, as well as its geographical position, North America should supply a large share of the world's incremental LNG requirements. In addition, as the marginal supplier in the LNG supply curve, North American LNG will determine the market price of LNG (see figure 6, above). Our expectation is that North American exports will start in the 2017-2018 timeframe, and have the potential to rise rapidly to between 3 and 11 Tcf a year by 2025. In other words, North America could contribute up to 100% of incremental (base-case) LNG demand (see figure 7, below). Even if North American exports are in the middle of the range (~6tcf), existing final investment decisions/debottlenecking supplies from the rest of the world (5 Tcf) come to the market, and only half of the proposed non–North American projects are eventually completed, we get more than two times coverage of the base-case incremental global LNG demand and greater than 100% coverage of high-case demand. At this point, supply uncertainty will have transformed into excess supply in search of demand. That is a situation under which markets tend to break.

Figure 7: North America well positioned to cover a large portion of incremental LNG demand



Sources: IHS; EIA; Wood Mackenzie; SBC analysis

Signs of stress can already be seen. Excess supply in Asia, due to a combination of lower-than-expected demand growth and rising supply from international projects, has helped halve the spot price of LNG in Asia (Asian spot gas prices are not oil-linked, but the volumes are much smaller than oil-price-linked long-term contracted gas) to around $7/MBtu (million British Thermal Units). Surplus LNG flowing to Europe from Asia, meanwhile, has made European hub prices converge with those in Asia. However, the full market impact of a permanent shift from supply uncertainty to excess supply is yet to be seen, given the large volumes of LNG from North America and other countries expected to reach the market by 2025. The resulting market pressure could usher in further convergence of Asian and European spot LNG prices with North American prices.

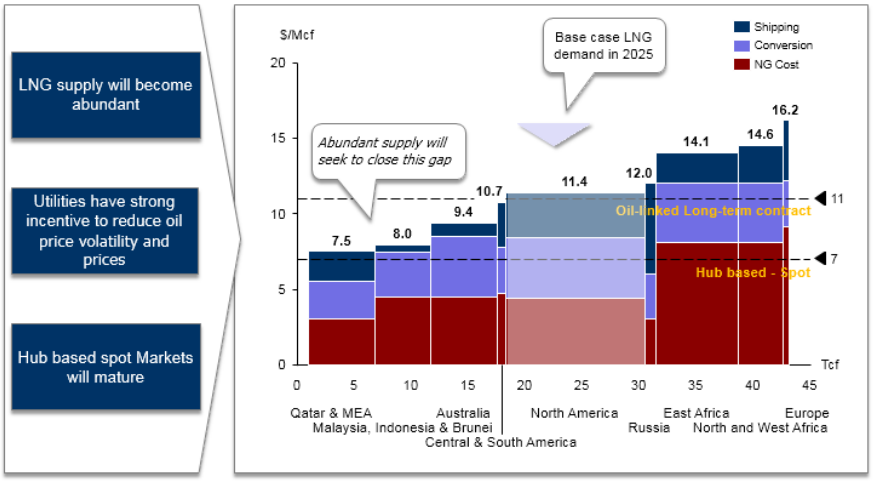
But the decrease in LNG prices is not limited to spot prices. The collapse in oil prices has resulted in a fall in long-term, oil-indexed prices in Asia to around $11/MBtu. As a result, North American LNG exports to Asia look less profitable than they did a year ago. In this context, a downturn in oil prices lasting several years would accelerate the decline in regional gas prices towards the level of North American LNG prices. Yet such a forecast may be premature; we believe that, when oil prices rebound, the price of Asian oil-linked LNG contracts will recover too. This will cause global gas prices to diverge again, until North American LNG exports become available, re-establishing convergence.

The gross imbalances described above will not be resolved neatly, and will require extensive negotiations between numerous companies and governments, as well as massive expenditure on gas production, liquefaction, and transportation infrastructure. Many investments will probably not proceed for financial or regulatory reasons, and of those that do progress, some will experience cost and timing overruns. The recent fall in oil prices has already put significant pressure on the economics of projects in East Africa and, in particular, Australia. Even North America will face difficulties when its exports exceed 20% (or >6 Tcf)

of local consumption: the temporary strain of balancing local consumption with a high level of exports may cause short-term price spikes, and regulators may respond by capping exports. Yet, despite all these uncertainties, there will be enough gas to instigate a new and lasting era of convergence.

The new order should evolve in phases. In the first, sufficient LNG volumes will be made available to the market to begin to break the link with crude oil prices in supply contracts. Sustained lower oil prices will reduce the incentive to move away from oil-price linkage, but utilities will continue to try to break the link in order to shield themselves from oil-price volatility. We are already seeing the initiation of this phase in cases where volumes are contracted from the U.S. As volumes increase, spot trade will become more liquid. This will trigger the second phase, in which price volatility will diminish, encouraging more spot buyers to participate in the market. As trade expands, conversion and transportation costs will benefit from economies of scale, and spreads will be narrowed. This will usher in the final phase: hub-based gas-on-gas pricing (see figure 8, below).

Figure 8: Current oil-linked long-term contracts will eventually break



Sources: IHS; EIA; Wood MacKenzie; SBC analysis

This shift will be driven by sizable financial incentives. In terms of absolute price differentials, we believe the incentive could eventually become significant again, though not as high as it was before oil prices collapsed. By the time the final phase is complete, which may be after 2025, gas-price ratios could be 1:1.75:2.5 (North America:Europe:Asia). Given our expectation for Henry Hub prices, this implies that the spread between Asian and North American prices could shrink by 50% (or more) from the early 2014 level. Utilities in Japan and South Korea will start experiencing this phenomenon in the coming decade and will be unable to resist buying in the spot market. They may even begin to revise existing contracts and encourage the development of trading hubs to replace long-term, take-or-pay contracts. This happened during the deregulation of U.S. gas markets: before the mid-1980s, the U.S. gas market was highly regulated – not unlike the global gas market today. Following the

Federal Energy Regulatory Commission's deregulation of the gas market, however, large amounts of gas became available, catalysing the development of a spot market in which prices were significantly below those in the long-term, take-or-pay contracts that utilities then had with gas suppliers. The utilities rejected their contracts *en masse*, claiming a form of *force majeure*. It was a multibillion-dollar debacle, resulting in the cancellation of take-or-pay contracts and a universal switch to the spot market. The same incentives will arise in Asia over the next decade, and some of the same players will face the same choices.

Conclusions

Persistently low oil prices have the potential to hasten the current convergence of regional gas prices. However, it remains uncertain whether or not such a situation will arise. Should oil prices return to the $80-$100/bbl range, global gas markets are likely to diverge again until significant amounts of LNG supply from the U.S. and Canada reach international markets. Eventually, North America, as a low-cost and abundant source of LNG production, remains in the best position to become the marginal supplier and to force the lasting convergence of gas prices.

Therefore, the imbalance that we see developing is still mostly to be expected. Natural gas is a necessity to modern economies. It is unlikely that we will find and develop the exact amount needed. The availability of unconventional gas in North America has tipped the balance domestically in favour of supply and may have a similar effect on global markets – to say nothing of the prospects for unconventional gas outside North America. Now that the innovation in gas recovery has become clear, the imbalance and resulting market stress become more a matter of timing. And timing is critically important in a capital-intensive industry like oil and gas.

Consequently, decision makers both in the public and private sectors will need to gauge the implications of a long-term market shift. For example, if large volumes of LNG from North America become available on the global market, should operators adjust their plans for the development of unconventional and frontier resources? And, if so, how? What about LNG development in regions where the cost of developing LNG projects is high, such as Australia and East Africa? Will chemical and energy-intensive manufacturing companies slow down their move into the U.S. even if it remains marginally cost-advantaged or maybe even cost-neutral, after the cost of transporting finished products to demand centres in Asia has been taken into account? What will countries with ambitious plans to develop renewable resources do? Will cheap gas deal clean technology another blow? Will the growth of coal-fired power in places like China stall? Questions such as these form a complex strategic picture for players across the energy value chain.

Ultimately, if the resource exists – and we know it does, in abundance – the industry will find a way to get it to the desired consumption points. Consequently, convergence of gas markets, excluding transportation costs and other structural factors, is not a question of "if" but of "when" – and, based on the evidence, it may very well begin to happen in the next decade.

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