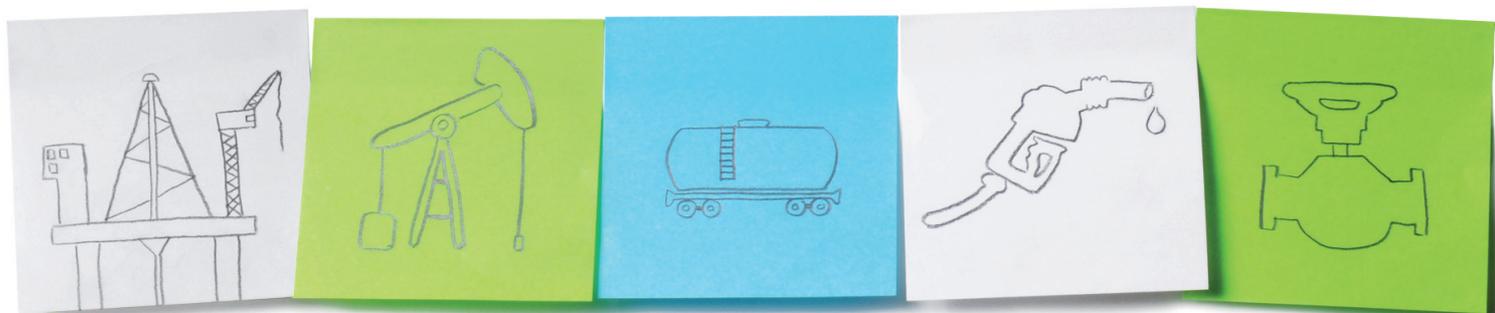


## Oil and Gas Reality Check 2013

A look at the top issues facing  
the oil and gas sector





# Foreword

## A return to industry fundamentals

The 2010 edition of Reality Check was heavily influenced by the gyrating price of crude oil in the preceding 12-18 months. As the price went from a high of nearly \$150/barrel in mid-2008 to below \$40/barrel at the beginning of 2009, the sector was trying to make sense of investment decisions and production costs that seemed to be in diametric opposition to the direction of the price. Naturally, the Deloitte Touche Tohmatsu Limited Global Energy & Resources group focused its list of top trends on the economic uncertainty and its impact on capital availability. We discussed the slow approval of new capital projects, margin squeeze due to escalating costs, the resulting talent squeeze due to early retirements, and increased merger and acquisition (M&A) activity where acquisition of barrels seemed cheaper than exploring for them. This gave rise to the increased sentiment of resource nationalism and we proclaimed the end of "easy oil".

Four years later, few of us are surprised to find that the same issues persist. After all, in a sector that is based on risky activities – making 30 year capital investment decisions with commodity prices that rise and fall daily, talent that takes years to develop, and an exploration environment that has been described as deeper, darker and wetter – why would we assume that things will change? Indeed, to use a cliché, the more things change the more they stay the same.

In 2011, our Oil and Gas Reality Check predicted that hydrocarbons would continue to constitute the world's primary energy supply, despite significant progress in alternative energy sources. We followed that by focusing on the rise of unconventional oil and gas resources, predicting that recent discoveries of shale gas in the US will change the landscape in ways previously unknown. We crossed the Atlantic and discussed the re-emergence of the North Sea oilfields, and predicted that Asia will become the "hot bed" of M&A activity following the accumulation of global energy assets by various Northeast Asian National Oil Companies (NOCs).

Last year, we proclaimed Iraq and Libya open for business, re-emphasized the impact of shale gas and expanded the focus globally, discussed Chinese NOCs' exploration activities, and highlighted the rise of a new breed of NOCs – the energy-consuming NOCs emerging from Asia. Against the backdrop of the US emerging as an energy producing powerhouse, we discussed the diverging WTI and Brent benchmarks and the possible decoupling of oil and gas prices; noting the 11% increase in the price of oil (WTI) from November 2010 to 2011 versus the 1.3% decrease in the price of natural gas (Henry Hub). In our last report, we also returned to the talent issues, focusing on the possible shortage in Canada's oil sands sector.

This year's Oil and Gas Reality Check marks a different approach. Rather than simply identifying the issues that are of interest to the sector, we have focused on the five primary challenges and attempted to predict a direction which these trends will follow. Looking back at our previous Reality Check publications, I found the types of challenges to be similar. Over the years, some occupied a higher position on the "concern scale" than others, but very few proved to be non-issues that have disappeared.

The 2013 Oil and Gas Reality Check focuses on assessing the industry fundamentals of each trend – the supply, demand, macroeconomic, regulatory, cost, price, and competitive behavior factors – allowing us to draw insights and describe what may unfold over the short and the long-term.

We begin with the discoveries of unconventional oil and gas, and shale gas in particular. With new countries entering the ranks of net energy exporters, one may proclaim a global revolution is at hand with fundamental shifts in energy geopolitics due to newly found energy independence. A closer examination of the development progress of countries with major shale gas resources reveals a vastly different picture. Countries that can commercially produce unconventional and conventional gas seek higher returns by exporting or planning to export liquefied natural gas (LNG) to Asia Pacific countries which have historically agreed to long-term purchase contracts at oil-indexed prices. The expected increase and diversity of LNG supply is spurring transition away from oil price indexation, and the rise of gas hub and hybrid price indexation.

The discoveries of new resources across various geographies coupled with the technical challenges of developing those resources are softening governments' contract terms, fiscal takes, and other policies; all indicators of the degree of resource nationalism. As production efficiency rates and capabilities improve, will resource nationalism surge? Or, will resource nationalism in terms of government policy pale in comparison to the competitive rise of NOCs? We assess what these impacts will be to International Oil Companies (IOCs) and other sector players, such as Oilfield Services (OFS) companies.

Just as our 2010 Oil and Gas Reality Check was marked by economic uncertainty, this year's report also indicates that certainty is far from the rule and uncertainty has returned. Therefore, how companies react to and deal with this uncertainty is changing the notion of a singular business model and giving rise to different business models.

The 2013 Oil and Gas Reality Check represents our team's findings supplemented by expert perspectives from our partners, clients, and industry executives. Given the report's theme of reviewing the industry fundamentals, our research and analysis encompass views from policy makers, energy market traders and analysts, energy producers and consumers across the spectrum of size and sub-sector, both privately- and government-owned.

As we conclude this year's report, we must start assembling our views for the next one. For that purpose, I would welcome any input and advice as to anything we might have missed, new items that could be included in the next report, and overall comments on the industry. Please do not hesitate to reach out to any of our sector leaders named in the Contacts page of this report, or please feel free to send me an email directly.

I would like to thank our contributors for providing their insight and expertise, and I hope that you will find this report informative, credible, and insightful.



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# 1. Shale gas – a global or regional resource?

The success of North American shale gas has created interest in duplicating the results in other countries; increasing the potential for shale gas to transform natural gas markets globally. An April 2011 study by the Energy Information Administration (EIA) estimated that world shale technically recoverable resources outside the US were 5,760 trillion cubic feet (Tcf), an increase of more than 40% in world gas resources.<sup>1</sup> The study sparked widespread interest in international shale as countries hoped to increase energy supply security and boost economic growth. However, the presence of shale gas in the ground does not guarantee the unearthing of a fortune.

Given the greater technical challenge of shale gas and higher development costs, exploitation of shale resources is not easily replicable in other markets. While some countries are making progress, over the next one to three years it will remain a largely regional resource with an uncertain impact on the global market beyond this timeframe.

We examined countries with major shale gas reserves and found four that are representative of the distinct phases of resource development:

**Poland** – struggling to maintain its nascent shale industry, due to a recent reduction in the estimated size of its shale resources, as well as declining company interest from poor initial results.

**China** – working diligently to provide an investment environment conducive to shale development, but given rising domestic demand and a challenging exploration environment, it is unlikely to become a shale exporter.

**Argentina** – experienced positive production results and is aiming to scale-up production, bringing new shale basins online.

**United States** – home of the shale gas revolution and poised to globalize its shale resources through exports of LNG, assuming favorable exporting regulation and permitting.

Each country is positioned differently on the spectrum of shale gas development. The mere existence of shale gas does not immediately lead to energy independence or make a major impact on the global energy market. The shale gas development spectrum serves well to summarize each country's potential for reaching global gas development. The framework below describes the broad spectrum of development phases, and allows us to assess the main stages of development that define a country's path from testing initial gas flows to making multi-billion dollar investments in export infrastructure.

## The quick read

- Over the next one to three years, shale gas will continue to be a largely regional resource with only a limited impact on global markets.
- Although other countries want to replicate the North American shale gas revolution, they must overcome more challenging geology, and gaps in technology, infrastructure and domestic service capability before commercial production can begin – as well as political and environmental obstacles in some jurisdictions.
- Low per capita gas reserves and rising domestic demand are long-term limitations for the export potential of some countries.

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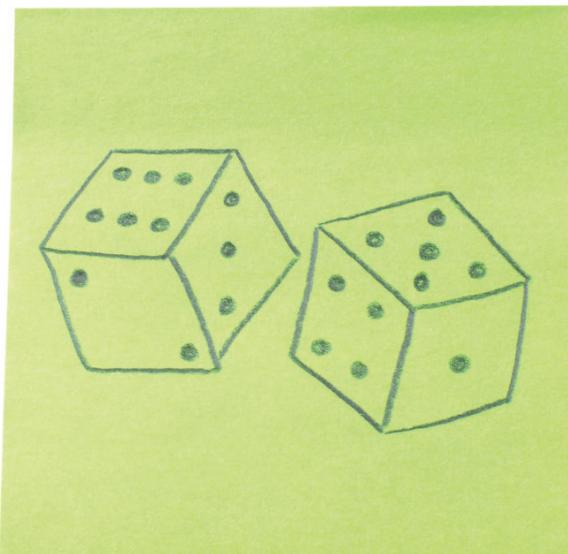


Figure 1.1 Stages of Development for Shale Gas

Stage	Subsector focus	Shale % of natural gas production	Development objective	Industry competition	Representative country	Brief description
<b>Dormant</b>	E&P	0 – 1%	Feasibility	Non-competitive government R&D, entrepreneurial independent(s)	Poland (current)	<ul style="list-style-type: none"> <li>• Little-to-no activity</li> <li>• Shale exploration and production (E&amp;P) driven by entrepreneurial independent company or government research and development (R&amp;D) program</li> </ul>
<b>Nascent</b>	E&P	1 – 5%	One best way (target single shale basin)	Cooperative joint ventures; government R&D	China (current)	<ul style="list-style-type: none"> <li>• Drivers for shale are growing natural gas imports and large shale resources</li> <li>• Target the single best basin for testing</li> <li>• Governments offer subsidies to encourage development</li> </ul>
<b>Incubator</b>	E&P	5 – 15%	Multiple best ways (target multiple basins)	Growing competitive industry	Argentina (current)	<ul style="list-style-type: none"> <li>• Commercial volumes of shale produced</li> <li>• New basins are tested for development</li> <li>• Small companies with niche expertise compete with large companies seeking advantage through economies of scale</li> <li>• New entrants and increased M&amp;A</li> </ul>
<b>Decoupler</b>	Midstream/ Downstream (domestic)	>15%	Link new supplies to demand centers	Fierce competition as shale profit margins compress due to lower prices	Argentina (outlook)	<ul style="list-style-type: none"> <li>• “Supply shock”; domestic gas price moves down versus global pricing points</li> <li>• Large capital investments needed for processing facilities and to move rising volumes to demand centers</li> </ul>
<b>Globalizer</b>	Midstream (global)	N/A*	Access new sources of demand	Global competitors; exports as a breakout strategy	US (current/outlook)	<ul style="list-style-type: none"> <li>• Companies seek higher price realizations in global markets</li> <li>• Ability to globalize shale production due to high gas reserves per capita and low domestic gas demand curve</li> </ul>

\* Globalizer role is more a function of reserves per capita than shale as a percentage of gas production.

## Regionalized development of shale gas – country case analysis

Let us explore the five stages of developing shale gas by analyzing each country's position and potential for exploiting this seemingly abundant resource.

### Poland – Nascent to Dormant

Currently, Poland's shale industry is struggling to maintain international interest following a series of setbacks over the past year that threaten to push it from a Nascent stage back to Dormancy.

Poland consumes 1.66 billion cubic feet per day (Bcf/d) of natural gas and imports nearly 70% from Russia, so there was considerable enthusiasm when the EIA estimated the size of its shale gas resources at 187 Tcf.<sup>2</sup> Poland's shale is at depths between one to two miles, deeper than similar US shale plays, which negatively impacts cost.<sup>3</sup> Although the country has slightly lower drilling times than US shale wells, a hydraulically fractured horizontal well in Poland costs nearly \$15-\$20 million.<sup>4</sup>

The country's current gas pipeline infrastructure is limited and a small services industry with only 15 drilling rigs – only five capable of drilling deep shale wells – inhibits development.<sup>5</sup>

**Outlook:** Over the short-term, Poland will struggle to develop its Nascent industry. While 111 exploration concessions were granted to nearly 30 companies, only some 33 test wells were completed with 10 hydraulically fractured, and the wells failed to yield commercial volumes of gas.<sup>6</sup> ExxonMobil announced it would exit the country after the flow rates from two wells proved disappointing and other companies are following suit.<sup>7</sup>

Despite the setback, the Polish government seeks commercial production by 2015 and plans 270 new shale wells through 2020.<sup>8</sup> To reinvigorate interest, the government aims to create a stable investment environment by establishing a maximum government take of 40% in its new hydrocarbon legislation.<sup>9</sup> The Polish Geological Institute is also set to release a new resource assessment in 2014 that could increase its shale estimate by seven times (following a 2012 assessment that reduced the estimate by over 90%) driven by an estimated 25-30% resource recovery based on new data.<sup>10</sup>

It will be challenging for Poland to reach the Incubator phase if new investments do not materialize or if drilling results do not improve. Despite a forgiving gas demand curve with a 1% Compound Annual Growth Rate (CAGR) over the past five years, the country still has relatively low proven reserves of 88 thousand cubic feet (Mcf) per capita. Even if the country were to begin commercial production of shale gas, the impact of its production on regional markets will be limited since it will likely use domestically produced gas to offset its high dependence on imported gas.

### China – Dormant to Nascent

China is moving from a Dormant to a Nascent stage of shale development, but is unlikely to be a Globalizer. The US Energy Information Administration (EIA) estimates that China has 1,275 Tcf of technically recoverable shale gas resources, while China's Ministry of Land and Resources has a more conservative 886 Tcf estimate.<sup>11</sup>

The most active shale basin is the Sichuan Basin with nearby access to water resources that makes it suitable for hydraulic fracturing despite the country's low per capita water supply.<sup>12</sup> The basin is a mature region of conventional natural gas production with over 11,000 miles of gas pipelines.<sup>13</sup> However, the eastern part of the Sichuan basin contains extensive steep folding and faulting, which complicates horizontal drilling techniques, and the western part is deeper, which increases drilling costs. As a result of this geological complexity, drilling costs for shale gas can run as high as \$16 million per well.<sup>14</sup> The region also has high population density, which can make land more difficult to access.

**Outlook:** Over the short-term, China will continue in a Nascent stage with success in the Sichuan basin a critical indicator of its transition to an Incubator. China's 12th Five Year Plan sets aggressive targets for shale gas production of 0.6 Bcf/d by 2015, with plans to scale-up production to 5.8-9.6 Bcf/d by 2020.<sup>15</sup>

In order to meet these targets, between 1,200-1,500 wells need to be drilled in the country,<sup>16</sup> but only 60 exploration wells have been drilled to date.<sup>17</sup> To improve project economics, in 2012 the Chinese government initiated subsidies for shale gas production through 2015 that will reduce costs by 20-30% and has been experimenting with liberalized gas prices in the Guangdong and Guangxi regions since 2011.<sup>18</sup>





China also will be challenged by a service industry that is inexperienced with shale and with limited domestic drilling technology for multi-stage hydraulic fracturing. Although China is making investments in North American shales to acquire the necessary technology and expertise, it will take time to apply this knowledge to the home market.

Despite its prospects, China is unlikely to become a shale Globalizer because of low reserves of 80 Mcf per capita and a steep gas demand curve, with a 13% CAGR over the past five years, driven by an energy policy prioritizing gas over coal to meet future energy demand. Confronted with these constraints, China will be compelled to satisfy domestic gas demand rather than seek new demand in external markets.

#### **Argentina – Nascent to Incubator**

Argentina is moving from a Nascent stage to an Incubator. Argentina has an estimated 774 Tcf of technically recoverable shale gas resources. The largest and most active shale basin is the Neuquen Basin where the Vaca Muerte shale holds an estimated 240 Tcf.<sup>19</sup> Neuquen currently accounts for nearly half of the country's natural gas production and has an established pipeline infrastructure to process and transport gas to market. The region also has good access to water needed for hydraulic fracturing and an established domestic service industry.

**Outlook:** In 2012, Argentina took two steps that could push the country from Nascent to Incubator – the nationalization of YPF and an increase in Gas Plus pricing. In April 2012, the government nationalized YPF accusing Repsol of prioritizing an overly-aggressive dividend policy over investments to increase production.<sup>20</sup> A newly nationalized YPF pledged to spend \$1.5 billion to test unconventional drilling techniques and plans to spend \$12 billion on shale from 2013-2017.<sup>21</sup> YPF is also working to make beneficial global partnerships to attract capital and expertise to increase shale production by entering into joint ventures (JVs) with Chevron, ExxonMobil, and Gazprom, with talks to form several others.<sup>22</sup>

One of the major impediments to investments in the country's gas resources has been a low government-established reference price of \$2.50/MMBtu – far below the price level needed to encourage domestic production. To incentivize shale production, the government created the Gas Plus program that allows producers of unconventional gas assets to offer “new gas” at a higher price, which was increased in 2012 to \$7.50/MMBtu.<sup>23</sup>

Over the short-term, Argentina will continue as an Incubator assisted by recent successes in the Vaca Muerte. As predicted for an Incubator, success in one basin has opened up opportunities to move to other shale plays. Argentina is assisted by the stacked pay of the Neuquen basin shale with the Agrio above the Vaca Muerte and the Los Molles formation below it. Drilling has also begun in the pre-Cuyo basin north of Neuquen.<sup>24</sup>

Long-term, Argentina has the potential to become a Decoupler as other shale basins in the country are brought online. The extensive midstream infrastructure in the Neuquen basin will assist the transition from an Incubator to a Decoupler. However, the other shale basins in the country do not have as highly developed a midstream infrastructure as the Neuquen basin and will require additional capital, likely from foreign sources, for development. These capital requirements could be prohibitive in a low price environment and limit movement toward becoming a Globalizer of shale resources. However, with gas reserves of 318 Mcf per capita and a modest gas demand curve with an average 1% 5-year CAGR, Argentina is not constrained from becoming a Globalizer if it continues to attract investment.

#### **United States – Poised as a Globalizer**

EIA's initial 2011 shale resource estimate for the US of 862 Tcf was later revised to 482 Tcf based on new drilling and production data from the Marcellus shale basin.<sup>25</sup> US shale emerged from Dormancy in the late 1970s when the Department of Energy (DOE) initiated a shale R&D program that helped to fund Mitchell Energy's first horizontal well.<sup>26</sup> By 1997, the US entered the Incubator stage as shale gas production reached commercial viability with the introduction of slickwater fracking.<sup>27</sup> Success in the Barnett shale play led to the application of shale extraction technologies to other sites across the country such as Fayetteville, Haynesville, Marcellus, Eagle Ford and Bakken.

The US entered the Decoupler phase in 2008 when the shale supply shock, combined with a bursting of the commodities bubble that same year, led gas prices to fall 55% from nearly \$11/Mcf to just over \$5/Mcf.<sup>28</sup> The decline in the wellhead price for gas marked a significant shift in domestic prices versus world price points. The US wellhead price for gas fell from a \$0.94 (16%) premium over the UK National Balance Point price in 2007, to a \$5.02 (56%) discount in 2011, with a \$0.78 (10%) discount to the Japanese LNG import price moving to a \$10.72 (73%) discount over the same period.<sup>29</sup> By mid-2012, companies began to report billion dollar impairments on shale assets in North America due to prevailing low prices, while midstream companies struggled to keep up with changing gas flows and demand for new infrastructure.

**Outlook:** The US is now on the cusp of becoming a shale Globalizer. Natural gas in storage reached a new historic high of 3,929 Bcf in November 2012 as marketed gas production reached a new high of 70 Bcf/d.<sup>30</sup> With low prices and surging production, US gas producers want to tap global markets to increase their price realizations for natural gas. Currently, DOE is considering over 20 LNG export permits totaling 27 Bcf/d, which would make the US the largest exporter of LNG in the world if all were approved. The US is not constrained from an export decision by its reserves per capita or domestic demand as it moves towards globalization of its shale gas. The country has high gas reserves of 966 Mcf per capita and a moderate gas demand curve with a 1% CAGR. In the next chapter, we discuss the impact of LNG exports on US and global gas prices.

**Our view**

The US shale gas revolution was three decades in the making with incremental progress through the five stages of development. Although other countries, particularly Poland, China, and Argentina, want to replicate this success, these countries still have a long road ahead before they can begin to see the gas volumes and supporting infrastructure needed dramatically to lower domestic natural gas prices and create export opportunities (see Figure 1.2). While countries may enter into partnerships with shale-experienced oil and gas companies and oilfield services companies to unlock shale resources, nonetheless limitations such as low reserves per capita and steep demand curves can constrain countries from becoming shale exporters.

**Figure 1.2 Summary of Development Outlook for Major Shale Resource Countries**

Country	EIA Resource Estimate (Tcf)	Services Industry	Pipeline Network	Water Access	Geological Complexity	Gas Reserves/ Capita (Mcf)	Shale % of natural gas production	Outlook
Argentina	774	●	●	●	●	318	<5%	<ul style="list-style-type: none"> <li>• Success during the Nascent stage is driving investments needed as an Incubator</li> <li>• Maintaining a favorable investment climate is needed to become a Decoupler</li> </ul>
China	1,275 (886)*	●	●	●	●	80	<3%	<ul style="list-style-type: none"> <li>• International partnerships needed to overcome geological complexity</li> <li>• Services sector needs shale experience and water is a concern</li> <li>• Unlikely to be a Globalizer</li> </ul>
Poland	187 (12 – 27)†	●	●	●	●	88	N/A	<ul style="list-style-type: none"> <li>• Stable investment climate needed to reinvigorate investments</li> <li>• Must demonstrate commercial viability of its shale</li> <li>• Unlikely to be a Globalizer</li> </ul>
United States	482	●	●	●	●	966	23%	<ul style="list-style-type: none"> <li>• Poised to be a Globalizer with LNG exports</li> <li>• Government export approvals are determining factor</li> </ul>

\* Ministry of Land and Resources (China) estimate.

† Polish Geological Institute (Poland) estimate.

Tcf = Trillion cubic feet

Mcf = Thousand cubic feet

● = low barrier    ● = moderate barrier    ● = high barrier

Apart from the United States' pending exports of LNG, the reality is that shale will continue to be a regional resource with limited impact on the global market over the short-term.

## 2. LNG pricing – the end of oil indexation?

### The quick read

- Oil indexation will be one of several pricing approaches for long-term LNG contracts in Asia Pacific.
- Additional, diverse supply coming online from 2017 will create competition on price and non-price terms, including use of gas hub and hybrid indexation.
- Prospects for an Asian regional gas price benchmark are dim, due to challenging regulatory and infrastructure barriers.

The prospect of the US globalizing its shale gas resources via LNG exports has many observers (especially in Asia), hopeful that US LNG indexed to Henry Hub prices will also be exported, eroding the hold of long-term LNG contract price formulae indexed to crude oil. At a conference in September 2012, Japan's trade minister described global shale gas production as causing a "paradigm shift" in LNG pricing and called on producers and consumers to "come up with a new method to replace oil-linked indexing" as little rationale exists to support the current pricing system.<sup>31</sup>

The minister's remarks are understandable in a year when Japanese LNG spot prices rose to a high of \$18/MMBtu while US Henry Hub gas prices dipped to a 10-year low of \$1.95/MMBtu. Moreover, Japan's trade deficit reached \$76 billion primarily due to LNG imports, which surged after the Fukushima nuclear disaster shut down the country's nuclear generation capacity. In 2012, Japan spent nearly \$65 billion on LNG imports, a 25% increase from 2011, whereas volume imported increased by only 11%.<sup>32</sup> These figures illustrate Japan's need for energy supply security amidst price escalation.

From the perspective of long-time LNG producers (such as Qatar, currently the world's largest LNG exporter), any agreement to supply contracts de-linked from oil prices would undermine the premium pricing they have enjoyed with the rise in global oil prices.

Up and coming LNG producers with greenfield liquefaction projects rely on oil-linked pricing to achieve internal rates of return and investor confidence to commit long-term financing. This is particularly the case for high cost Australian LNG projects, which have increased to as much as \$4,000/tonne (of LNG), compared to \$1,500-\$2,500/tonne in other regions.

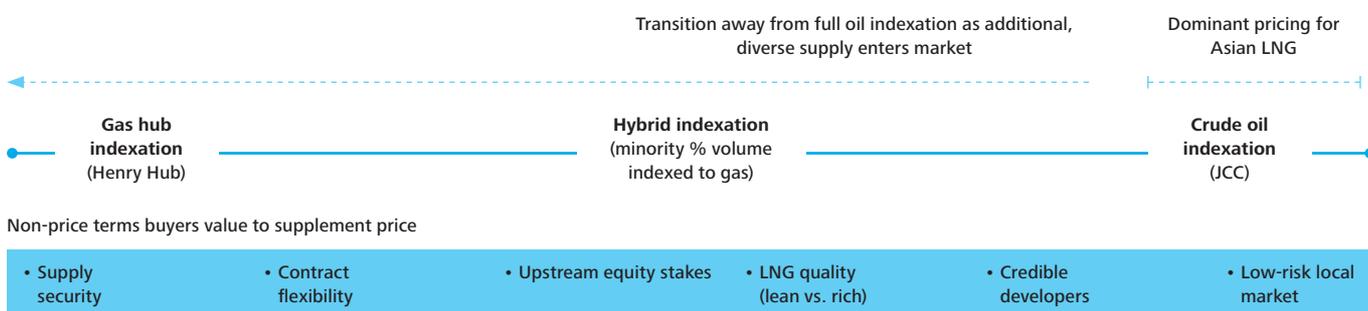
The anticipation of US LNG exports potentially undermining oil-price indexation has heightened in light of recently announced Henry Hub-linked contracts. BP, Cameron LNG partners, and Cheniere have agreed to supply Asia Pacific buyers with US LNG linked to Henry Hub gas prices, which could see Japan's import prices in the range of \$10-12/MMBtu compared to \$14-16/MMBtu for oil-linked contracts.<sup>33</sup> Most striking is that BP, through its subsidiary BP Singapore, signed the Henry Hub-linked sales and purchase agreement (SPA) with Kansai Electric for LNG not exclusively produced from US gas, but gas from BP's global portfolio.<sup>34</sup>

Rather than signaling a complete switch from oil to gas hub indexation for long-term LNG contracts in Asia Pacific, these recent developments reflect a transition towards a pricing spectrum where oil indexation is one of several pricing mechanisms used (see Figure 2.1).

The increased supply from diverse basins and producers will be complemented by growing demand with buyers of different needs, as well as un-contracted, surplus capacity across the LNG value chain.

The diversity across producers and buyers creates a competitive marketplace whereby producers can compete not only on price, but also non-price terms, making crude oil indexation more palatable or perceived volatility risk in gas hub indexation acceptable. Another way to mitigate commodity price volatility risk is hybrid indexation, where a percentage of volume is indexed to a gas hub, and the remainder indexed to oil. For LNG sourced from US gas and produced by companies without market share to protect, indexation to Henry Hub plus a price escalator is the likely formula.

Figure 2.1 Spectrum of LNG Price Indexation



### Next evolution of LNG pricing in Asia

LNG has grown from less than 5% of world gas consumption in 2000 to over 10%, enabling gas to be more of a global commodity. Despite this growth, the global gas market remains regionally fractured due to high cost transportation and regulatory barriers. Thus, gas prices remain localized. LNG pricing is therefore regionally fractured with North America referencing Henry Hub, UK and potentially parts of Continental Europe referencing the UK's National Balancing Point (NBP) gas hub, Continental Europe referencing fuel oil or Brent prices, and Asia Pacific referencing the Japanese Crude Cocktail (JCC) benchmark, the basket of crude oil imported by Japan.

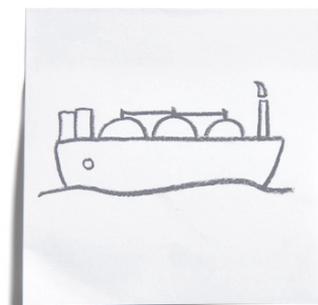
Crude oil, one of the most globally transparent and fungible commodities, emerged as the price reference for Asian LNG in the 1970s as a market-based factor to supplement pricing based upon project costs. Since then, LNG prices were assessed based on its percentage parity to oil on an equivalent MMBtu basis (e.g. 80% of oil prices when oil prices are converted from \$ per barrel to \$ per MMBtu). To manage oil price volatility, the S-curve price formula was introduced whereby a price ceiling and floor were set to protect producers in a low oil price scenario, and protect buyers in a high oil price scenario. In the 1990s, surplus LNG supply led to contracts with both S-curve formulae and lower percentage parity to oil. This held until the early part of 2000, when supply tightened swinging LNG prices closer to oil price parity. This history of LNG pricing approaches in Asia shows that if prices are correlated to anything, they are linked to supply and demand conditions and the reactions of producers and buyers.

Market conditions are now ripe for the next evolution in LNG pricing – indexing to gas hubs (i.e. Henry Hub) and supplementing non-price terms. This is not to say that oil indexation will be abandoned, but that pricing will be established along a spectrum of options as illustrated in Figure 2.1. Non-price terms that “sweeten” contract negotiations have been common practice, most notably the removal of cargo destination clauses in contracts, but the difference now lies in the range and types of non-price options that are increasingly possible, due to surplus capacity and diversity across producers and buyers.

### Loose, diverse supply market – driving price competition

There are 12 liquefaction plants under construction with an estimated 84 million tonnes per year (mt/y) due to come online by 2017, at which point there will be a surplus of LNG in the market. An additional 23 plants are planned or proposed, potentially adding nearly 170 mt/y in capacity by 2020. However, it is unlikely that all proposed capacity will come online as planned. From 2014-2020, global demand for LNG will likely double, with Asia accounting for over 60% of demand, including significant growth from China and India, and new regional importers such as Vietnam and the Philippines. Globally, 56 regasification terminals are under construction, planned or proposed across 20 countries, adding a potential of 166 mt/y in capacity. LNG tanker capacity will likely grow by 25% in the next 12 months as 83 tankers come online with some tankers not contracted in order to take advantage of arbitrage opportunities and spot trading.

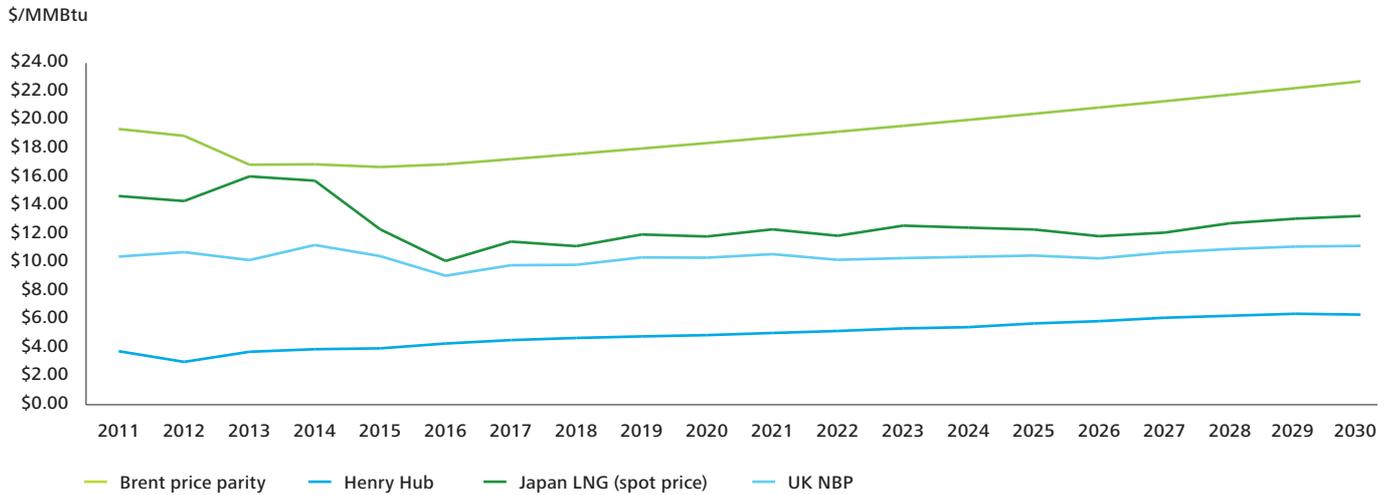
More diverse and competitively-priced supplies create conditions in the global LNG market that may lead to a transition away from oil-price indexation. In a recent report projecting the price impact of US LNG exports on global gas prices, Deloitte MarketPoint found that gas prices are sensitive to additional supply volumes, especially volumes priced competitively<sup>25</sup> (i.e. gas-to-gas pricing). Applying a core assumption that certain producers would price LNG competitive to oil-indexed prices in a scenario of additional supply, Deloitte MarketPoint's economic model projected Japan delivered prices dropping below \$14/MMBtu and tracking closely to UK NBP by 2015. Figure 2.2 shows Deloitte MarketPoint projected prices in major LNG markets compared to projected Brent prices on an MMBtu equivalent basis. The projected prices are based on a scenario of limited competitive pricing and no US exports, but even in this scenario, the gap between the Japan price and Brent is significant at about \$7/MMBtu by 2020. If the US exports 6 Bcf/d to Asia, the report found that Japan delivered prices decreased by an additional \$0.40 to \$0.60/MMBtu, depending on the market scenario. The study found that the structure of long-term LNG contracts would work to increase the price sensitivity to competitively priced supplies.



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**Market conditions are now ripe for the next evolution in LNG pricing – indexing to gas hubs (i.e. Henry Hub) and supplementing non-price terms.**

Figure 2.2. Projected Prices vs. Oil Price Parity (real 2012 \$/MMBtu)



Source: Deloitte MarketPoint analysis, April 2013 reference case

As noted earlier, we are already seeing competitive pricing dynamics in play as several LNG contracts linked to Henry Hub prices have been signed. A key aspect of additional supply is the volume available on a spot or short-term basis versus a long-term contracted, “take-or-pay” basis that can further drive transition from oil indexation. Spot and short-term contracts are priced based on competitive market conditions (e.g. seasonal demand, available spot supply) between buyers and sellers. If spot prices are lower than long-term contract prices, buyers will shift to purchasing more on the spot market, applying pressure to producers to lower long-term contract prices. In the recent years of tight supply, spot prices were close to or exceeded oil price parity. However, in a surplus supply market, spot prices can be set competitively.

In 2011, the volume of spot and short-term trades increased to 61.2 million tonnes, accounting for 25% of total LNG traded,<sup>36</sup> and is expected to grow further. This spot and short-term trading volume growth is impressive, considering it was about eight million tonnes ten years ago (8% of total LNG traded).<sup>37</sup> With upcoming un-contracted supply and tanker capacity, it will be important to see how spot and short-term trades grow and we can expect these competitive prices to impact pricing formulae for long-term contracts.

Supply volume is not the only factor driving competitive pricing behavior amongst producers.

Capital investment (driven by multiple factors such as gas source/geological formation, local market conditions, technology used, labor productivity), defines the margins within which producers can price LNG. The Australian LNG projects are on the higher end from \$3,000-4,000/tonne per annum (tpa) while Mozambique and US projects, represented by Sabine Pass (export only), are lower cost below \$2,000/tpa.

Aside from the widely reported factors causing budget overruns and schedule delays for Australian LNG projects, the projects are also among the most innovative with testing of new technology, such as Floating Liquefied Natural Gas (FLNG) plants, and production of coal seam gas. The projects also offered upstream equity stakes to Asia Pacific buyers, and consortia of experienced producers for upstream and downstream operations. These non-price factors offer value to buyers and help justify payment of oil-indexed prices.

#### Competing on non-price terms

LNG projects have significant diversity offering various non-price factors that meet buyers' needs. Gas source is a non-price factor to consider due to differences in energy content, or heating value. Unconventional gas, such as shale and coal seam, are less energy dense, or "lean", compared to conventional, or "rich" gas. Consumer countries have varying degrees of flexibility for LNG quality. Japan and Korea traditionally consume rich gas and have gas-burning appliances designed for high heating values, while China and India have more flexibility with LNG quality. Lean gas can be blended with LPG to produce the required heating values, which is why LNG quality differences have not stopped Japan from buying US and Australian LNG. Although blending to meet LNG quality specifications, especially for a high volume of LNG, is still a cost consideration on behalf of the buyer.

Supply security, or low risk of supply interruption, is another key non-price factor for Asia Pacific buyers. For Japan, Korea and Taiwan, lack of indigenous gas resources and gas pipeline infrastructure leaves LNG as the primary way to secure gas. The need for supply security translates into low price sensitivity for these Asian importers, and helps explain high spot prices. On the other hand, at lower gas hub indexed prices, buyers may be willing to accept lack of supply security, as is the case of the Cheniere Sabine Pass agreement with KOGAS, which is on an interruptible supply basis.

Buyers' and suppliers' tolerance for commodity price volatility risk is another key factor driving pricing approaches, giving rise to the use of hybrid indexation. Hybrid indexation indexes a percentage of contracted volume, usually a minority percentage, to gas hub prices with the remainder of the volume indexed to oil prices.

Recent studies, including the previously mentioned Deloitte MarketPoint report, modeling the movement of US domestic gas prices due to US LNG exports, concluded that there will be a marginal increase in Henry Hub prices.<sup>38</sup> Memories of \$10-12/MMBtu Henry Hub prices (2008) and uncertainty of US government approvals on export volumes have some market participants taking a cautious, wait-and-see approach.

Large-scale producers with gas plays and LNG plants across various basins are in a strong position to offer hybrid indexation pricing, which helps smooth variances for producers which engage in portfolio selling, or selling contracted volumes pooled from a global supply portfolio. One major LNG producer which markets from its global supply portfolio has an LNG price exposure of about 25% to gas hub pricing, and about 75% exposure to oil basket pricing – a ratio that reflects the capital intensity and supply diversity of their LNG projects.

#### Our view

As diverse supplies enter the LNG market over the next 12 months through to 2017, the dynamics of supply competition will drive transition away from contracts purely indexed to oil prices and at high oil price parity in the Asia Pacific region. Rather, we will likely begin to see a mixture of contract pricing approaches; prices set lower from oil price parity, hybrid indexation, and full gas hub indexation. Oil indexation will likely remain the predominant pricing approach due to concerns over gas and oil price volatility risk, and also because suppliers are able to offer value through non-price terms, such as quality flexibility, supply security, and equity stakes in upstream projects.

US LNG exports will be a major catalyst for the transition away from oil price indexation. However, it is important to stress that not all US-sourced LNG will be indexed to Henry Hub prices, and pricing will be dependent on project economics, buyers' price sensitivity, and the relative competitive landscape. On the other hand, even limited US LNG export volumes indexed to Henry Hub will be sufficient to spark competitive pricing among existing and up-and-coming LNG suppliers. For Asia Pacific buyers, supply competition and diverse pricing approaches are welcome new developments.

Over the long term, it will be important to watch the development of domestic gas markets in key Asian countries to see when the next evolutionary step in Asia Pacific LNG pricing will be feasible – a regional gas hub index. Despite Singapore's goal, and to lesser extent, Shanghai's ambition, to serve as regional trading hubs, significant regulatory and infrastructure obstacles make the prospect of a regional gas hub index a long shot in the near-term.

# 3. Resource nationalism – entering a period of low tide?

## The quick read

- Resource nationalism will recede in the short-term as new resource-rich countries seek to attract investment and access technology.
- In the long-term, resource nationalism will rise as countries progress through the stages of resource development and gain technological expertise.
- Instead of an IOC versus NOC relationship, partnership strategies will be critical for both IOCs and NOCs to sustain long-term competitiveness.

Resource nationalism is a continuous challenge in the oil and gas industry, and follows an ebb and flow pattern. The recent discoveries of new resources and burgeoning demand in developing countries have produced a new crop of supply and demand centers, making industry players sensitive to a potential rise in resource nationalism. From the point of view of investors and global oil and gas companies, resource nationalism may seem to be an unmanageable risk, but as Joseph A. Stanislaw, independent senior advisor to the Deloitte member firm in the US, reminds us, from a government perspective, "resource nationalism is a legitimate right for sovereign countries. What matters is how it is applied."<sup>39</sup> Understanding what drives resource nationalism and how it is applied can help companies develop proactive strategies and approaches to manage potential risks, or cultivate opportunities.

We define resource nationalism through the types of government resource policies and fiscal regimes. A country's resource policy is either protective (no equity participation to low equity stakes in production sharing contracts), or open (concession contracts). The level of government fiscal take, which includes royalties, taxes, and signature bonuses, also defines the degree of resource nationalism in a country.

Typically, resource nationalism is portrayed as a challenge perpetuated by NOCs and their governments, and a risk to be managed by IOCs. By defining resource nationalism in terms of governments' resource policies and fiscal regimes, we elevate the discussion by showing how all governments exhibit degrees of resource nationalism. Moreover, our analysis highlights the partnership opportunities between IOCs and NOCs, moving beyond the adversarial aspects that colored IOC/NOC relationships in the past. Not only are we seeing beneficial, mutually dependent relationships between IOCs and NOCs, but NOCs themselves are playing a quasi-governmental role in terms of infrastructure development, and transference of technical expertise to smaller players in the value chain. This interplay has, in some cases, benefited IOC partners by deepening relationships in the countries where they operate, and better assist them to withstand resource policy changes.

Figure 3.1. Resource Nationalism Transitions for Major Oil and Gas Resource Countries



Changes in the degree of restrictive policies, or resource nationalism, are triggered by growth in production volume or prices; which in turn will prompt governments to capture a higher share of economic benefits from their country's resources.

For this reason, we see resource nationalism diminishing in the short-term until producing countries advance in resource development; bringing a rise in restrictive resource policies in the long-term. Figure 3.1 shows the transition of new and existing producing countries over the long-term.

### Muted resource nationalism in the short-term

The degree of resource nationalism will subside in the short-term due to three reasons:

1. Development of new resources in countries that have less nationalistic policies (US, Canada and Australia);
2. Significant resource potential in countries with limited technical manpower and experience (China, Brazil and Argentina); and
3. Traditional resource-rich countries overcoming falling production by exploring new frontiers or new resources (Russia, Libya and Nigeria).

The US, Canada and Australia are the new entrants on the list of resource-rich countries due to a gas boom from shale in North America and offshore and coal bed methane (CBM) in Australia. These countries will continue to be on oil and gas companies' radar, as they provide complete access to resources under concession contracts compared to restrictive production-sharing contracts (PSCs) and high government fiscal take in other resource-rich countries.

China, Argentina and Brazil will open their newly found resources to foreign oil and gas companies in order to access technology and technical expertise. China, for example, allowed foreign players to bid jointly with local companies in its second shale gas licensing round. And, although no foreign joint venture bids won, it is likely that there will still be foreign partnership opportunities as was the case after the first round of licensing.<sup>40</sup>

Similarly, Argentina's YPF signed a deal with Chevron and Bidas (50% owned by China National Offshore Oil Corp. (CNOOC)) to explore and develop shale resources within the country.<sup>41</sup> Brazil's national oil company, Petrobras, will initially require technical assistance from foreign companies for the development of its capital intensive pre-salt resources. The country softened its PSC terms to a minimum 30% NOC stake from the earlier levels of over 45%, but retained operatorship.<sup>42</sup>

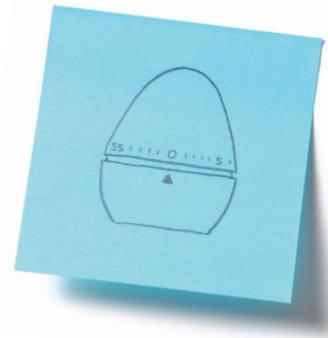
Russia, Libya and Nigeria will scout for foreign investment and expertise to reverse the declining rates of production. In Russia, with the traditional (West Siberian) oil producing fields in decline, the eastern fields (including offshore, Arctic, and Sakhalin), will be central to the country's continued oil and gas production expansion efforts. The recent collaboration of Rosneft and ExxonMobil to explore the Russian Arctic is just a starting point for softening resource nationalism in the country.<sup>43</sup> Russia also plans to open gas exports to multiple players, ending Gazprom's monopoly.<sup>44</sup>

Foreign capital and expertise will be key for Libya to return to sustainable output at pre-crisis levels or higher. Likewise, Nigeria's NOC (NNPC) will continue to rely on foreign companies to develop the needed infrastructure and learn the required technical skills for exploiting its massive offshore reserves.

### Re-emergence of resource nationalism in the long-term

Resource nationalism will increase and spread across regions due to three reasons:

1. Countries with new resources (US, Canada, Australia, China and Argentina) will progress through the stages of resource development;
2. NOCs (Russian, Brazilian, Nigerian and Libyan) will learn new technologies; and
3. Top resource-hub countries (Saudi Arabia and Qatar) will moderate the pace of resource development, while others (Kazakhstan, Iraq and Venezuela) continue to receive investments from resource-hungry NOCs (primarily Asian NOCs), despite tighter contract terms.



### **New resource development in the US, Canada, Australia, China and Argentina**

Countries without NOCs will likely increase government fiscal take, implement export restrictions, and/or tighten scrutiny of oil and gas M&A deals as demand for export volumes grows. However, the continued use of concession contracts keeps these countries on the lower end of the resource nationalism spectrum.

Despite growing supply and a dip in oil consumption, the US will continue to be a major crude oil demand center and maintain the ban on crude exports. On natural gas, the US will likely continue to allow LNG exports but with tighter scrutiny. The federal government may consider imposing export duties and limiting export capacity to evaluate the net benefit impact to the economy, and may also look at raising federal royalty rates to increase returns from shale gas. In January 2012, the US Interior Department proposed to increase onshore royalty rates from 12.5% to about 20%, but placed the proposal on hold due to low prices relative to international markets.

With the LNG boom, Australia will strengthen its position as a resource-hub, making a strong case for the government to gain by levying additional duties on its exports, as can already be seen with the extension of the petroleum resource rent tax (40% profit-based levy) to onshore projects in 2012.<sup>45</sup> Further, the government may also take cues from its other export-oriented sector, coal, where states increased mining rents up to 50% last year.<sup>46</sup>

Canada will likely follow the path of Australia and the US as it strengthens its position as a resource-hub. In 2012, Canada approved two major foreign acquisitions of domestic companies (Petronas-Progress Energy, CNOOC-Nexen) only after they cleared the “net benefit” test, but the Canadian government plans to increase its intervention in future acquisitions by foreign state-owned enterprises.<sup>47</sup>

NOC countries will likely change contracting terms to grab a higher share from their resources, as new technologies mature and infrastructure is built.

Argentina will likely transition from concession contracts to PSCs, considering the re-nationalization of YPF and growing energy demand. YPF is expected to increase its stake in future projects once it learns shale technology from foreign partners and builds the necessary midstream infrastructure in the country.

*“The new [foreign investment] rules mean future attempts by foreign state-owned companies to take control of a Canadian oil sands business will be approved only in ‘exceptional’ circumstances.”*

**Stephen Harper**, Prime Minister of Canada  
(December 7, 2012)

Energy security will continue to be a concern for China as its growing demand will maintain its status as a major demand center. China’s natural gas demand is expected to increase by more than 300% over the next 20 years, which will outweigh the expected supply growth from the country’s shale plays.<sup>48</sup> China’s PSCs already have provisions for the country’s NOCs to take a majority stake in the future. For example, CNOOC Ltd signed two PSCs with Chevron that allow the NOC to own a 51% stake in any commercial discoveries in the region, while all exploration expenditures will be borne by the foreign partner.<sup>49</sup>

### **NOCs in Russia, Brazil, Nigeria and Libya will gain technological expertise**

As frontier projects develop, Russia will strengthen its lead as a resource-hub and try to increase state ownership in these projects; as already seen with Sakhalin II, where Shell had to sell half of its 55% stake to Russia’s Gazprom in December 2006.<sup>50</sup> However, given the technical complexity and high risks associated with frontier operations, a return to this level of state control would only be likely over the long-term.

Brazil’s growing energy demand will keep it in the hybrid category of a demand and resource center, driving adoption of tighter policies to secure domestic resources. Increased development of pre-salt projects will support Petrobras’ cash flow and boost its ability to take control of future projects.

Nigeria and Libya will continue to have lower NOC stakes in their PSCs, given their limited technological expertise in offshore projects and desire to grow exports to support their ailing economies. In the long-term, both countries will attempt to capture a larger share of domestic resource output as the economy grows and regional NOCs learn offshore technology.

### Other major resource-hubs will maintain their current positions

Saudi Arabia is expected to retain its protective stance primarily due to its large and low-risk base of proven and conventional resources, strong NOC (Saudi Aramco) financial and technology capabilities, and limited supply growth opportunity given OPEC's quota restriction. Further, with an existing cushion of about two million barrels per day of additional oil production capacity, the country can easily support its production growth target of 1.2%.<sup>51</sup>

Qatar's National Vision 2030 hints at curtailing the pace of the country's resource development, which it views as a "great expansion" that could deplete its resources if left uncontrolled. However, lack of technological expertise and the need for large capital investments in Qatari LNG and gas-to-liquids projects will limit the tightening of resource policies.

In Kazakhstan, increasing financial support from Asian firms is sustaining investments at a time when IOC partners are exiting due to less profitable terms. India's ONGC Videsh took over ConocoPhillips' 8.4% stake in the North Caspian Kashagan field for \$5 billion.<sup>52</sup> Chinese energy companies invested \$14 billion in Kazakhstan during 2005-2012 and CNPC along with the Export Import Bank of China loaned KazMunaiGas \$10 billion in 2009.<sup>53,54</sup>

Iraq will likely maintain its current stance of using technical service agreements for developing fields, given the increasing interests of Asian NOCs. In another fiscal regime, Venezuela follows a PSC approach with 60% for PDVSA and 40% limited to foreign NOCs only, such as Rosneft which is partnering to develop the heavy oil deposits in the Orinoco belt.<sup>55</sup> With a large reserve base exceeding 200 billion barrels, Venezuela might be able to take an even larger share and still attract investment from the resource-hungry NOCs of Latin America and Asia.

### Our view

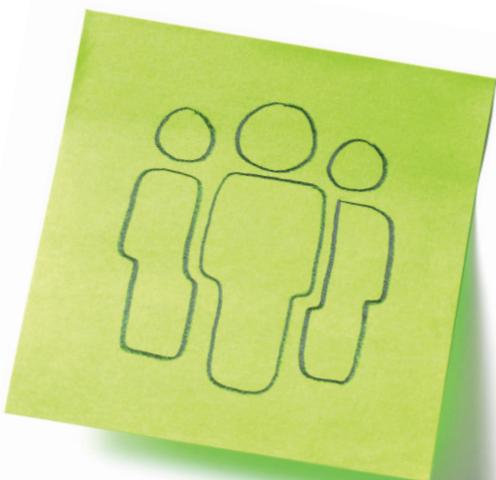
The global oil and gas industry is going through a phase of renewal with the entrance of new producing countries and traditional producing countries exploiting new, unconventional and frontier ventures. The associated high capital intensity, technical challenges, risks and uncertainties require partnerships, investments and experimentation. During this short-term phase, governments of producing countries are trending towards relative openness within their established resource policy models and fiscal regimes. As production and technical expertise progresses, governments will likely exert greater control over their resources for economic and strategic reasons, bringing a resurgence in resource nationalism in the long-term.

The US, Canada and Australia, leading development of unconventional oil and gas resources, continue with concession contracts and a stable taxation regime in the near-term, but are already indicating a future direction of restrictions on exports and foreign direct ownership.

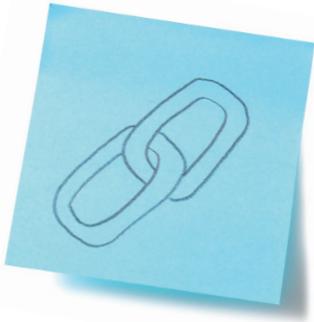
China, Argentina, and Brazil seek foreign partnerships to support development of newly found resources, balanced with the need to build local technical capacity and capabilities. The countries will likely change contracting terms to extract a higher share from their resources, as new technologies mature and infrastructure is built.

Traditionally dominant producing countries, such as Russia, Libya, and Nigeria will seek foreign investment and expertise to reverse declining rates of production in the short-term, but they will likely shift towards majority government ownership as economic production and cash flow improves in the long-term.

Resource nationalism affects both IOCs and NOCs, but in different ways. IOCs must balance partnership opportunities with potential policy changes in the countries they are operating in, or NOCs they are partnering with. As technology and technical expertise are major factors shaping resource policies, IOCs will need to continue to innovate. NOCs are increasingly encouraged to play quasi-governmental roles, but must balance these requirements with market expectations. For both IOCs and NOCs, partnership strategies are paramount to thrive in the ebb and flow of resource nationalism.

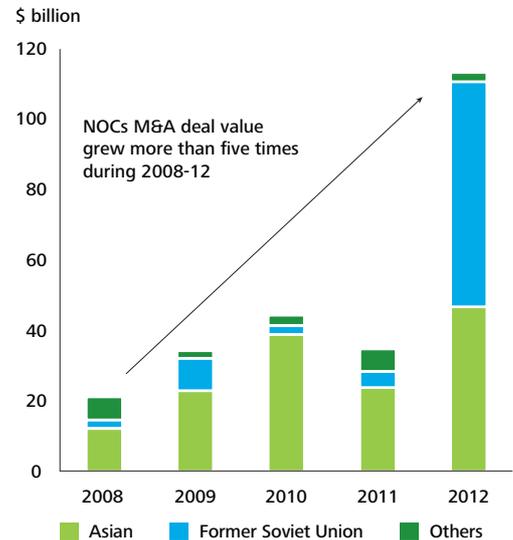


# 4. NOCs – capturing the playing field



The rise of National Oil Companies (NOCs) as a competitor to International Oil Companies (IOCs) is a persistent narrative. Trends in Exploration and Production (E&P) M&A show that NOC acquisitions reached an all-time high of \$112.6 billion in 2012, representing 225% year-on-year growth, and constituting 45% of total E&P M&A by value (see Figure 4.1).<sup>56</sup> The global expansion of NOCs and implications to their IOC peers are more nuanced than the overriding notion that NOCs are relentlessly buying barrels and acreage for supply security, squeezing IOCs out of the game. Instead, NOCs are taking larger risks by buying undeveloped acreage and fields, and initiating large acquisitions in emerging territories (US, Canada and Mozambique), showing that NOCs' are taking the long view and globally expanding for local resource development and technical capacity building.

**Figure 4.1 NOC Global M&A Activity by Deal Value**



Source: PLS M&A Database (January 2013)

## The quick read

- NOCs are evolving their global expansion by competing for complex barrels.
- Oil is the immediate need and gas is the future fuel for NOCs.
- NOCs will extend their investment and strategic focus to offshore and unconventional gas, closing the competitive gap with IOCs.

A deeper look shows that NOC expansion is differentiated by oil versus gas. Oil has been the predominant target of investment and E&P efforts, but this will shift to gas in the long-term due to changes in end use demand, resource availability, and price.

Understanding how NOC expansion is differentiated by oil versus gas will help define how IOCs and NOCs compete and collaborate.

### Oil on NOCs' agenda in the short-term

NOCs' global acquisition and expansion has primarily focused on oil over gas due to oil's higher demand and premium price advantage. In 2012, over 60% of NOCs' M&A deals by count and value were for oil-heavy assets showing a primary focus on oil rather than gas.<sup>57</sup>

In terms of demand, NOCs' immediate priority is to secure oil supplies as their economies are heavily oil-dependent for both exports and imports. On the export side, 80% of Saudi Arabia's budget revenues are dependent on the petroleum sector. On the import side, China, India, Thailand and South Korea import 70% of their oil consumption and own only 9% of their oil imports in overseas equity.<sup>58</sup>

The sustained premium of oil prices to gas prices in MMBtu terms, which is 4:1 for WTI crude to Henry Hub gas, and 1.5:1 for Brent crude to NBP gas, strengthens the case for both export-oriented and import-dependent NOCs to focus investments in oil rather than gas.

More importantly, NOCs are evolving from producing easy barrels (i.e. onshore conventionals) to complex barrels (i.e. offshore and unconventional), and investing in technical service capabilities.

In the past, NOCs partnered with IOCs which took operator roles and provided technical services. NOCs are now investing in developing in-house oilfield services (OFS) subsidiaries, such as Sinopec's new OFS arm, Sinopec Oilfield Service Corp., which has already won 480 contracts worth \$14.2 billion in 43 countries. Innovation is also a major component of NOCs' strategies which can be seen in R&D spend rates where the major NOCs are outspending IOCs by 25% (see Figure 4.2).<sup>59</sup>

In unconventional oil, NOCs are using a mixture of partnership and acquisition strategies to develop heavy oil, oil sands, and shale oil resources.

In heavy oil, for the development of its massive Orinoco belt, Venezuela's PDVSA is interested in allying only NOCs, primarily Russian NOCs (e.g. Rosneft) and NOCs from the Union of South American Countries (UNASUR).

**Figure 4.2. R&D Investments by Company Type (2011)**

O&G Major Type	R&D Investment (\$ billion)	R&D Investment % of Sales
NOCs	\$5.60	0.51%
IOCs	\$4.50	0.26%
OFS	\$2.30	2.10%

Source: FactSet

NOCs have taken notice of Canada's oil sands production and pursuit of export markets other than the US, leading to major deals such as CNOOC's acquisition of Nexen for \$15 billion, a premium of 60% over Nexen's closing price at the time of announcement.

In shale/tight oil, NOCs' participation will accelerate as cash-strapped US E&P companies need capital to develop their acreages, which are under use-or-lose contract terms. However, NOCs' participation will be limited to forming JVs and learning the technology, rather than big corporate buyouts, as they cannot take or export oil out of the US.

For frontier exploration, the Russian NOC, Rosneft, plans to explore Arctic oil reserves in partnership with IOCs, but will likely retain the majority stake while seeking interests in IOCs' proved oil projects. This dynamic was recently demonstrated when Rosneft acquired interests in ExxonMobil's profitable US operations in exchange for the IOC's partnering in the Arctic project.

#### NOCs upping their game in gas for the long-term

NOCs will transition from a learner-cum-partner to a competitor position in the gas sector, particularly in shale and LNG, as technology matures and demand increases across all end-use sectors (residential, power, industrial, and transportation). As an example of demand increase in gas, China plans to double the share of natural gas in its total energy consumption to 10% by 2020.<sup>60</sup>

Offshore gas projects compared to onshore gas projects have been challenging for NOCs due to higher infrastructure needs, longer gestation periods, and technical constraints. Despite these challenges, NOCs are increasing investment in offshore gas projects, such as in East Africa. The region, which holds over 400 Tcf of offshore reserves with the potential of \$7/MMBtu LNG break-even price, could possibly emerge as a top LNG exporter.<sup>61,62</sup> NOCs' interest in the region's offshore plays is evident in the premium bidding prices, such as Thailand's PTTEP topping Shell's \$1.57 billion bid to acquire Cove Energy for \$1.77 billion, further raising its offer to \$1.90 billion.<sup>63</sup>

The shale gas boom in North America attracted both IOCs and NOCs. IOCs entered early and suffered price risk challenges, reflected in their ongoing write-offs of shale reserves due to the steep fall in natural gas prices. For example, BP wrote down US shale gas acreage by \$2.1 billion in 2Q12.<sup>64</sup> Asian NOCs are entering into JVs with independents at favorable valuations, as can be seen when Sinopec formed a \$2.2 billion JV with Devon in 2012 by paying less than \$5,500 per acre – this contrasts considerably with Total paying \$15,000 per acre for its JV with Chesapeake in 2011.<sup>65</sup>

Asian NOCs are entering the North American shale market primarily to learn and apply shale gas technology to their domestic markets. Initially, NOCs will partner with IOCs in their domestic market but may face diminished opportunities in the long-term as shale technology and knowledge transfer matures. OFS majors are quickening the pace of IOCs' diminished opportunities by moving deeper into NOC markets and entering into strategic alliances with local OFS firms, such as Schlumberger's 20% stake in China's Anton Oilfield Services Group.<sup>66,67</sup>

NOCs will likely defer the development of Arctic gas reserves due to high costs and an abundance of economically recoverable shale gas. Gazprom chose this route and indefinitely postponed the development of its Shtokman project in the Arctic.

#### Our view

The global expansion of NOCs is not a new story, but the fact that expansion strategies differ between oil and gas is a recent and important development. NOCs have evolved from players focused on production in domestic oil resources to become interested in more complex barrels in unconventional oil. The NOCs from energy-hungry, developing countries, such as China and Brazil, are also transitioning from being passive partners of IOCs seeking supply security, and are becoming technical leaders in riskier plays.

In the short-term, NOCs will continue to dominate production in the conventional oil sector, and in the long-term they will increase investments in the gas sector, especially in offshore gas, shale gas, and LNG.

Not only do these developments impact IOCs, but also OFS majors who are emerging as important partners for NOCs, even as some NOCs are starting their own OFS subsidiaries. Overall, the industry will benefit as NOCs continue to invest heavily in R&D, expand in services capability, and transfer technical expertise to local development of resources.



# 5. Managing market complexity – revolution of the play, evolution of the player



It is no secret that, over recent years, oil and gas companies have been forced into ever more challenging operating environments and become subject to ever more volatile and complex market conditions. As discussed throughout this report, the entire industry is in flux. The US shale gas revolution has captured the world's imagination, prompting country after country to try and spark similar energy revolutions of their own. Gas exports from the US and other countries to Asia Pacific will create the competitive conditions to challenge the predominance of oil-indexed prices in LNG long-term contracts. Resource nationalism will ebb and flow as countries advance through the stages of resource development. The global expansion of NOCs to secure supply and technical expertise is altering the playing field.

Sections three and four of this report showed the importance of analyzing how industry trends and outlooks differ between the oil and gas sectors. This is mostly due to the varying levels of maturity in oil and gas E&P, price differentials, and changes in the magnitude and mixture of demand. The types of business models employed by oil and gas companies also differ between the sectors. The gas sector, which is dominated by growth in unconventional and LNG, is facing greater vertical integration, while the oil sector is undergoing dis-integration and specialization for smaller players.

### Greater integration in gas

The gas sector is undergoing fundamental change with the exploration and development of unconventional gas and expansion in LNG trading. Taken together, the high capital intensity, technical innovations, and the need for supply security, create the conditions for tighter integration in terms of multiple partnerships and value chain expansion, as well as non-traditional companies evolving into key roles in upstream and midstream segments.

The E&P dynamics of unconventional gas are vastly different from oil and conventional gas, and are often compared to a manufacturing process. The application of trial-and-error techniques and technologies, greater number of wells drilled, and the lower risk of resource certainty, places operational focus on improving above ground efficiencies, such as asset utilization rates, inventory management, and supply chain management. This emphasis on improving per unit costs and standardizing the "gas manufacturing" process requires a network of partners, namely E&P companies and service companies specializing in not only geophysical and drilling services, but also water and wastewater treatment, among other services.

### The quick read

- Global oil and gas market conditions have become more varied and complex, redefining "business as usual".
- There is greater integration in the gas sector, and dis-integration in the oil sector.
- The entrance of non-traditional players and diverse business models will be the new normal.

These supply, demand and macro environmental factors illustrate the high degree of market complexity that renders the term "business as usual" obsolete (see Figure 5.1). Vertical integration was traditionally seen as the "winning" business model, but the industry has become more fractured with diverse business models and non-traditional players debunking the notion of a singular "winning" business model.

Figure 5.1 Market Complexity Drives Diversity in "Winning" Oil and Gas Business Models



LNG projects, which are also capital intensive with deployment of innovative technologies, is another area with changing business models characterized by a high number of non-traditional oil and gas companies and greater vertical integration.

Non-traditional oil and gas companies that are entering the LNG market include utility companies, banks, and trading companies. Twenty-four of these types of companies are shareholders in existing or planned LNG export projects, and hold about 8% of total export capacity. While this may seem to be a negligible number and non-traditional players are not a new phenomenon, what is significant now is the higher percentage of ownership for projects under construction or planned/proposed status, indicating future growth. Mitsui and Mitsubishi are the most notable of the non-traditional players investing in LNG projects. Having previously invested in small stakes (less than 5%) for financial gain, the companies are increasing their investments and are even acquiring controlling stakes; as recently seen in Mitsubishi's final investment decision in Indonesia's Donggi Senoro LNG project.<sup>68</sup>

The position of these non-traditional players in the LNG value chain highlights the trend of vertical integration for the gas sector. Korean and Japanese utility companies are moving further upstream, taking equity stakes in E&P gas projects. These non-traditional players in the upstream and midstream segments are providing project partnerships with vital financing and the critical needs of a stable demand market.

Supermajor and major integrated oil and gas companies are also taking advantage of market conditions to further integrate along the gas value chain. Key enablers for vertical integration in the gas sector include diverse, abundant gas resources, demand growth, and the need for transportation/infrastructure capacity improvement. Other significant developments in the LNG market, such as flexible contracting terms and changing pricing approaches, create favorable conditions for major integrated companies with the scale to exploit cost inefficiencies and price disparities.

Major integrated companies who have diverse gas basins and LNG liquification capacity are able to employ a "portfolio contract strategy" – the optimization of marketing by matching supply and demand on volume, time, cost and/or distance terms. This can benefit the buyer in terms of lower costs through hybrid indexation, as a portion of LNG could be sourced from a gas hub market (e.g. North America), and another portion sourced from a market that prices to oil benchmarks.

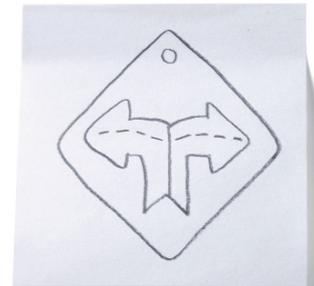
Vertical integration is also occurring in the LNG tanker segment. Stable access to tanker capacity is a major advantage where shortages in tanker capacity drove up charter rates to an average of \$141,000 a day in 2012, compared to \$92,000 in 2011<sup>69</sup>. One supermajor has a shipping subsidiary and equity fleet to control costs and schedule, and to engage in spot trading and arbitrage opportunities. Mitsui has an equity fleet of five tankers ranging from 10-34% in ownership stakes, showing again how non-traditional players are moving up the value chain.<sup>70</sup>

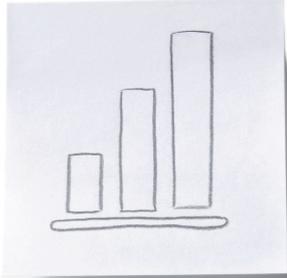
### Greater dis-integration in oil

The US petroleum market is the hotbed of the increasing trend of dis-integration. With declining petroleum consumption in the US and high crude oil prices, refining margins are squeezed more than ever, while upstream spending and production surges. In the past two years, four integrated companies announced or completed spin-offs of their downstream businesses. Although stock market and analyst reactions to the spin-offs have been mixed, at least one general consensus can be concluded – there is uncertainty in the value of the integrated model for oil companies.

The integrated oil companies that have divested their downstream segment have all cited the need to focus on disparate strategies as the major reason. Not all integrated oil companies are heading down the same path of dis-integration, but some are rationalizing downstream assets. In this year's annual results, ExxonMobil and Chevron have seen profits increase due to international downstream asset sales and growth in their chemicals businesses. What this counter-example shows is that the integrated business model works well in large economies of scale, and this model also works when the portfolio is heavy on global upstream assets, as is the case for the supermajors.

The integrated model also fits for NOCs facing their home markets' rising demand and government incentives for refinery output. Although subsidized retail prices hurt their refining margins, NOCs generally face less pressure to achieve returns, unlike their IOC peers. Expansions in refinery capacity are localized to key demand centers, such as China, but they hold partnership opportunities for supermajors (such as ExxonMobil, Shell and Total), that are expanding their global integration. Aside from refinery capacity, there is substantial global growth in petrochemicals capacity, where 90% of growth is driven from the Middle East, China, and India, and partnerships in these regions are on the rise for both NOCs and supermajors.





#### Our view

The examples of how US medium-size integrated companies, supermajors, and NOCs have evolved show that vertical integration as the winning business model in the oil sector is far from becoming a market certainty. Instead, vertical integration largely depends on aligning company strengths and strategy with local and global market conditions.

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In the gas sector, marked by growth in unconventional resources and LNG, the entrance of non-traditional players, downstream players moving upstream, and large integrated companies expanding throughout the value chain, seems to show that vertical integration is the winning business model.

In the gas sector, marked by growth in unconventional resources and LNG, the entrance of non-traditional players, downstream players moving upstream, and large integrated companies expanding throughout the value chain, seems to show that vertical integration is the winning business model. Similarly with the oil sector, vertical integration works for companies with significant economies of scale especially considering the high capital intensity for unconventional E&P and LNG projects.

This report's previous sections detail the changing dynamics in supply, demand and macroeconomic factors. New suppliers enter the market, countries shift their resource policies in line with production maturity, and NOCs and IOCs forge deeper partnerships. Closer examination of these trends shows differences in the oil sector versus gas sector. This sector difference is mostly due to the disparate level of maturity in oil and gas E&P, price differentials, and changes in the magnitude and mixture of demand.

Overall, the industry has evolved where market complexity is best managed through diversification of companies, partnerships, and flexible business models.

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# Notes

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