ACCESS TO GAS—REVISITING THE LNG INDUSTRY’S BIG CHALLENGE

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ABSTRACT

The need for additional gas reserves to feed LNG liquefaction plants remains huge, partly because of forecast LNG demand growth of 4.5% per annum out to 2025, but also because the reserves feeding several large, legacy LNG projects are heading into decline.

However, accessing this gas is arguably more challenging than ever. Many major gas resource holding countries now have such strong domestic demand for gas, that reserves can no longer be made available to support exports – from new, and in some cases existing, facilities. A wave of gas-focused exploration, from Australasia to East Africa to the Levant, has added significant new reserves, but as always, turning this gas into LNG remains challenging for a combination of commercial, technical and political reasons.

In North America, the shale gas revolution has created the potential for significant LNG exports, but securing the gas for LNG is proving far from straightforward. Unconventional gas activity further afield also offers the tantalising possibility of gas to support LNG exports from some existing as well as new countries.

In this paper Wood Mackenzie reviews the industry’s options for accessing gas feedstock and considers the challenges and attractions of each. Along the way, we revisit our papers from LNG15 and LNG16, where respectively we considered: the challenges associated with accessing NOC controlled gas reserves and their impact on gas focussed exploration, and the opportunities presented by unconventional gas, to see how these trends have evolved.

INTRODUCTION

LNG demand is expected to grow very significantly, from 240 mtpa in 2012 to a forecast 440 mtpa in 2025, and a lot of additional LNG supply will be required in order to meet that demand. However, supply doesn’t have to increase just to satisfy this incremental demand growth, it also has to replace lost supply from a number of existing LNG supply projects where production is going into decline, either due to depleting reserves or diversion of those reserves to meet demand from local gas markets.

As a result, huge volumes of additional gas will have to be accessed and developed in order to provide the feedgas for this additional LNG supply. There are three main options for securing this gas: exploiting already discovered conventional resources, exploring for additional conventional resources and/or developing unconventional resources. However, each option has its challenges, typically a mixture of technical, political and/or economic factors.

In our paper at LNG15 we looked at the challenges that the IOCs involved in LNG faced in accessing discovered conventional gas resources, which at the time were largely controlled by the NOCs, and forecast that they would lead to more gas-focused exploration to support LNG projects. That forecast proved correct as evidenced by inter alia the very significant volumes of gas that have been discovered offshore East Africa, in the Levantine Basin, and the continued exploration activity offshore Australia.
In our paper at LNG16, we asked whether LNG supply had an unconventional future given the rush to feed coal-seam gas (CSG) into LNG plants in Queensland, Australia, the proposals to export shale gas from Western Canada and Chesapeake’s initial musings about the possibility of exporting shale gas as LNG from the US Gulf coast. Now, three years later, there are three large CSG to LNG projects under construction in Queensland, the US Gulf coast has leap-frogged Canada with the first two trains of Cheniere’s 18 mtpa export project at Sabine Pass in Louisiana already under construction, and over 200 mtpa of additional LNG export capacity is now proposed in the US and Canada fed primarily with unconventional gas.

So in re-assessing the options that the industry has to access the gas needed to underpin new LNG supply (and the associated challenges), we revisit the themes of our LNG15 and LNG16 papers and look at the role of exploration vs. discovered resource exploitation and the balance of conventional vs. unconventional gas, particularly in light of the industry’s focus on unconventional resources. In doing so, we also consider the approaches taken by different players within the industry and identify some other factors that need to be taken into account by project developers.

**FRAMING THE CHALLENGE**

In order to assess the scale of the challenge that the industry faces we have made an estimate of how much extra gas feedstock will be required to support the additional LNG production needed to meet demand growth as well as to replace declining production from existing LNG plants. Figure 1 highlights how much additional LNG capacity will have to be developed, over and above existing capacity that is expected to still be in operation in 2025 plus capacity already in construction (which is assumed to be backed by adequate feedgas).

![Figure 1: Additional LNG Requirement for 2025](source: Wood Mackenzie)

In 2025, we expect the world to require an additional ~160 mtpa of LNG, which in turn will require ~8.5 tcf of gas feedstock per year. This means that LNG projects backed by approximately 175¹ tcf of gas reserves will need to have been brought online by 2025. Some of this LNG will actually be required earlier, in order to meet demand for LNG at the end of this decade and the start of the next, while beyond 2025 the gap will continue to widen as existing supply declines and demand growth continues. There are three main areas where these new reserves could potentially come from; already discovered conventional resources; future exploration; and/or unconventional resources.

¹ Assuming 1 mtpa of LNG capacity producing for a typical 20 year period requires 1.1 tcf of feedstock
We would also highlight production problems as a key risk to our operational forecast in 2025. The LNG industry involves a complex supply chain and operates in many challenging parts of the world, which could result in supply not meeting expectations. Key risks to operational LNG supply include:

- Growth in domestic markets which could cause a reduction in the amount of gas being made available to support LNG exports as the domestic market is prioritised;
- Reserve downgrades; and
- Unexpected shut-downs or capacity reductions due to operational issues, insurgency, war or natural disasters.

These potential issues mean that our assessment of the contribution of existing operational capacity in 2025 could be overstated, creating an even greater need for additional gas reserves. Indeed, as illustrated by Figure 2, if we compare our forecast of 2012 supply from existing operational capacity back in 2007 (at the time of LNG15) with the actual contribution in 2012 from that same capacity, we can see it was 35 mtpa less than expected. This was primarily due to growth in domestic demand for gas in Algeria, Egypt and Indonesia and the failure to incentivise enough domestic gas reserves to be developed to meet both domestic demand and export commitments in these countries.

![Figure 2: Comparison of Forecast vs. Actual Production from Existing Liquefaction Capacity in 2012 (2007 vs. 2012)](image)

**THE CHANGING RESOURCE BASE**

So having established that by 2025 the industry will require at least an additional 175 tcf of feedgas to underpin the new LNG capacity required to meet forecast demand, we now take a step back and look at how the gas resource base has changed since LNG15. This will provide some additional context for assessing the options available in terms of accessing that gas to develop as LNG supply.
Figures 3 and 4 show how the overall gas resource base has changed from 2007 to 2012, both in absolute terms and the conventional vs. unconventional split. We estimate that in the last five years, global gas resources have risen from nearly 5,000 tcf to nearly 8,000 tcf. This is an increase of ~60% from 2007 levels and is on top of the gas that the world has consumed in that period.

The main growth has been the rise of unconventional resources, which have added around 1,700 tcf to global gas resources. 2007 was the first year that the Energy Information Administration (EIA) in the United States reported shale gas and coal bed methane (CBM) as separate line items in its yearly reserve report. It estimated 44 tcf attributable to these resources in that year, whereas Wood Mackenzie now estimates North American unconventional gas resources of around 1,600 tcf mainly in shale formations. While the rest of the world has been slower to catch onto the potential of unconventional gas, Australia and Argentina in particular have also added significant resources (Figure 5) and we expect unconventional gas reserve growth in inter alia China, Eastern Europe and parts of Africa.
The growth in the discovered conventional resource base has been driven by exploration and the huge upgrade in reserves announced in Turkmenistan. Figure 6 shows exploration additions since 2007. There has been a marked upturn in gas discoveries over the last three years, with East Africa, the East Mediterranean and Iran being responsible for much of the recent growth. The majority of recent exploration success has also been concentrated in the hands of IOCs, which is set to have some interesting consequences for the LNG market as discussed subsequently.

![Figure 6: Conventional Gas Resource Additions via Exploration (2007 to H1 2012)](image)

The discoveries in these regions are important for the LNG industry as they are generally distant from major demand centres and therefore LNG is the primary monetisation option. East Africa, in particular Mozambique, is perhaps the most eye catching of these. Joint ventures led by Eni and Anadarko have discovered over 100 tcf during the last three years and the outlook for further discoveries and reserve upgrades is high. Plans for LNG development in Mozambique are in their infancy but a jointly owned multi train LNG facility is likely to be added over the next two decades.

In the East Mediterranean, Noble, in partnership with Israeli companies, has made three large gas discoveries in Israel and Cyprus, and in Australia exploration success has continued in the Carnarvon and Browse basin. Hess, ConocoPhillips and Chevron have all enjoyed success with a string of significant discoveries.

The other major resource addition since 2007 has been the upgrade in reserves at South Iolotan in Turkmenistan, announced between 2008 and 2011. Resources for the field are highly uncertain, but Wood Mackenzie makes a conservative estimate that South Iolotan resources are around 200 tcf, virtually all of which has been added over the last five years.

Figures 7 and 8 show how the balance of the discovered conventional gas resource base has changed from 2007 to 2012.
Overall the balance of reserves has not shifted much at all. However the exploration success that IOCs have enjoyed has mainly been in new geographic provinces where there is little, if any NOC control, whereas the major NOC reserve additions in Turkmenistan and Iran remain largely stranded. This means that IOCs are now less reliant on negotiating with NOCs for access to gas reserves as there are other potentially easier to access discovered resource options available for them to develop, both in the conventional and unconventional space.

In conclusion the resource base has grown massively over the last five years, mainly as a result of the rise of unconventional gas, but also as a result of recent exploration success. Therefore we now turn our attention to considering how the industry is likely to utilise these various alternative sources of gas to support growth in LNG supply capacity.

THE OPTIONS FOR ACCESSING GAS

In this section we compare the different options that the industry has for accessing the gas required to support the development of the additional LNG capacity required and, for each option, describe what has happened in recent years and what the challenges are likely to be going forward.

UNCONVENTIONAL

In our LNG16 paper we forecast that 7% of global LNG supply would come from unconventional sources by 2020. However, three years later that forecast is now 20% - why is this?

Australian CSG has seen the greatest level of LNG development activity. There are now three CSG LNG plants with a combined capacity of 25 mtpa under construction on Curtis Island in Queensland, having successfully overcome challenges associated with disposal of produced water, and buyer concerns about reserve certification, ramp-up gas production and low calorific value LNG. However, worse than expected upstream results in Queensland; higher costs, in part a consequence of the level of local development activity; and landholder pressures have presented new challenges to project developers. As a result the return on investment on these projects will likely be significantly lower than that anticipated at project sanction and more unconventional gas, this time shale gas, may be required to backfill local markets and cover LNG export project shortfalls. Although expansions to plants presently under construction and new
plants are proposed, both buyers and developers are wary of additional Queensland CSG LNG capacity until confidence returns that the current challenges can be overcome, with deliverability and commerciality ensured. Consequently there is a hiatus in Queensland CSG LNG development and indeed the additional capacity, when it is added, will likely ultimately be more modest than we had expected at LNG16.

The growth of the shale gas resource in North America, along with technology improvements that have brought down well costs while increasing productivity, have driven the outlook for global LNG fed by unconventional gas. At under US$2/mmbtu at times, the price of Henry Hub gas in the US in 2012 was at its lowest for 10 years. In addition, the US Gulf and East coasts have some 120 mtph of existing regasification import capacity capable of conversion to liquefaction at up to 50% less capital cost than a greenfield LNG project.

However, despite US Department of Energy (DOE) reports suggesting significant trade benefits, some groups, particularly industrial customers, have opposed exports on the grounds that they will raise US gas prices. The political argument has caused delays to export approvals which have contributed to a slow pace of US LNG development with only two trains at Cheniere’s Sabine Pass taking final investment decision so far.

Rising domestic gas prices will limit the commerciality of exporting US gas as LNG. While LNG exports will contribute to these price increases, rising domestic demand unrelated to LNG exports will contribute far more. Also, it is increasingly likely that construction costs of subsequent LNG projects will rise, a consequence of a number of factors including local competition for materials and labour associated with multiple downstream developments - ammonia, ethylene, methanol, refining and GTL in addition to LNG. The combined impact of rising feedgas prices and higher LNG development costs will likely restrict the volumes of US LNG export capacity developed. Nevertheless we anticipate more US LNG projects will be developed, likely a further 8 trains before 2020.

The challenges for Canadian LNG exports are different from those in the US. The focus has been on developing the vast shale gas reserves in British Columbia and Alberta in western Canada, historically a supply source for the US but which is now looking increasingly stranded. In western Canada, not only do developers need to build a greenfield liquefaction facility and port infrastructure in a remote location, they also have to develop a pipeline of up to 800km in length across the Canadian Rockies to link the gas resource to the liquefaction plant. In addition to difficult terrain, environmental challenges and high costs, cooperation from First Nations and other local stakeholder groups are essential if project ambitions are to be achieved. Also Canadian LNG projects will compete for limited resources with the growing oil sands industry in western Canada, contributing to cost and project schedule uncertainty. Five LNG export projects are presently proposed, each using its own dedicated pipeline infrastructure. It is likely that project consolidation and collaboration will ensue, particularly if LNG developers are to learn lessons from the experience of Australian CSG LNG.

Unconventional gas development outside Australia and North America has been slow. The reasons are multiple and well documented elsewhere. In time the global unconventional gas resource will be exploited but the volumes of unconventional gas that are developed for LNG will likely be restricted by government policy. In Argentina, for instance, the unconventional gas reserve base appears more than sufficient to sustain domestic demand but government policy is likely to restrict gas exports. An LNG export debate in Argentina is likely to be shorter than that seen in the US with the Argentinian government more likely to prioritise low domestic gas prices over trade benefits. A similar policy may be anticipated in other countries such as China and elsewhere as unconventional gas development for local markets, including industry, presents a potential political lever.

While new unconventional gas exporters may yet emerge, unconventional gas for LNG exports will be easier to substantiate in those countries that have a successful history of gas exports and declining production from conventional gas, particularly those likely to have existing under-utilised LNG infrastructure and/or an existing local market which encourages its initial development. Indeed Indonesia’s Bontang LNG facility is already liquefying and exporting CSG and can claim to be the world’s first unconventional gas LNG exporter. While volumes to date have been small, the potential exists to exploit local proximate gas through existing
infrastructure at relatively low marginal cost. Unconventional gas elsewhere including tight gas in Oman and shale gas in Algeria could be similarly developed. However, in all instances an appropriate regulatory environment will be essential to successfully and commercially exploit the reserves.

Unconventional gas for LNG is an increasingly exciting development opportunity for the industry, although local issues may restrict its ultimate contribution. Also events such as those in Eastern Australian CSG have confirmed the views of some buyers that, given the emerging nature of the opportunity, unconventional gas into LNG is best approached incrementally. Consequently unconventional LNG offers an opportunity that sits alongside other more established LNG opportunities rather than one that supplants them.

**CONVENTIONAL**

**Exploration**

Conventional gas exploration has been a massive success since LNG16 with more gas added in each of the last 3 years than in the preceding 10 years. East Africa stands out as the greatest gas exploration success story where over 125 tcf of gas has been added in Mozambique and Tanzania since 2010 (Figure 6). In the Rovuma Basin, northern Mozambique, over 100 tcf has been discovered. Further north, in Tanzania, where the targets have been the northern extension of the Rovuma Basin and the Mafia Basin, over 25 tcf of gas reserves have been added. The Levant basin in the East Mediterranean has added around 40 tcf of gas reserves since 2009, mostly in Israel but also in Cyprus. By contrast the prolific basins offshore western Australia have yielded less than 30 tcf through exploration since 2008. There now exists the potential for East Africa and the East Mediterranean to become major LNG suppliers.

Exploration success since LNG16, particularly in new basins, has been driven by the independents. But with exploration returning full cycle IRRs in excess of 15% over the last 10 years, exploration is now attracting the interest of super-majors. As a result the global exploration budget is likely to grow to grow from US$87bn in 2012 to as much as US$100bn in 2013/14. This exploration will have an enormous geographical spread and more gas reserves will be added. Areas which have already seen success such as East Africa and the East Mediterranean will be a focus with drilling expanded into adjoining territories including Kenya and Lebanon respectively. Some regions such as West Africa and Latin America will receive a disproportionate share of drilling budgets as the focus of exploration will be on liquids, but gas reserve additions will be inevitable. However, while exploration activity and reserve additions are likely to remain high, the commerciality of this exploration, particularly gas, is less certain given the increasingly competitive LNG supply environment

Some gas explorers may seek to focus efforts in basins proximate to existing LNG infrastructure. However, recent such efforts have met with limited success. While western Australia and Indonesia have seen limited returns on the extensive exploration drilling undertaken since LNG16, average value creation through exploration drilling in eastern Malaysia may yet prove to be more successful.

The greatest gas exploration successes have been in frontier areas and in deepwater, typically in water depths greater than 1,000 m, with high well costs, typically greater than US$100m. Faced with such high costs and a binary environment of either LNG sales or stay-in-the-ground, some companies may see onshore unconventional gas as a lower-risk option if a local market presents an alternative commercialisation route to LNG.

Addressing the needs of potential buyers to ensure product differentiation will be increasingly important. For example, gas reserves added recently through exploration have been increasingly dry. Legacy LNG supply, from Brunei, Indonesia, Malaysia and North West Shelf in Australia was rich, much of it associated with liquids production. But the more recent slate of LNG developments, including that from Australia, have typically been of a leaner specification. US LNG is lean and gas added through exploration in East Africa and East Mediterranean is also lean. While many buyers are having to adjust to this drier gas, LNG projects with a richer product may be able to attract a premium price in the market.
EXPLOITATION OF DISCOVERED RESOURCE

As we have already noted in Figures 3 and 4, global gas resources have increased by 60% or nearly 3,000 tcf since LNG15, to around 7,800 tcf. This has been through the growth in unconventional gas resource and successful exploration.

NOCs continue to control most of the world’s gas resource and remain key to exploiting discovered resource opportunities. However, typical NOC resource holder terms for gas development, as for oil, remain tough. At the same time the cost of gas developments has grown, *ceteris paribus*, while the technical complexity of developing much of this NOC controlled gas – Arctic, complex reservoirs, high sulphur etc – has grown. Even in Qatar where gas from the North field has long been considered free, based on the revenue credits from produced associated liquids, recent breakeven development costs have ballooned. Recent Barzan development costs suggest future breakeven costs for North field fed LNG, should it be proposed, at around US$7/mmbtu, up from US$0/mmbtu for Qatargas-2 LNG supplied by gas from the North field. Political issues have further challenged NOC gas for LNG development. Sanctions have stopped LNG projects in Iran and, post the Arab spring, the political sensitivity of prioritising gas supply for the domestic gas market in many Middle East and North African countries, dominated by NOCs, has intensified.

However, recent global exploration success by IOCs has increased the volume of IOC controlled conventional gas by around 440 tcf over the last five years. On top of this, the huge growth in unconventional gas growth focused on North America has also been led by IOCs. As a result the opportunity for IOCs to lead gas supply and LNG development has grown, providing IOCs with greater self-determination, at the expense of NOCs. With exploitation of global unconventional gas at an early stage and expenditure on conventional exploration set to grow, the likelihood is that the volume of IOC controlled gas will continue to grow.

But, while the importance of NOC control over gas resource may diminish, the challenges to develop LNG supply continue to mount, not least due to the needs of domestic markets and local politics. As in the US, gas and LNG exports in Israel have been a politically divisive issue. Israel estimates that it now has enough gas to satisfy domestic demand for 50 years with significant remaining exploration potential, but exports have yet to be approved. Gas shortages in the local eastern Australia market have forced domestic prices to levels close to netback parity with LNG exports and will likely contribute to reducing future LNG exports. Legacy gas exporting countries such as Egypt are joining Indonesia and Malaysia in importing LNG, as domestic markets take priority over gas exports.

Institutional capacity constraints may also restrict the pace of some LNG supply development from future new potential LNG exporters, such as Mozambique and Tanzania. These countries have to overcome the legislative, bureaucratic, customs and financial hurdles associated with large scale LNG developments. The limited administrative resources within government in these countries, and the lack of experience of such complex projects, presents a risk to ambitious project schedules. While many host governments have successfully developed LNG supply in conjunction with international LNG developers, the existence of multiple potential LNG suppliers in both Mozambique and Tanzania presents an additional potential complexity, which runs the risk of potential project delays.

The greater volume of LNG supply potential has resulted in more supply competition but, at the same time, LNG development costs have risen. Typically these cost increases have been dominated by local issues rather than global factors. But as margins are squeezed it seems inevitable that some suppliers will ask their host governments to reconsider the appropriateness of some tax terms to encourage LNG export monetisation.

THE COMMON CHALLENGES

Whether resources/reserves are unconventional or conventional, existing or yet to be discovered, the challenges associated with accessing and developing them are still fundamentally technological, commercial and/or political in nature, with the relative importance of the challenges depending upon the type of resource as well geography.
• **Technical**: can you actually develop the gas;

• **Commercial**: can you turn the gas into LNG in an economic fashion, particularly given the alternative options for monetising it such as local markets or pipelines; and

• **Political**: can you get permission to access and then export the gas, particularly in light of growing local demand for gas in many gas producing countries.

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<th>Technical</th>
<th>Commercial</th>
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<tr>
<td>Unconventional</td>
<td>More challenging, need for supporting infrastructure, experience curves</td>
<td>Calorific value typically low</td>
<td>Fracking and associated environmental issues</td>
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<td>Exploration</td>
<td>Is the gas there and recoverable</td>
<td>Cost of development, domestic market obligation etc.</td>
<td>Export sensitivity</td>
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<td>Exploitation of Discovered Resource</td>
<td>Limited as already discovered</td>
<td>Terms of access</td>
<td>Exports can be politically sensitive</td>
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**THE CORPORATE DIMENSION**

Having established and analysed the generic options that companies have for accessing the gas required to support the development of additional LNG supply capacity, we now consider how a cross-section of selected LNG players are actually pursuing these different options in the development of their LNG businesses.

However, before doing so, we first take a step back to early 2007 when we prepared our LNG15 paper, to see how the selected companies were accessing the gas required to support additional LNG supply capacity at that point in time.

**THE PICTURE IN EARLY 2007**

As part of our LNG15 paper we examined where seven major players in the LNG business were attempting to commercialise known gas reserves to support the development of new LNG supply projects/trains and/or where they were exploring for gas to support such developments. Our findings are summarised in Figure 9.
At the time, we observed that most players were pursuing strategies that combined exploiting known resources with exploration for new resources. The exploitation of known resources to support LNG developments was largely confined to two countries – Nigeria and Australia, and while players remained interested in Qatar there was precious little in the way of new opportunities to pursue given the country’s moratorium on new gas projects. The shutdown of opportunities in Qatar was also leading to the pursuit of some exotic LNG projects, including for example PetroCanada attempting to develop the ‘Baltic LNG’ project with Gazprom, which would have seen some of the latter’s pipeline gas liquefied near to St Petersburg for export into the Atlantic Basin LNG market.

Almost all players were also actively exploring for gas to support new LNG trains, and this exploration fell broadly into three categories:

- **Moratoria busters**: Exploration intended to prove up additional reserves that would see moratoria on additional exports lifted. Key countries in this category were Algeria, Egypt and Libya;
- **Expansion plays**: Exploration looking for gas that could be used to expand existing LNG supply facilities. Australia and Nigeria were the key focus countries in this category; and
- **Frontier plays**: Exploration to open up new areas for LNG development, including Mauritania and Papua New Guinea (PNG). However, this frontier activity was limited, reflecting the fact that frontier exploration was really the preserve of the small E&P players, who on finding large commercial gas reserves would then typically sell those reserves (or themselves) to the larger players.

At the time, none of the players was exploring for gas in either East Africa or the Levant Basin, both of which have subsequently seen major gas discoveries as noted earlier in this paper. However, perhaps most interesting of all is the fact that at that time none of the players was seriously looking at using unconventional gas as a feedstock for LNG supply.
THE PICTURE IN EARLY 2013

We now consider the positioning of the same companies as of January 2013, and add in three others (Anadarko, Eni and Statoil) all of which are actively pursuing LNG developments, in order to determine if there have been any noticeable shifts in the companies’ LNG focused gas resource positioning since 2007 (Figure 10). Again, the emphasis is on how the companies are accessing the gas required to support the development of additional LNG supply capacity.

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<td>Algeria, Australia, Brunei, Libya, Nigeria, Norway, PNG, Yemen</td>
<td>Argentina, USA</td>
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Notes:
Countries in bold are, in Wood Mackenzie’s opinion, the primary focus of attention for that company in terms of providing feedstock for new LNG developments.

Unconventional resources in the US are typically not directly connected to the proposed LNG export projects, rather the feedstock gas for the projects will be sourced from the US pipeline network. See discussion under Key Shifts in Positioning.

Figure 10: Gas Resource for LNG Focus of Selected LNG Players (as of early 2013)

KEY SHIFTS IN POSITIONING

While exploration remains a key aspect of every company’s LNG development strategy, two significant shifts in positioning from 2007 to 2013 are immediately apparent: i) the exploitation of discovered conventional gas resources is no longer just about Australia and Nigeria and ii) almost all of the companies now have some kind of unconventional upstream gas position linked to at least one of their LNG developments.

Exploiting discovered conventional reserves in Australia remains important to many IOCs, whether to underpin new mega-projects like Browse or to support the future expansion of projects currently under
construction such as Gorgon and Wheatstone. However, monetising IOC controlled discovered gas resources in other countries has now become a key industry theme. Given the significant discoveries made offshore East Africa, monetising that gas is now a priority for several companies, typically hand in glove with exploration for additional gas to help optimise development scenarios. The rise of shale gas in North America has also helped to focus attention on the development of Alaskan North Slope gas as LNG feedstock. This is because the availability of huge quantities of relatively cheap shale gas production has created a relatively low long-term outlook for Henry Hub (HH) prices, which makes it highly unlikely that piping Alaskan gas to the Lower 48 will make economic sense any time soon. Indonesia has also seen something of a renaissance in terms of players looking to monetise existing gas resources either through the development of new trains (Tangguh 3), new projects (Abadi FLNG) and/or backfill of the existing Bontang LNG facility.

Several players continue to battle the numerous political and commercial challenges associated with monetising discovered Nigerian gas via expansions of Nigeria LNG (NLNG) or the development of greenfield projects such as Brass LNG, but otherwise, exploiting NOC gas seems to have lost favour amongst the companies. The IOCs seem to continue to blow hot and cold when it comes to monetising discovered gas reserves in Russia, and arguably the IOC Novatek’s Yamal gas currently looks as likely to be monetised as LNG, as does any of NOC Gazprom’s reserves. While the selected players collectively have access to a lot of NOC controlled gas, from Brazil to Russia to Venezuela, they generally don’t seem to be actively pursuing LNG developments in those countries, preferring to focus their efforts elsewhere in light of the previously highlighted issues associated with developing NOC controlled resources.

Player focus in terms of exploration has shifted a little in geographic terms, East Africa has become a key focus alongside Australia, with North Africa being de-emphasised in light of political issues and the previously discussed strong local demand for gas. Exploration remains a key tool for all companies, although in some cases it is probably more about proving up additional resources to maintain production from existing facilities (e.g. Brunei, Malaysia and Oman) rather than looking to actively underpin new ones. One area that does not appear in Figure 10 but which is worthy of mention is the Levant, where there is a lot of interest in accessing exploration blocks, as well as corporate activity as evidenced by Woodside’s recent acquisition of a 30% interest in the Leviathan field offshore Israel. Indeed, we also expect to see further M&A in East Africa as players seek to consolidate, sell down and/or gain new positions.

Figure 10 also highlights that most players are now actively seeking to monetise unconventional gas resources through additional LNG plants/trains. As already discussed, Queensland has been a key area of activity, but the appetite for developing more CSG or CBM to LNG projects there has cooled considerably since LNG16. Instead, attention has shifted to monetising unconventional gas reserves in North America via LNG, particularly in western Canada. While many of the companies in Figure 10 have significant US unconventional gas production, they are typically not trying to link that production directly to the proposed LNG export plants in the US, largely because they don’t need to. They can sell their production into the US gas market at a HH linked price and buy gas near to their chosen LNG plant at a HH linked price. There is no need for physical integration of upstream resources with a liquefaction plant as is the case in much of the rest of the world. Rather, we expect that some players will look to ‘virtually’ link their positions to create a synthetic hedge in that higher HH prices could erode margins from selling US LNG into oil-linked Asian markets but the HH-indexed US upstream position would help to offset that. However, in Canada most of the gas reserves that these players have are technically stranded, so creating a direct link between the reserves and an LNG export plant makes a lot of economic sense, as otherwise they would be unlikely to be monetised for a significant amount of time.

So in summary, we are seeing many players pursue a portfolio approach; combining exploitation of existing discovered (and IOC controlled) conventional resources, with exploration to augment some of those resources as well as to open up new areas, and the exploitation of some unconventional gas, typically in Australia and/or North America.
OTHER CONSIDERATIONS — REMEMBER THE BUYERS

In the paper thus far, we have considered the business of accessing gas resources to support the development of additional LNG capacity almost exclusively from the perspective of the developers / sellers of the LNG. However, it is important to recognise that the buyers of the LNG from that capacity are also likely to have some influence on the way in which the developers secure the gas feedstock. In our opinion this is particularly pertinent at the current time given that there are so many proposed new LNG projects / expansion trains looking to secure market with deliveries starting in the 2018/22 period, which means that, to some extent, buyers can pick and choose their preferred projects. As such, we believe that developers need to consider potential buyer preferences when developing their resource capture and exploitation plans.

In our view, the key factors for developers to take into account include:

- **Desire to reduce exposure to the Middle East / improve supply diversity:** During the last decade many Asian LNG buyers have expressed some concern about their level of exposure to the Middle East region in the context of their overall LNG supply portfolio (in some ways mirroring earlier concerns about exposure to crude oil supplies from the region). These concerns have been reinforced in the last couple of years by the geopolitical tensions around Iran which could potentially create major supply issues for buyers if the Straits of Hormuz were closed. Arguably these concerns around the Middle East are one of the key reasons why Asian LNG buyers have become such large purchasers of Australian LNG, as it was seen as a safe country offering great diversification potential given that LNG could be purchased from the west, north and east of the country. However, it is our understanding that many of the same buyers have now started to consider whether they are too exposed to Australia, which in our opinion, is likely to lead them to securing a lot of their next volumes from other geographic sources including East Africa, Canada and the USA. Concerns about political issues are also likely to mitigate against purchases of LNG produced from NOC controlled reserves in places such as Venezuela, Iran, Russia, Algeria and Nigeria, helping to reinforce the focus of developers on IOC controlled gas in East Africa and North America.

- **Desire to purchase HH indexed LNG volumes:** Many Asian LNG buyers, and particularly the Japanese, are currently very keen to purchase LNG on a HH indexed basis, even if only through partial indexation to HH in a hybrid HH/oil deal. This is primarily an attempt to procure what they believe will be cheaper LNG, but also to create some indexation diversification so that not all of the LNG is linked to the oil price. In theory, this could lead to significant purchases from either US and/or Canadian LNG projects where the alternative outlet for the feedgas is a HH indexed local market, and as such, the cost of that gas is linked to HH. This could create pressure on LNG project developers to ensure that they have access to projects in Canada and the US. However, as discussed previously, having a US LNG export position does not necessarily necessitate the developer securing an upstream gas position (although in Canada an upstream position will likely be required). It is interesting to note that some of the proposed projects in East Africa are willing to offer HH indexation to buyers, even though their feedstock cost is in no way linked to HH, creating an alternative for developers to taking a position in the US or Canada.

- **Desire to develop unconventional upstream oil/gas positions:** Numerous Asian LNG buyers and upstream players (often at the urging of their Governments) have already started to take unconventional upstream positions in North America or have publicly expressed their desire to do so. As part of these investment strategies there is generally a desire to try and link the gas resources acquired/developed with LNG production that can be delivered to the home country (via physical or virtual integration), although in many cases the amount of LNG purchased is considerably greater than the gas produced. As such, we expect this desire to build upstream positions and capability to reinforce interest in purchasing LNG from North America.

- **Interest in buying rich LNG:** Given the general shift towards leaner LNG, Asian buyers in particular are likely to look favourably upon those supply sources that can offer richer LNG and this could steer developers towards additional resources in SE Asia or Papua New Guinea, for example.
In summary, assuming that LNG project developers take buyer preferences into account, we would expect this to reinforce the focus on exploitation of discovered conventional gas resources in East Africa (with selected further exploration) and on unconventional resources in North America. Buyer preferences should also reinforce the lack of momentum that we see around the development of NOC controlled resources, but interestingly may sit somewhat at odds with the developers focus on looking to exploit additional discovered resources in Australia and to explore for more gas there.

CONCLUSIONS

 Significant additional liquefaction capacity will have to be developed in the next decade or so in order to meet the forecast growth in LNG demand and to compensate for the forecast decline in production from existing, operational LNG capacity. This new capacity will in turn require large volumes of feedgas and developers therefore face the challenge of accessing those gas resources.

The good news for the LNG industry is that since the LNG15 Conference the gas resource base has increased massively. Unconventional gas has been key to this increase, particularly in North America, and we expect to see additional increases in the future as other countries follow the lead of the US and develop their unconventional gas resources. The last six years have also seen a lot of gas focused exploration which has increased the discovered gas resource bank and opened up major new potential LNG plays, most notably in East Africa. This combination of focus on unconventional gas and exploration success has increased the size of the gas resource base so much that NOC controlled resources are now arguably less important than they were.

From the LNG industry’s perspective this now means that the big challenge is how to combine exploitation of discovered conventional resources, with exploration for more gas and the development of unconventional resources. While unconventional gas to LNG remains a key industry theme we see limits to its ultimate role, driven by a combination of competing domestic calls on the gas, economics and environmental concerns. Gas focussed exploration is expected to continue as a major theme, particularly in light of burgeoning exploration budgets, but there is likely to be a need for greater or increased focus, otherwise players risk just adding to the bank of already stranded gas. This focus may include targeting additional volumes of wet gas. The loser would appear to be NOC controlled resource, with much of the industry now appearing to shun it in favour of IOC controlled gas. However, regardless of how the different types of gas are targeted, the business of developing new LNG capacity is expected to remain difficult for a mixture of technical, commercial and political reasons.

These trends are reinforced by our analysis of how a range of players have shifted the way in which they access gas for LNG projects since LNG15. There is greater emphasis on the development of discovered conventional gas resources controlled by IOCs, with East Africa having now joined Australia as a key focus area. This change in focus is partly the result of exploration success, but also reflective of a loss of interest in developing ‘difficult’ NOC controlled gas given the increased set of ‘easier’ options now available. Most LNG developers are also now pursuing at least one development fed with unconventional gas feedstock.

However, while IOC developers have a greater range of projects to pursue, market dynamics mean that they have to take LNG buyer drivers into account. Given buyers’ current desire for supply diversity, exposure to HH indexed gas and interest in unconventional resources, we expect this to lead to continued focus on project development in North America and East Africa.

So, in conclusion, it appears that access to gas is now much less of a worry for the industry than it was at either LNG15 or LNG16, which is good news. However, even with much more gas available and an increasingly diverse set of options open to developers, we expect that the business of developing LNG supply projects will remain a challenge.
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