Gas Strategies

Essential Interviews 2016

Perspectives from gas industry leaders

Gas Strategies 30 Years 1986 - 2016

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Editor's letter

Gas Strategies Essential Interviews 2016 brings together the highlights of a wide range of candid viewpoints from key influencers, at a time of collapsing commodity prices, the rise of new trade flows, delays in the start-up of new projects, and a return to growth for LNG supply.

Insights captured in these ten interviews include the outlook for further project FIDs, critical success factors for an effective value chain, the impact of low oil prices on buyers' choice of supply projects, and the future role of gas in the world's energy mix.

We hope you enjoy reading these interviews and we would be delighted to hear from readers interested in participating in a Gas Strategies interview.

James Allpress

Managing Editor
Gas Strategies - Information Services

+44 020 7332 9900
editor@gasstrategies.com

About Gas Strategies

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Gas Strategies Information Services deliver daily, weekly, and monthly news, features, project updates, interviews, analysis, and articles on key developments and trends in the global gas, LNG and energy industries. Content is accessible online and through our dedicated Apple app, across our comprehensive range of titles:

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Consulting

Gas Strategies' consulting team is passionate in supporting our clients through their most important challenges and in realising their ambitions.

We are a management consultancy focused on the global gas and LNG industry. We provide professional services particularly focused on business and organisational change, project development and all commercial and transactional endeavours.

We are proud to have worked for three decades alongside industry leaders as the global gas industry has rapidly expanded, developed and evolved. We are committed to supporting our clients in achieving their full potential through innovative, insightful and dedicated support.

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Gas Strategies is a specialist training provider for the global energy industry. We deliver gas and LNG training as public courses and in-house programmes. For 30 years, we have helped energy industry professionals at every level - from new entrants to senior management - acquire new skills, knowledge and insights.

As a leading consultancy in the gas and LNG industry, Gas Strategies is well positioned to provide up-to-date practical insight across all our training courses. Each Alphatania course is run by industry experts with many years' commercial experience who are actively involved in key projects throughout the world.

Contents

Jean Abiteboul
President of Cheniere Supply & Marketing

Cheniere began 2015 on a positive note after US regulators approved its 13.5 mtpa Corpus Christi LNG plant, leap-frogging the project ahead of its competitors. Corpus Christi, together with Sabine Pass – Cheniere's flagship project and the first to liquefy abundant, cheap US shale gas for export – are testament to a new form of business in the LNG industry. According to Cheniere Supply and Marketing president Jean Abiteboul, these projects have introduced a higher degree of offtaking flexibility, which will help companies to better hedge against demand or price risks. These new flexible options, plus the allure of cheap US gas, have attracted less experienced players to the LNG game. Entering the industry has its challenges – not least operational, as the US has learnt. But at a time when even traditional European utilities are willing to gamble on LNG trade, those who embrace change could emerge as the new winners.

What flexibility options do you offer to offtakers?

Under take-or-pay contracts, if something unexpected appears meaning that a company cannot take the gas – such as a drop in market demand, which we have seen in Europe in the past three years – the options are limited. Under take-or-pay contracts there are make-up mechanisms [which ease the take-or-pay burden], but they are not as flexible as what we offer.

Our mechanism in the US is completely different. Companies pay the liquefaction fee – USD 3.5/MMBtu for Corpus Christi, our new project – and can then do whatever they want. If they want to offtake the gas, they can, but if they don't want to they have alternatives, and the only thing they have to pay for these alternatives is the USD 3.5/MMBtu fee.

In such a situation where the buyer does not want to offtake the gas, Cheniere can simply refrain from purchasing gas on the US market. Then there is no additional risk and Cheniere does need to charge anything for the risk burden – provided that there is sufficient notice to organise the logistics.

Buyers may also decide to offtake the gas but redirect it to another market where there is demand, when the market it was intended for is down. They do not have a fixed destination clause in their contracts and can redirect the LNG wherever they want, so they have full flexibility to offtake or not to offtake, keep the gas for their traditional market, or redirect it to a better-priced market.

Having full flexibility on volumes is a way for companies to manage the physical risk of their gas balance.

But when it comes to financial risk, they could still lose USD 3.5/MMBtu?

Yes, but presumably they won't be in a situation where they will be unable to offtake the gas for the duration of the contract – 20 years, for instance. And either way, USD 3.5/MMBtu is cheaper than USD 10/MMBtu under take-or-pay contracts, even if they have a make-up right under those contracts.

Offtakers assess this risk before signing the long-term contract with us, and such a situation would only occur if they don't need the gas; if the gas is too expensive on the US market; or if they cannot redirect the gas to other markets. So many such events would need to occur simultaneously to result in a situation where they would have to pay the fee and not offtake the gas.

If the oil price falls further and for some reason Henry Hub goes up, then our price formula could be non-competitive. But I don't think this scenario is possible in the long run, although it might be possible in the short-term. It's a very challenging game, and you always have to follow the different moving pieces.

Do you think the Brent/Henry Hub scenario is possible in the long run?

No, because we have plenty of gas in the US. If Henry Hub rises, people will be increasingly incentivised to drill and produce more – this in turn will make the Henry Hub price go down again. The US market is very reactive and responsive to price signals.

The market is extremely elastic. Even if Henry Hub goes up, I don't believe that it can stay at a very high level for a long time because of both the huge shale gas reserves and associated gas from oil.

Producers in the US say that, at a Brent price above USD 60/barrel, there are still plenty of profitable shale oil plays. They will continue to produce oil above USD 60/barrel and there will be plenty of gas associated with oil. There is as much as 15 Bcf/d of potential stranded gas associated with oil production.

Do you think the price of Brent could stay below USD 60/barrel for an extended period of time?

I don't think it's very likely. If oil were to remain at such a low price there would be an increase in consumption, which means that companies would need to develop new [upstream] oil projects around the world.

But the key issue is that new oil projects are not profitable at USD 60/barrel. They will need an oil price above USD 60. The scenario under which the oil price remains low for a long period of time,

and Henry Hub remains high, does not make sense – such situations could occur for a few months at time, but not for long periods.

The country that is suffering the most as a result of the low Brent price is Russia. Lower oil prices, together with the sanctions imposed against Russia, have resulted in a weaker economy.

Do you think that European gas hubs will start tracking Henry Hub more?

The answer is 'yes', and it has already started, even if the physical export of gas has yet to begin. I will give you one example – if you look at the Baltic countries, for instance Lithuania, you will see that it managed to get a price reduction from Gazprom based on their new LNG option, the Independence FSRU. They used LNG prices as a bargaining tool in their negotiations.

Also, last year, the very low Henry Hub price displaced coal from the power generation markets in the US. Most of this coal was then sent to Europe – it could be said that it was an effect of the US gas price.

A lot of companies in the US that used to be in the pipeline or regasification business have switched to developing liquefaction plants with a view to exporting. What is your stance on the challenges they face?

It is important to choose a good engineering company and the right people, but it is clear that with projects multiplying in the US we could start to see bottlenecks at a certain point in time. One of the possible bottlenecks could be in finding specialised workers, such as welders. The human resource challenge will, at the end of the day, be a serious one, and it is already an issue in places such as Australia and Canada.

Until now the US has been an island – only connected to Canada and Mexico by pipeline… and has taken only a small volume of LNG imports. So the US had to hire people from abroad to face the challenges posed by LNG marketing, engineering and operations.

Trading and risk management represent important challenges too – and so does the need to understand different markets around the world, and different cultures.

The US could have a major role in the global gas industry – this has already started happening, even if exports have not yet physically begun. And many companies in the LNG export business are positioning themselves in relation to exports from the US.

People realise that US LNG will be a game changer in terms of quantity and price. It changes the way people do business – it introduces more flexibility, more short-term trading and more arbitrage opportunities. All of this will eventually translate into higher revenues for the gas industry.

How do European utilities fit into the changing marketplace?

Since the beginning of the 2000s the utility business in Europe has changed dramatically. Pre 2000, utilities were monopolies – to put it simply. With the opening of the markets and with new European regulations, the level of risk has increased dramatically for them; they still have long-term commitments with their suppliers, but they do not control their markets anymore.

To cope with this new risk they had to diversify their sales geographically and focus on more types of energy, and on services too – more or less successfully. They have already been testing the opportunities in these new markets.

US LNG is an interesting option for them because, as opposed to their other LNG contracts, they wouldn't need to reload cargoes in case of insufficient demand in their home markets. At the moment they have to deal with fixed destination clauses, but with US LNG they would not have such a clause. The flexibility that we are offering is an attractive option for them, and it will change the way they do things.

Will utilities try to send volumes to their home markets, or are they more likely to redirect to more premium markets with better demand?

They will have to optimise their portfolios and push down their supply costs in order to remain competitive in their domestic markets – which they do not control any more. They now have to be increasingly efficient and create value by taking such opportunities – which indeed is a new business model.

However, things do not change overnight – it's a ten-year process. Long-term contracts in Europe won't disappear overnight; they will change progressively [from being oil-linked to being hub-linked]. They have been changing already – today, more than 50% of the gas sold in Europe is no longer indexed to oil; it is indexed to the TTF and the NBP.

What we will see is a coexistence of the old world and the new world. Eventually, a new balance will be found. Cheniere's past experience, accrued over so many years, will not be wasted or forgotten – it will be useful in this changing process.

But indeed, as always, when a market is undergoing significant changes, there are winners and losers. The utilities that have bought US LNG volumes are part of the bunch trying very hard to be on the winning team.

This interview was first published in Gas Matters, January 2015.

Yesim Bezen, Finance Partner
Onur Oksan, Associate
Bezen and Partners

Occupying a key strategic position between Europe and the gas resource-rich Caspian and Middle Eastern states, Turkey has long aspired to become a regional energy hub. A revision to Turkey's 2001 Natural Gas Market Law (NGML) put before the parliament in early 2014, raised hopes that Turkey could seriously revisit its stultified liberalisation process – largely intended to reduce the market share of incumbent BOTAS and facilitate increased LNG imports. But obstacles, delays and uncertainty continue to fuel doubts over prospects for international investment. Gas Strategies spoke to projects and finance partner Yesim Bezen and associate Onur Oksan of Istanbul-based law firm Bezen & Partners (B&P), and discussed some of the key themes in Turkey's evolving gas industry.

Is Turkey a welcoming environment for international investment? What challenges do foreign companies face?

Generally speaking, Turkey is a good place for international companies willing to invest in energy projects. Turkey has been following a foreign-investor-friendly policy and offers them promising growth opportunities in a relatively stable economic and political environment.

But one of the main challenges foreign companies could face when investing in gas projects is insufficient liberalisation of the market. The state-owned enterprise BOTAS continues to maintain its grip on the import of natural gas and a natural gas spot market has not yet been established. The draft law, currently dormant, is expected to remove some of the hurdles standing in the way of the liberalisation.

What is the latest news on the proposed revisions to the NGML? Has the government offered any more certainty on its progress?

Since its submission to parliament on 4 August 2014, not much progress has been achieved on the draft law amendment to the NGML. After a two-month recess, parliament reconvened on 1 October but the draft law did not find its way onto the agenda.

The deliberations on the draft law appear to continue at the commission level. There is no visibility offered by the government as to when the draft law will be moved to the plenary. Due to the upcoming general elections in June, the parliament will go into a recess at the end of March, making the draft law's entry into force before the elections less probable.

What investment opportunities could emerge from the security of supply measures envisaged in the draft law?

The draft law places significant emphasis on LNG. Currently, LNG makes up a very small percentage of natural gas imports in Turkey. The draft law offers important prospects for LNG terminal investments; it introduces the operation of LNG terminals as a separate activity, which was previously included within the scope of natural gas storage and makes it subject to obtaining of a licence from the regulator.

More importantly, it grants those persons who hold such licence the discretion to determine tariffs applicable to services they will be providing. The draft law also offers an 85% discount on fees payable to the state for using state-owned land to construct LNG terminals.

How likely is the unbundling and restructuring of BOTAS, and what will be its possible effects on gas market liberalisation and Turkish natural gas imports?

BOTAS' unbundling and restructuring is very dependent on the fate of the draft law. Once it enters into force, BOTAS will go through a demerger process and be unbundled into three separate entities. The draft law, in its current form, restricts BOTAS from entering into new purchase agreements but at the same time envisages an exception for supply security reasons.

BOTAS' unbundling may contribute to the liberalisation of the market in two ways: increased competition in the market, and the introduction of cost-based pricing via removal of subsidies currently exercised by BOTAS. Whether this could be achieved or not will, however, depend on the Turkish state's commitment to decreasing BOTAS' influence.

The privatisation of Istanbul's natural gas distribution company is one possibility implied by the liberalisation process. Is this happening, and what are the implications?

The draft law contains several provisions in respect of the privatisation of IGDAS, the natural gas distribution company of Istanbul. It sets out that the Privatisation Administration is entitled to carry out this privatisation, which will be made through sale of the Istanbul Municipality's shares in the company. It also forms the legal basis to restructure its debts to BOTAS to make its sale even more appealing.

With the draft law being put on hold, the privatisation of IGDAS is unlikely to take place in the near future. A provision has been included in a draft bill to cater for the privatisation of IGDAS, but it was reported recently that the provision has been deleted during the deliberations at the commission level. This move is interpreted as the Turkish government holding off the privatisation for the moment.

How is the Trans Anatolian Pipeline (TANAP) progressing, and what are Turkey's prospects for becoming a regional hub?

The Turkish section of the TANAP project is fully on track. The project company awarded first tenders for the construction of pipelines, to which several international and domestic companies showed interest.

Important developments are also taking place on the legal front. Several amendments have been made to the host government agreement concluded for the TANAP project in October last year. The amendment text extended several incentives to facilitate TANAP's implementation.

It is worth mentioning the exemption from VAT granted for the delivery of all goods and services for the construction and maintenance of the pipeline. The Council of Ministers has also taken a series of resolutions to implement expedited expropriations of land on which the pipes will be laid.

This interview was first published in Gas Matters, February 2015.

Vladimir Drebentsov
Head of Russia and CIS economics, BP

Russia's gas industry is at a turning point, both politically and structurally. Gazprom is facing increasingly tough competition – internally in the shape of Russia's independent gas players, and externally in the form of flexible, cheap, new LNG supply and future gas flows from the Caspian through Turkey to Europe. And with the recent dramatic fall in crude oil prices, Gazprom – and Russia as a whole – has been fundamentally challenged to remain competitive in spite of its largely oil-linked EU supply contracts. How can Gazprom meet these challenges? Gas Strategies discussed Russia's future supply strategy with BP head of Russia and CIS economics Vladimir Drebentsov.

Will Gazprom be able to maintain its monopoly on pipeline exports?

It will for some time. However, speaking at a meeting of the EU-Russia Gas Advisory Council in January 2015, a senior representative of the Russian Parliament (Duma) indicated that Gazprom's monopoly could be broken after 2025, with Gazprom to be split into two companies – with the transportation part becoming separate from the production part.

This will not necessarily mean that the export monopoly disappears. It's just that Gazprom, in its current shape, will lose it. If the government prefers to keep the monopoly on pipeline exports, this right will be vested in a new transportation company, which will likely remain 100%-owned by the government in any case.

How can Gazprom contend with the Russian independents in its future sales strategy?

Gazprom is increasingly losing domestic gas market share to the independents, who offer gas to Russian customers at lower prices. Gazprom prices are the only ones regulated by the government, and have been set rather high – the legacy of Gazprom's past success of persuading the government, back in 2006, to approve a price schedule that assumed circa 15% increases per annum – even though price hikes have been frozen in recent years.

Last year, Gazprom accounted for around 55% of Russia's domestic gas consumption, down from 80% ten years ago. If the trend continues – independents plan to almost double their gas output, and we don't see how Gazprom can stop them – Gazprom will become even more export-volume conscious.

If Gazprom is successful on the export markets, it may preserve its share of Russia's gas output (68% in 2014). But competing with independents on the domestic market will remain challenging.

Since early 2014, Gazprom has been asking the government to allow it to sell gas to domestic customers at a discount. But permission has not yet been granted due to opposition by the independent producers, who claim that this should be done only if they are granted access to part of Gazprom's export revenues. Otherwise, Gazprom would be in a position to cross-subsidise domestic sales from its exports – something independent gas producers can't do.

Will Gazprom want to maximise sales to Europe on an ongoing basis?

Yes, exports are the main hope for Gazprom – it wants to keep growing. In fact, even though remaining vocally adherent to oil-indexation in its European long-term contracts, in recent years, Gazprom has demonstrated higher price flexibility in Europe than many observers typically notice.

Moreover, Gazprom significantly increased flows to its European trading arms (Gazprom Marketing and Trading), which don't have long-term oil-indexed contracts, but rather sell gas at European hubs. At a minimum, close to 10-12 Bcm/year of Russian flows to Europe were sold directly at European hubs in 2013-2014.

How might the European gas environment change in light of Gazprom's wider strategic objectives?

Due to declining indigenous production (-36% in 2035 versus 2013) and growing consumption (+19%) Europe's dependence on gas imports is growing. Russia is expected to continue playing the leading role in satisfying Europe's call for gas imports.

However, as Europe will be diversifying sources of supply – primarily by expanding LNG imports and attracting pipeline supplies from new sources (the Caspian, etc.) – Russia's share of European gas consumption will likely remain flat, not exceeding the current 33% by 2035.

Can the domestic price of Russian gas reach netback parity – the equivalent of EU prices?

Not in the immediate future. For many years, Gazprom was striving towards this goal. It was even mentioned as a target in the Government Price Decree of 2006. However, it never made much economic sense for Russia as a country. As long as Gazprom enjoyed a monopoly on the Russian domestic market, it would have meant that Russian customers would end up paying well in excess of long-run marginal costs.

Moreover, the recent rouble devaluation has made Russian gas prices much lower in dollar terms, and with excess capacity available from both the independents and Gazprom, it's difficult to see domestic gas prices growing fast. Russian domestic gas consumption has been stagnating and is not expected to grow much in the future. Gas penetration is already rather high in Russia, with gas accounting for 53% of the primary energy consumption.

Can Russia really bypass Ukrainian transit?

If the third and fourth strings of the Turkish Stream and Yamal II get built, Russia will technically become able to bypass Ukraine for westbound gas shipments outside the FSU.

The Nordstream (55 Bcm/year), Yamal-Europe I & II (48 Bcm/year) and Turkish Stream (63 Bcm/year) combined may suffice to cover shipment needs for the years to come. Russia exported to Europe – excluding the Baltics and Finland, which are served by distinct pipelines – 158 Bcm in 2013 and 143.5 Bcm in 2014.

This interview was first published in Gas Matters, March 2015.

Stefan Judisch
Former CEO of RWE Supply & Trading

Stefan Judisch began his career in 1984 at the former German conglomerate Metallgesellschaft and later moved to UBS to build its non-precious metals commodity business. In 1999 he joined RWE as the founding managing director of RWE Energy Trading, before leading gas wholesale activities in the newly formed RWE Gas Midstream. In 2008, RWE Trading and RWE Gas Midstream merged to form RWE Supply & Trading, with Judisch taking the helm as CEO from 2009 until his retirement in early 2015. With years of experience in commodities including LNG and gas trading, portfolio management, business development and wholesale origination, Judisch spoke to Gas Strategies about the past and present of the gas sector, the sometimes painful process of change, and the challenges facing the industry.

Disclaimer: Any views or opinions presented in this interview are solely those of Stefan Judisch and do not represent those of RWE Supply & Trading or any affiliated company.

You have seen a huge amount of change since you first entered the energy sector. What lessons have you drawn from that experience?

At the end of the day, each generation needs to make its own mistakes. If older people tell youngsters what to do and what not to do it normally doesn't help. The biggest learning of all – I think my most fundamental – is that nobody is bigger than the market.

Not even politicians are bigger than the market. They are not on top of market dynamics and that's why, when they try to intervene, it normally goes wrong or gets very expensive.

As the market continues to evolve, what do you consider the key requirements for success?

The globalisation of the gas business has been the most important aspect of my career.

I remember my first energy deal at UBS – we hedged long-term a German gas procurement contract for a municipal power station that was indexed to so-called "Rheinschiene" heating oil. You needed to understand the global oil market dynamics as well as the German specifics of the Rheinschiene price formation, which again was a number determined and published by the German Federal Bureau for Statistics.

These days, trading firms increasingly need to understand global relationships between various energy and non-energy commodities. Because, as the gas market globalises its influencers also globalise.

For example, the question of whether LNG will come to the UK or not will massively influence not only the gas price in the UK, but also on the continent, because the UK and continental gas prices are now very closely correlated.

If you don't understand heating and cooling demand in Japan, or water levels and hydropower production in Brazil – to take two examples from the Atlantic and the Pacific – you can't really understand where gas prices in Europe are going, nor where power prices are going for all markets where gas-fired generation sets the marginal price.

These global influences become more diverse over time. Before the end of this decade, as North American LNG exports come into play, gas-to-coal switching in the US domestic market will become relevant for the European power generation merit order, and therefore gas-to-coal switching here.

Another example of coal-to-gas competition is China's multiple fertiliser production facilities based on coal, and there are many more of these examples – far beyond energy and global weather.

What are the prospects for growth in gas-fired generation?

I think gas missed the opportunity to become a major player in power generation to replace coal because it was always too expensive, and now renewables have caught up in the cost curve, and that's where the core problem for gas in power generation lies.

We see a massive, continued cost deterioration for power production from renewables. For example, the Dubai Electricity and Water Authority (DEWA) recently signed a deal for 20-year solar PPA at USD 5.9 cents/kWh. This is already – at the equivalent of EUR 50/MWh – competitive with the price at which gas-fired plants are dispatched (on marginal costs) in Europe at the moment.

The point is simple: Dubai has more sun, so we won't get to that level in Europe, but what will happen is that the whole perceived growth area for gas in power generation – in the hotter and sunnier regions in North Africa, the Middle East etc. – will directly or indirectly release gas to the international markets.

One of the main reasons why gas will remain well supplied is lower-than- anticipated global demand growth. But at the same time, solar in Europe will grow, wind will grow, and with Tesla recently announcing a very surprising move (from a cost point of view) on the lithium battery, I can't see any bright future for gas volume growth in Europe.

With this cost framework for renewables, will a country like Saudi Arabia, for example, move from oil to gas in power generation, or straight from oil to renewables?

Is there still a chance for a 'Golden Age of Gas', as suggested by the IEA?

If you look at the last 20 years of IEA predictions for gas growth in power generation, they didn't get much right. The reason is in the methodology that most economists use to approach long-term price prediction.

They look at long-term marginal cost under the assumption that every investment needs to earn the capital invested back – but the reality is that many investments don't return their capital costs and entire industry sectors go bust.

We have experienced a number of hypes about industries, from solar panels to dotcoms. In both industries, in the first investment cycle, people just didn't make money – now they're making their money.

You have companies like the solar developer, Conergy, returning from bankruptcy. It's a bit like what they say about owning hotels – only the third owner of a hotel will make money, because the initial green-field capital investment is written off.

When you look at what's happening with E.ON, is this a model for other utilities? Does it set an example for others to follow?

The E.ON re-structuring leads to a discussion about efficient capital markets. When I started in the energy utility business, the era of regulated business had just ended. In the late 1990s in the UK – where the regulatory pricing for grids happened earlier than in most of the European continent – the integrated companies basically split themselves up into regulated and non-regulated businesses.

What we see now is that, in other parts of Europe, this is happening for the same reason. The balance sheet of a commingled utility, with both risky wholesale market revenue streams – like power generation – and regulated businesses that can afford a high leverage, get confused in the capital market. I think what E.ON's trying to do is to remove this confusion over its balance sheet.

In many parts of Europe, such as Spain and Italy, this split between regulated and non-regulated has already happened – despite the fact that retail prices in most of the southern European markets remain under strong regulatory and political influence. What we see happening is markets driving (capital) efficiency – so it's not a surprise at all.

What policy changes could be implemented to support gas-fired power in Europe?

The carbon tax in the UK, and now the discussion in Germany about additional intervention in the carbon market. Ultimately I think it will be expensive, like any political intervention, and might have unwanted side effects – which will most likely lead to further intervention. It is like Ludwig van Mises, the great Austrian economist, said: "The state can be and has often been in the course of history the main source of mischief and disaster."

The EU Emissions Trading System (ETS) should be the only tool to cap carbon emissions. ETS works – and it cannot be blamed for producing a perceived wrong outcome regarding price. The outcome is correct – the carbon emission reduction demanded by politicians is being achieved at the lowest possible costs. The markets can't be blamed if politicians make wrong assumptions when they set the volume targets.

Cost advantages through German subsidy schemes have now led to renewed growth for renewables. It's now economically sensible for the individual (property- owning) household in Germany to put solar panels on his or her roof, because their overall costs without subsidy are about EUR 12 cents/kWh. By contrast, if you take your power from the grid you pay around EUR 30 cents/kWh.

This economic incentive will drive people, once the German renewable feed-in tariff system stops, to use as much of the power they produce themselves as possible. That will also trigger the use of power storage – in the widest sense – at home. This trend will also be accelerated through the (perceived) autonomy of the end consumer.

This is obviously bad news for centralised generation, and I think this is irreversible unless the government were to introduce something like a solar tax.

How would you sum up the status quo for someone just entering the business?

Accept the reality and take it on. There is a systemic change in the entire energy business: we've had a good 120 years moving to a centralised energy system, since the first public power station started operations at 57 Holborn Viaduct, London in January 1882, and now we're moving to a decentralised system – but it will be centrally managed.

The solar panel is having the same impact on centralised power generation as the passenger car had on the railways. Railways for people transport are, in many countries, kept alive by public subsidy because of its role as the central backbone for transport. The advance of motorised road transport basically killed the unsubsidised rail industry.

And there is your analogy for the free-market based, competitive energy utility business. The systemic change is being caused by highly subsidised renewables.

This interview was first published in Gas Matters, March 2015.

Octavio Simoes
President of Sempra LNG

Octavio Simoes, senior vice president of Sempra International and president of Sempra LNG, talks to Gas Strategies about business models and strategies, Sempra's LNG ambitions, and the outlook for further FIDs for LNG projects, given the rapid decline in oil prices.

Of the US projects which have taken FID after Cheniere, Sempra was the last to announce its project, and it caught the others up. How was Sempra able to do this?

We structured things in a way that our experience told us would get it done quickly, and that's the value of good development. Some of the folks that are doing things have never permitted a project with FERC [the Federal Energy Regulatory Commission], or worked with the DOE [Department of Energy] before, so they go a little bit by trial and error and then they have to overcome the obstacles and then go back to the drawing board.

The other aspect of FID is financing. When we structured our commercial contracts with our customers, we always had in mind what the financing requirements would be. By the time we went to financing we were able to leapfrog all the other projects because the lending institutions got exactly what they wanted.

Can you elaborate on what the DOE and FERC are looking for?

They're looking for things that are proven technically…They're looking for things that are customary. So if you come up with something new that's never been done before in certain areas, maybe it's a better solution but it's going to slow the process because the FERC staff will have to evaluate something completely different. So we prepared all of the source reports required by FERC, using techniques and models that FERC is used to seeing.

Where are the most promising areas to develop liquefaction facilities over the next decade?

The US is very well positioned for good development. But it will be limited because the model itself – using a liquid hub behind production – is not something that everyone can jump into. The question will become: what is the next lowest available marginal cost of production?

Are the volumes you are tolling likely to already have firm markets or do you expect some of the tollers to be looking to sell on?

Most of the volumes are sold to a third party. In the particular case of Cameron, I'm pretty sure [the tollers] GDF Suez, Mitsui and Mitsubishi have sold most of it. They may have retained some very small quantities for some potential plays where they would use that supply in order to get other business. But this was a project financed effort, so lenders look to the feasibility and the viability of where the tollers have secured revenue to support their commitments.

What effect will the rapid decline in oil prices have on a potential buyer's choice of LNG projects?

First of all, we have had rapid declines in oil prices in the past. People seem to have forgotten that. We certainly had them in 1999 and 2008, and the LNG remained steady. We are having the same phenomenon now. The question for buyers is, now that we have made US projects feasible with flexibility of volume and destination, how are other producers around the world going to respond to that?

What is the outlook for further FIDs for US LNG projects, where feed gas costs are market price-linked, given the rapid decline in oil prices?

I think it is very good. Frankly, if oil price stays high, then people will clearly still want LNG from the US. And if oil prices stay low, then the US projects are the only ones that are economic to build. However, in the LNG world, people like diversity and people make decisions on where to get supply based on reliability and diversification. So I don't think that all of a sudden all new incremental capacity would be supplied from the US. In the long-term, over the 2025 to 2030 horizon, of the total demand of LNG in the world the US will be in a position to supply about 20% of it.

Do you think low oil prices are here to stay?

I don't know. Our opinions are always shaded by our experience. I've been doing this for some time now and I've never seen a situation where a drop in oil prices stays for too long. It's a highly valuable commodity. It has one of the highest concentrations of energy on a volume basis. It is incredibly flexible and easy to transport. If oil stays low, you'll see places around the world using more oil, and then the price of oil will go up.

Will Basel III liquidity restrictions impact on the availability of funds to the LNG sector? And will projects get delayed as a result?

What you have seen for a number of projects that have reached financing, is that the sources of funds for investment are very diverse and they're not just limited to commercial banks and the restrictions that come from Basel. You saw Freeport getting financing from a lot of private funds. There's a lot hedge funds looking for investment opportunities in the LNG space in the US. You see the Export Credit Agencies, you saw how much money JBIC put in our project. I don't see that as an issue. There's a lot of money and these are good investments.

This interview was first published in LNG Business Review, March 2015.

Sheikh Imran ul Haque
CEO, Elengy Terminal Pakistan Limited

Pakistan's USD 135 million LNG regasification terminal has been completed on time and ahead of schedule. The FSRU berthed on 26 March, loaded with LNG from Qatar. Under an agreement, the government had faced a USD 275,000/day capacity charge for not importing LNG into the terminal by 31 March. Sheikh Imran ul Haque, CEO of the Elengy Terminal Pakistan, talks to Gas Strategies about the key challenges and critical success factors that led to the successful completion of the terminal ahead of schedule, as well as the future of gas imports needed to meet Pakistan's growing demand. Elengy Terminal is a 100%-owned subsidiary of Engro Corporation. Imran is also CEO of Engro Vopak Terminal that provides storage facility for bulk liquid chemicals and LPG in Pakistan, in a joint venture of Royal Vopak and Engro Corporation.

What were the key challenges to establish an effective value chain for the Elengy FSRU project and how were they overcome?

We were given 335 days by the government as part of our contract to establish the terminal. As part of that, the penalties were very severe. For each day that we were late, we had to pay USD 150,000. What went in our favour was the fact that we had worked on this project for some years already, not necessarily in terms of only engineering, but conceptually we knew the business case and understood what we wanted to achieve and had knowledge of the technology. During the time it took for the government to sign and negotiate the contract with us, we were already committing our resources. So a little bit of preplanning, and knowledge of the structure that we wanted, and the ability to move very quickly in putting the resources into the project with the ability to raise funds off the corporation balance sheet, always put us in a strong position.

What about the onshore facilities, what were the key challenges there?

The first challenge was the timeline. The second was acquiring the material necessary for construction from far and wide. Third was ensuring that the shipments arrived on time. The other element was negotiating and signing all the contracts and obtaining necessary regulatory permits. Also, we had to raise bridge financing as project finance was not available within the short time period we were looking to deliver this project. Finally, since this was Pakistan's first LNG project, there was a lot of hand-holding required at various levels amongst the stakeholders including briefings and presentations to the port authorities, the government, and the regulator, just so we could get the paperwork together. All those challenges had to be met in the short period of time that we had. This project is a great example of what public private partnership can achieve.

What is the term of the FSRU deal?

The agreement with gas utility SSGC is for 15 years, so this is for 15 years as well. It's a back-to-back agreement where Excelerate has to deliver and ensure 95% availability. We have the capacity to deliver 600 MMcf/d with peak of 690 MMcf/d.

And what is the regas tariff?

The levellized tariff is 66 cents/MMBtu over 15 years.

Given the number of proposed FSRU projects that fail to reach FID, what do you think were the critical success factors behind the Elengy Terminal?

One of the factors was that we did our own bridge financing, arranged through local banks. In parallel we structured and progressed the project with a view to securing project finance. Secondly, the FSRU was already available, and it was already constructed. It was not an FSRU that was being built for this particular project. The availability for the vessel was there, and it was available in the timeframe that we wanted. And thirdly, we were able to push through things. Our Board supported the projects and believed that the risks were worth taking to place Pakistan on the LNG world map. There has been a lot of coordination. We worked extremely hard in our teams to make sure that things went through. We cut red tape. We focused on the shipments and the timeline and the contractors and everyone else.

What is the main application for the terminal: supply shortage (given Pakistan's estimated 2,000 MMcf/day supply gap), fuel conversion for power generation or supply security?

The first one is the supply to power, especially to plants which operate on oil fuel and diesel. These are plants which are dual-fuel operated, so when there's no gas, they're running on diesel and furnace oil, and they're producing very expensive electricity. The first 325 MMcf/d will be supplied to those plants, and the effect will be that the cost of generation will come down and the average tariff in the country will also decrease. The government has also announced that it will build 3,600 MW of additional gas-fired plants which would be supplied by LNG imports.

The second sector to which the LNG imports will be supplied to is the transport sector, where it will be regasified and used as CNG in vehicles. The other sector is the fertilizer sector.

What does the Elengy terminal mean for Pakistan?

Pakistan has witnessed three or four unsuccessful attempts at building a regas terminal. This successful attempt is going to put the country on the world map. Once the first few cargoes go through, the confidence level is going to go up, and everybody is going to be looking at bringing in volumes. It's too big a market to ignore. 180-200 million people, with 125,000 km of pipeline network. Moreover, if the government decides to deregulate the market and make it easy for people to import and use this commodity, LNG imports will flourish in Pakistan.

This interview was first published in LNG Business Review, April 2015.

Bolaji Osunsanya
CEO of Oando Gas & Power and President of the Nigerian Gas Association

The fate of Nigeria's gas industry is inseparable from the country's geopolitical challenges. Nigeria has the world's ninth-largest gas reserves, but an inadequate fiscal and regulatory framework, insufficient infrastructure, sabotage in the Niger Delta, and endemic corruption are barriers to realising its true potential. But the inauguration of new President Muhammadu Buhari could represent a step change for Nigeria. And where IOCs have failed, Nigeria's indigenous players have built solid foundations with expansive prospects for growth. In July 2014, independent Oando Energy Resources agreed a USD 1.5 billion deal with ConocoPhillips for the purchase of its Nigerian assets, representing proved plus probable reserves of 211.6 million boe. Gas Strategies spoke to Oando Gas & Power CEO Bolaji Osunsanya about the challenges and opportunities facing Nigeria's gas industry.

How would you sum up national sentiment following the inauguration of President Buhari? Do you think there is a better chance that he will succeed in his reforms where Goodluck Jonathan failed?

There is a lot of excitement, but there's also uncertainty about what will be different. President Buhari has the precedent of taking very difficult, progressive decisions and I think the general mood of change in the country should aid that.

For the gas sector, we think it's a unique opportunity to seize the day and use a gas monetisation agenda to propel whatever new thoughts he may have. It will never be about comparing his administration with the previous, but just being positive that the circumstances today will help him to make those gas choices.

It's a low-hanging fruit, the resource is there, the framework to promote its exploitation is already in place – it's just the doing. It's an opportune time for him because if there's any sector that's already well set, then it's gas.

What are the first steps that President Buhari needs to take?

The first priority should be to deal with the commercial structure. Gas is already in the private sector space, and as such, if the government gets the market economics right then the needed gas development would happen as a matter of course.

Commercial structure is the key, and President Buhari needs to take very bold decisions on this. The clamour for low domestic gas prices is mostly self-serving. In trying to keep domestic prices low, the argument has been made that the gas is for power generation and low prices are needed to maintain affordability.

That is not correct: today, most of the same power consumers are generating their own power using more expensive fuels including premium motor spirit, diesel and other fuel oils.

If gas supply is made attractive for the suppliers, with the costs being passed on to the consumer, it wouldn't be inflationary – it would aid availability and would be a more manageable way of ensuring supply. Commercially priced gas would eliminate the artificial and continuous government intervention in gas supply, which does not promote independent market development.

What is the status of the Gas Masterplan? Is the concept of the strategic aggregator actually working?

The Gas Masterplan is well in play; there are more good points than bad. The plan was realistic – it dealt with the issues of the day. But in terms of ownership, I think the ministry of petroleum, rather than NNPC, should play a leadership role in its development. That way we have a full planning range and no conflicts of interest. If that ownership is well set then the momentum will be upheld.

Secondly, it needs to be dynamic. The Gas Masterplan is almost five years old and there might be reasons to tweak and deal with issues as they occur. If it's well resourced and placed in the right ministry, I'm sure there will be a more dynamic plan they can adjust as they go.

A gas aggregation company was well set in the plan, with the goal of having a central repository to log demand and supply. It provides a ready database for immediate and long-term gas demand, and allows any market participant to understand the domestic gas market trends.

The supply side is also improving, and eventually that aggregation almost can tell you what everybody has in what fields and areas. I think at some point the aggregation company was so overwhelmed by the increase in demand vis-à-vis supply that they almost put their arms in the air, so that needs to be dealt with better.

All said, the aggregation company as a database logging demand and supply is fantastic, but as a policy or execution instrument, may not be as effective as it could have been. Some of that is down to ownership issues, and if that is dealt with in the coming months it should make it a lot more effective.

What are the key challenges to the development of Nigeria's gas resources?

The big issue with gas generally, and I think Nigeria is no exception, is that it has to be a

market-driven development. With oil, there is a ready global market for the product.

In gas, that's not exactly the same: you start with an end market and then you develop the gas infrastructure, including extraction, processing facilities, pipelines and connecting infrastructure. All the development, including the method of transmission and distribution – be it LNG or CNG – has to be considered holistically. Any lack of integration or gaps in the process may lead to bigger challenges down the line.

Having said that, a big challenge in Nigeria would be infrastructure, because unfortunately Nigeria is not well connected or well supplied infrastructure-wise. Some parts of Southern Nigeria today are connected by a gas grid, but a lot more work needs to be done to build processing facilities as well as complementary pipeline infrastructure to ensure sustainable supply to the grid.

The presentation of the gas market in Nigeria is a significant issue. We have very prolific gas supply fields in the Niger Delta, located in Eastern Nigeria, while most of the markets are in the west and northern parts of Nigeria. A lot of infrastructure development will be required to connect these areas.

Industry-specific issues include the bankability and enforceability of domestic supply contracts as well as the price regime. The arbitrage opportunity that exists when comparing the domestic market price with the export market price incentivises producers to target the export market – especially as the credit quality of the export counterparty is superior to that of the domestic power grid, which underpins most of the domestic supply.

New domestic gas developments and LNG will happen concurrently, given that we are exporting already. It's not about starving one for the other – it's about working on both, the priority being domestic for now.

What is enabling Nigerian independents like Oando to flourish? What are the conditions that distinguish them from the IOCs?

The independents' capability to deal with community engagement challenges gives them an edge over the IOCs in the onshore concessions. It's been a very difficult area for the IOCs, and the indigenous players have demonstrated an ability to manage the relationships better.

The second point would be the economic threshold for investments. The IOCs have very structured risk and investment models in addition to operating with a high fixed cost structure, which makes small fields unattractive – the local independents are more amenable to dealing with smaller scale economics.

The IOCs, with huge portfolios of assets, go by pecking order in their investments, and may not get to those smaller-sized reserves. Given their scale and general economics they would rather start with the very big. These days, the attraction is to new markets in East Africa and Mozambique, where the finds are significantly bigger. They like scale, but the local guys should be able to deal with much smaller finds.

How can the independents raise the required finance for new projects?

So far, funding has not been a big challenge for the deals that have come to the table. The only thing that's obstructive is the limited capacity of the local financial institutions, which has meant that the acquisition of the IOC marginal fields have had to be financed in part beyond the shores of Nigeria.

Recent notable deals have been funded through a combination of local and offshore financing. Indeed, there are many financial products that can be structured to fit those projects. Our [Oando's] deal with ConocoPhillips, the OML29 Aiteo deal and the Shoreline deal were funded by a combination of reserve lending and corporate loans.

There were no significant issues with raising the finance, as the assets are well sized and there remains an interest by financial institutions in these deals. In addition, the off takers (crude oil and gas buyers) can be leveraged to augment the financing.

Nigeria's power crisis has been well reported, and LNG imports would be a good way to improve gas supply in Nigeria. What are the prospects for new facilities?

That wasn't an alternative until recently. A major driver is that the domestic market is now getting close to import parity pricing. Today, the opportunities to bring LNG to Nigeria, even for domestic use as an intervention, is now a possibility. Oando is starting to look at floating storage and regasification units (FSRUs) to assure supplies into different parts of Nigeria and West Africa, just to deal with the domestic shortfall.

I think we will begin to see new markets in Nigeria in the medium term (12-24 months) – certainly faster than we can complete field development programs that will bring additional gas to market. It's almost certain that LNG will come into the domestic gas mix in a big way in the West African region.

What are the challenges facing Nigerian LNG and Oando's ConocoPhillips acquisition?

Nigeria has had a very good run in the LNG space, with six trains developed in rapid succession and at the height of the market. There are movements in the LNG market now that make the sector very challenging, but thankfully Nigeria should be able to adjust going forward given that investment in the last few years has pretty much stopped now. So our ability to adjust to the volatility should be better.

Planned expansions and investments in new LNG projects will be difficult to justify in today's market. The global LNG market is dynamic, and with economic downturns come reduction in energy utilisation and thus LNG market activity. I would caution that we should be a bit more circumspect in our growth plans for LNG, as we may be tending towards an oversupply situation.

Nigeria is fortunate to be in a region where its neighbours are clamouring for gas for their power generation plans. We also happen to need the gas for our own power demand. I see the region and the country needs as being a natural hedge for all our LNG aspirations.

This interview was first published in Gas Matters, July 2015.

Neil Gilmour
VP of integrated gas development, Shell

With energy prices in a downward trend, upstream economics grim and carbon restrictions ramping up, IOCs are increasingly under pressure to streamline and innovate. Gas Strategies discussed the challenging business environment with Shell's Neil Gilmour, who drew on decades of experience to provide an overview of Shell's upstream operations and the future role of gas and LNG in meeting global energy challenges.

What are the main challenges facing the industry?

I would say the two C's: cost and carbon.

In terms of cost, how do we deliver gas that is plentiful? I'm a geologist, and one of the great things about being a geologist in 2015 is that the world has a lot of gas – more than we would have thought 10-15 years ago. But how can we deliver that gas into markets that need energy at an affordable cost?

And the other – carbon – is how we transition to a low-carbon energy system. That's a transition that starts now. [Shell CEO] Ben van Beurden has been talking about that. It's one of our defining issues.

Is it true that Shell is pushing for standardisation of design?

That depends. There are many cases where standardisation is the right way to go. But there are also moments when you get a leap in terms of a technology step, which changes everything.

I remember a 'eureka' conversation when a man ran into my office and showed me a well with a 90-degree bend in it. It was the first horizontal well we'd ever seen.

Or the first 3D time slice, or the first tension leg platform or the first fracked well. You have those moments when something really profound happens.

In all those cases, what happened was that we got access to more resources at a lower cost, higher value, and typically in sync with what governments and partners wanted. That's the trinity you need.

What do you think will be the next game-changing technology?

We're doing amazing things in the upstream and deep water. We're doing big LNG things – floating LNG like Prelude – and we're doing things at the molecular scale with catalysts.

With gas-to-liquids, we've got people in white coats literally scanning with electron microscopes. I like operating across these different scales.

The great thing about technology is not the development, but the implementation. It's really all about asking: "Can we get these brilliant ideas implemented and actually do something customers and stakeholders really value?" It's not about intellectual property or the incredible pile of documents that we've made. It's really about the impact.

In gas-to-liquids, we've had amazing history. It started in the lab in Amsterdam, leading to our first commercial plant in Malaysia and ends up in Qatar with the world's largest GTL plant, and the conveyor belt keeps running. We're still innovating in the lab for catalysts.

What is Shell's view on a global agreement on emissions?

Our CEO gave a great talk at the World Gas Conference that talked about the scale of the challenge. You don't want to emit carbon unnecessarily.

I think the 50% emissions gap between coal and gas is immensely important. There should be a step-change in the use of gas versus coal globally, but people are not going to do that for romantic reasons.

If coal is materially cheaper than gas, then gas is disadvantaged. We need to get more gas into the mix. We also need to work alongside a growing renewables industry, because gas and renewables are very complementary to each other: gas can provide the electricity baseload as efforts continue to improve the storage of electricity produced by intermittent solar and wind.

Can gas really thrive as a companion to renewables?

I don't see why not. Some people from the wind and solar industry may be looking at us somewhat ambivalently, but I think gas and renewables are entirely complementary – gas as both a backup for renewables and to supply a lot of energy.

There are 3 billion people today who don't have reliable access to electricity. I was back home

in Scotland recently, and if I think of having to say, "Mum, you won't get electricity at night" or "You can't keep the fridge running", that is really intolerable.

There are 3 billion of our fellow human beings who don't have that right today. So I think renewables, which will grow from a small base, together with gas, is a fantastic combination.

Which country will be first to successfully couple renewables and gas?

Someone was talking recently about Adam Smith, who wrote about the 'invisible hand' [the balancing forces of supply and demand]. I tend to have faith in that. A level playing field in terms of regulation and encouraging competition, and sensible tax treatment is right.

We certainly believe that carbon should have a cost and we detailed our view on carbon pricing in a letter to the UNFCCC executive secretary and COP21 president. We always work through governments. It's a mixture of policy and innovation and as I say, the 'invisible hand' is probably pretty helpful in that.

What is Shell's best-case scenario for the global gas market in the next five years?

We need to make sure that we get discovered resources developed and delivered in a cost-competitive fashion. My boss talks about Shell being the safest place on earth to work. That means that all staff and contractors turn up every day and go home every day completely safe.

I came to integrated gas in 2009. In Malaysia, in Sakhalin, in Qatar, we build and extend relationships that are decades long. The potential for gas demand growth is there. If we deliver gas and LNG reliably and at a competitive cost there will be demand.

We've got great colleagues in market development, including LNG for transport and some more unorthodox uses for gas. It would be great if they pulled through the supply that our teams are working on.

On the flipside, what's the worst-case scenario?

In 30 years, I don't know how many cycles I've gone through in terms of commodity prices – a whole bunch.

A lot of people have kind of apocalyptic views of what's happening. I know this [cycle] is different from previous challenges, but this industry has a brilliant record at responding.

Look at what American shale producers are doing today. They are amazingly flexible. Look at the US exporters, as well. We will get creative responses to this environment.

Do you see small-scale LNG playing a major role in the global gas industry as a bunker fuel or otherwise in the next ten years?

It shows great promise. The issue you have to overcome is not like putting a man on Mars, or some insurmountable technical issue. You've just got to have a combination of customers who will adopt it, either by switching or starting with LNG as a base – both in terms of safety and cost.

I think the scope is really substantial, especially in the marine industry. But early adopters are always going to need a little bit of courage. And if you look at road transport in China, they've gone a long way already with small-scale LNG plants and then using LNG in heavy transport.

The future will be really interesting. The defining issue isn't going to be about how to construct a small gas tank and keep it cold. We know how to do that perfectly well already.

Some say small-scale LNG faces a chicken-and-egg dilemma. Does Shell have plans to invest in it, or must that come from individual states?

I go back to my Adam Smith point: you need to create the right circumstances. If you're the first company that has fracked a well, you then want contractors to work with you. But the contractors have a dilemma: partner up with this company? Or is this a one-off? What's the scope for this thing?

You really have to convince the customers and suppliers that it is going to work.

And you can certainly talk to Chinese truck drivers today, and they'll tell you that they're very happy they've made the switch.

This interview was first published in Gas Matters, August 2015.

Betsy Spomer
President and CEO of Jordan Cove LNG

Elizabeth [Betsy] Spomer is president and CEO of Jordan Cove LNG and executive vice president of Veresen Inc. The proposed 6 mtpa LNG plant, which has secured a non-FTA export license, is one of a number of US export schemes hoping to take FID next year. In June, the Federal Energy Regulatory Commission (FERC) again postponed the environmental impact review for the Oregon-based project. Gas Strategies caught up with Betsy to find out how Jordan Cove LNG is progressing, and hear her views on the future of the LNG industry and why the US is set to reign supreme.

Have you considered an alternative business model – for example, buy-sell – similar to Cheniere, rather than a tolling model?

The primary consideration is Veresen's business model and balance sheet. For us, it's much more efficient to work on a tolling basis. I think the gas supply story is one of the strengths of this project. It's a very straightforward proposition and not as complicated as some of the projects in the Gulf Coast. We have two very large gas basins connected to existing pipelines into a part of the country with very little alternative competition for the gas supply.

Does Jordan Cove LNG need to take FID on the full four trains with a combined capacity of 6 mtpa or would you consider a more gradual build up?

I really believe that 6 mtpa is a good size to fit the current market and the timeline of 2020/21 is great for Asian markets with a lot of existing contracts rolling off around then. We have a relatively low cost phase two expansion which represents an additional 3 mtpa. It's more likely that we'll roll into phase two sooner as part of this marketing campaign versus needing to think about making the plant smaller.

What is your view on the Canadian projects? Will they go ahead?

I worked on BG's Prince Rupert LNG project and I was a big supporter and driver of that but everything looks different in a USD 115 oil price environment. If we are looking at something in the USD 70 to USD 90 range going forward then the big struggle for the Western Canadian projects is capital intensity.

Are LNG projects finding it harder to take FID?

Clearly a lot of projects are competing for limited buyer interest at this point in time, but there is incremental demand that will need to be met by new supplies early in the next decade. It's all going to be a matter of cost structure. We can deliver gas into Tokyo at today's prices for nine dollars and change. I know the Australian projects very well and Australia is going to have a hard time competing with that cost structure.

There are other places with low cost structures like Mozambique, but their challenge is the scale of the project that would be needed to justify the infrastructure required. There is virtually nothing there, so can Anadarko or ENI launch a multi train project in today's environment? I think that's a real question mark.

Do you think demand for LNG is still underestimated?

Gas is a very good solution to the pollution issues India and China are trying to address. At today's prices, US gas is competitive with Central Asian pipeline gas. I really think the development of markets like Indonesia, the Philippines and Vietnam is going to be dependent on moderately priced LNG and because of the nature of US exports; our cost structure is pretty transparent. When there is a sudden downward change in the price level demand responses are much slower than when there is a large increase. When prices go up suddenly everyone cuts back and slows down but I think we've yet to see the demand response globally for LNG based on the significant price point change that's now available to buyers.

So what are the challenges to opening new markets?

There are challenges but it has actually gotten much easier. I led BG's development of Chile's terminal at Quintero and the negotiation of the first aggregator rights in Singapore. Those were major construction projects. Now that FSRUs are becoming proven technology and you can put one in place in 18 to 24 months, import capacity has become somewhat commoditised and more acceptable. If you look at Java, where Jakarta is located, there are significant gas networks there already so an FSRU can add import capacity fairly easily.

What are the next sleeping giants of LNG? Any surprises?

After the development spree on both the east and west coast of Australia, I think everyone saw that its cost structure was getting a bit uncompetitive and started to ask 'What's next?' Clearly, East Africa has emerged as a hub but I think it has challenges, as discussed. There's Western Canada too but it is challenged by a relatively inhospitable coastline, a very capital-

intensive pipeline requirement and also a lack of clarity with First Nations about what it takes to get something permitted.

All three of these factors have dented the outlook for large west coast volumes, though I'm not by any means saying that there won't be any gas out of Western Canada. I believe the US is and will continue to be the surprise. I think everyone presumed that the US government would ration exports but it's pretty clear that's unlikely to happen.

The US gas story is going to be a long one; it's not just about the first handful of projects in the Gulf. We are going to see continued development of US LNG export projects for the foreseeable future primarily because the US has the cheapest gas in the world. It's a place you can permit facilities with a degree of certainty, it has a stable legal and political regime and there's a deep labour market – all of the things that are required for investments of this scale.

How much gas will the US be exporting by 2025?

It could easily be 65 mtpa because you can practically count that on your fingers today. But I wouldn't be surprised if we saw the development of another 20 or 25 mtpa between now and the end of the decade that would be online by 2025 – so potentially 90 mtpa.

What impact will US exports have on the structure of the global LNG business?

We've seen the emergence of people like Charif Souki, where suddenly one man becomes responsible for a massive LNG project, proving you don't need an IOC to develop one of these schemes. Part of the reason is that we've been able to disaggregate upstream development from midstream development, which makes the US projects much simpler in scope.

So how is that going to evolve? When you look at the combination of the Shell and BG LNG portfolios, you think 'wow, they are going to be up there with the Qataris in terms of market presence and impact'. But that's undoubtedly going to be somewhat diminished by the entry of infrastructure providers, like Veresen, who aren't big global players but who can provide low-cost volumes to buyers at a transparent price with no destination restrictions, introducing a degree of flexibility previously unheard of in this industry. I think there's still going to be a lot of value in the portfolio players but US exports will take quite a bit of the pricing arbitrage out of the game.

What is it like being a high-profile woman in what many still consider to be a male-dominated industry?

In the US, particularly, the natural gas side of the energy business has always been very good to women. I actually think that gas, because it is more commercially complex and therefore more relationship intensive, actually plays very well to womens' strengths. I certainly have never felt any barriers.

This interview was first published in LNG Business Review, September 2015.

Hiroki Sato
VP, Fuel Procurement Department of Jera

Jera, a joint-venture between Japanese Tokyo Electric Power Co (Tepco) and Chubu Electric, is set to become the biggest LNG buyer in the world. Once the fuel procurement businesses of the two companies Tepco and Chubu – the largest and third largest utility in Japan – have been finalised Jera's LNG demand could increase to nearly 40 mtpa. Gas Strategies catches up with Hiroki Sato, vice president of Jera's fuel procurement department to talk about Jera's pricing and contracting strategies as well as Japan's energy future.

There has been a lot of talk about the establishment of an Asian gas trading hub that would provide a regional price discovery mechanism. In a similar vein, Osaka Gas recently proposed a gas price index that would be linked to Japanese domestic electricity prices. What is the pricing strategy Jera is looking to develop?

Our target is to make the best portfolio with diversification of the price indices. In the past almost all of the volumes we purchased were linked to oil. Now not just Japanese, but also other Asian buyers are becoming more aware of the US projects and linkage to Henry Hub. There is a trend among buyers towards seeking a diversification of indices used in pricing their supply: the more traditional oil-indexation is giving way to indices based on hub prices in the US and Europe and hybrid pricing. We still have a very high proportion of oil-indexed volumes, but Jera wants to reduce this to 50% by 2020-2030. The remaining 50% of volumes would then be split – with half indexed to international gas hub prices, such as the Henry Hub or NBP, and the other half linked to Asian gas indices. Going forward, we will try to mix the three indices.

What are Jera's plans for portfolio optimisation and diversification?

I cannot give the exact figures, as we are still finalising the master plan, but substantial volumes should belong to the trading category. In addition to diversification of the price indices, we are also looking to diversify other contractual terms; in particular, the duration of the contract, as well as delivery terms, supply areas and supply countries. They will be subject to scrutiny and diversification during the procurement phase.

Jera has access to eight receiving terminals with 16 vessels. We are flexible when it comes to the gas quality (specification) we can receive – it can be lean or rich – as well as the size of ship we are able to receive (up to a Q-max). If a smaller buyer has constraints over the specification of the imported gas, the vessel size or the delivery slot, we can help. We want to become an aggregator for Asian buyers, utilising our big portfolio. That is my vision.

Do you think that the proportion of long-term contracts in Japan and Asia will decline altogether?

Yes, definitely. They will have to because of the uncertainty over future demand. Our preference is to reduce the duration of the long-term contracts, but we also have to keep in mind the development of the industry to expand the market capacity. We also have to be supportive of greenfield projects.

When looking ahead, do you believe that the current market development towards "the age of the customer" – away from a sellers' market – could reverse relatively quickly?

I don't like the terms buyer's market or seller's market. It is a buyer's market today, but who knows what will happen tomorrow? I have plenty of experience to know that it's cyclical. This is why it is important point to develop a policy and a strategy that defines your goal. We will have to come up with a policy that will innovate the Asian market and mitigate the irrational Asian premium.

How are the sellers reacting to these potential changes in contracts and pricing?

Initially there was a very strong resistance to the alternatives of oil-indexed contracts. Nowadays suppliers are also changing and starting to analyse how we might index to JLC or JKM. They are ready to discuss and introduce indices that are linked to traded hub prices. Chubu already has short-term contracts in place that include market indexation.

Who will be an attractive supplier for Japan in the future?

It depends purely on the terms and conditions offered. We currently plan to source roughly 10% from the US. Elsewhere, our choice of supplier depends entirely on the attractiveness of the terms. Our priority is how to formulate a portfolio strategy, so we do not rely on one supplier. Irrespective, we should increase the proportion of our supply volumes indexed to US and European gas prices to around 25%.

What is the outlook for Japan's gas demand given the expectation of more nuclear generation coming back online?

Gas demand in Japan will decrease as we are currently at the peak. The government's energy mix plan forecasts reducing gas demand from 90 million tonnes to 60 million tonnes in 2030. It will fall below current levels, but a reduction of two thirds is optimistic. You have to bear in mind that Japanese energy demand is not Japan's LNG demand. Japanese energy demand is lower than the demand of Japanese buyers. A significant volume of long-term contracts will have expired by 2020, which means that we have a substantial demand for contract extension. Even with decreasing demand, Japan will keep its position as the biggest importing country and Jera will keep its position as the biggest LNG buyer in the world.

There has been a lot of talk of developing a new hub in Asia, with Singapore, China and Japan mentioned as possible locations. When talking about incorporating an Asian price index to the long-term contracts, which one of them would have the most potential?

We are indeed looking to include a market-linked index, which would account for 25% of the volumes. As far as we are concerned we would link our contracts to the most transparent index. That does not need to be a Japanese index. If, for example, a Singapore index takes off then we can go with that. We would link our contracts to the most liquid and the most transparent index.

Developing the liquidity will depend on the market situation. The Asian premium will decrease next year and by 2018, three years later, Japanese and Asian markets will be very oversupplied. This will help to increase liquidity and spot trading. It would be a good support for the development of an Asian hub and its associated indices. After 2018, substantial destination free LNG volumes from the US will reach the Asian market. It is likely that this is also when Asian spot and futures exchange markets will materialise. The three hubs – Japan, Singapore and China – will likely go together.

Some market participants have been sceptical about the emergence of a physical Asian hub since unlike the geographically defined and highly interconnected US and European gas markets, the Asian-Pacific natural gas market is fragmented. Nevertheless, if and when a hub develops who will be the market maker?

I think we, Jera, will be the most promising candidate to become a market maker. Gas prices should be determined by the supply and demand balance. It's a simple theory of economics. Why should gas prices be determined by oil? Why should Japanese prices be determined by Henry Hub or NBP prices? Having said that, we have to share the risk of price volatility that is associated with hubs.

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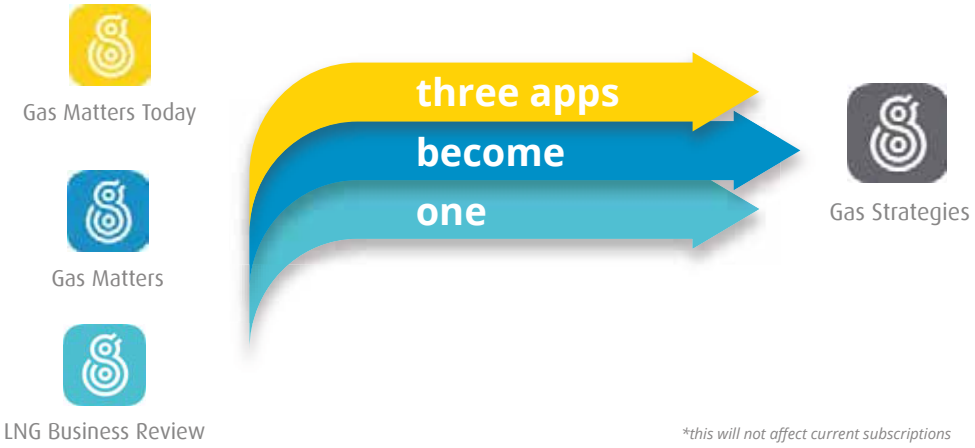

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