Gas Strategies

Essential Interviews 2017

Perspectives from gas industry leaders

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Editor's letter

The last 12 months have been defined by great uncertainty within the energy industry, from the historic Paris Agreement of COP 21 to the "new normal" imposed by a long-term correction in crude oil prices. From both a business and geopolitical perspective, 2016 was a year of adaptation to new realities. Yet natural gas and LNG still have a vital role to play – regardless of carbon-reduction policies or the emergence of "disruptive" technologies – and this will be defined not just by how the industry evolves, but by how it expresses itself.

The following Essential Interviews bring together thought leadership from a range of industry participants and commentators. Insights include the outlook for new demand and financing, emerging competition and risk posed by renewables and battery technology, new markets and applications for LNG, and the ever-evolving role of gas in the global energy mix.

If you want to have your say, please get in touch – we are always keen to hear from readers eager to participate in a Gas Strategies interview.

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Vice president of LNG
Pertamina

Indonesia – once one of the most significant gas exporters in Asia – is gearing up to become a net importer of LNG. Gas Strategies sat down with Didik Sasongko Widi, the vice president of state-owned oil and gas company Pertamina's LNG division, to discuss the company's strategy and future outlook.

What is behind Pertamina's strategy of moving from exporter to net importer?

Indonesia's demand is expected to increase significantly, driven by economic growth combined with infrastructure development. From the supply perspective, the cost of gas production from new fields is high and not economical under current circumstances.

Things have changed due to gas and oil prices, technology and the market. It now seems like importing LNG will be more economical than producing our own gas and selling it on as LNG. Also, production from existing fields has depleted naturally. In short, we predict that Indonesia will have a gas deficit by 2020.

How do the economics of importing LNG compare with producing gas domestically?

We still have indigenous projects, some of which are economical and can produce gas for less than USD 6 -7/MMBtu, but other fields are stranded, marginal and very expensive to produce from.

For example, we have potential gas in Aceh, in Northern Sumatra, but it would cost nearly USD 10-12/MMBtu at the wellhead to produce gas from these fields. Production from Java would be about USD 9/MMBtu. A joint-venture with Chevron to produce gas from deep waters near Botang is also expensive and can't be launched at least within the next two to three years.

We would still think about producing more domestic gas if the price of oil were at USD 110/barrel. People say that Indonesia has big reserves, and that is still true, but the issue is how much to produce and how much we can sell at the current oil price.

Pertamina used to be a big seller; now it has become a significant buyer. This is just how things change.

A number of Asian players have ambitions to become aggregators. Is this also Pertamina's strategy?

We are planning to become a portfolio player – to sell and buy – the same as other oil and gas companies. Domestically, we are already an aggregator as we produce gas and have the competence to sell both our own production as well as imported LNG.

Buyers come to us when they want to trade LNG. Why? Because we have the capacity, volumes and the experience in trading.

Our strategy is not only maximising the downstream sector, but also optimising the entire value chain from the upstream sector to the end user. Naturally Pertamina will become an aggregator, that's the nature of the business. Very few notice that Pertamina is already the second-biggest upstream gas player in the Indonesian market after Total and INPEX, but our production is stranded and we usually sell it to local industry.

After we take over the Mahakam block in East Kalimamtan in 2017, Pertamina will become the biggest producer in Indonesia.

Pertamina has a contract for 1.5 mtpa of LNG to be delivered by Cheniere. Are you planning to source any more gas from the US and if so, how far advanced are negotiations?

Our procurement strategy is to have our portfolio of long-term supply contracts indexed 20-30% to Henry Hub prices and 70-80% to oil. We currently only have 1.5 million tonnes of Henry Hub-indexed gas, but after 2025 we might increase our imports from the US depending on how the market develops.

It is not viable to buy LNG from the US and bring it into Indonesia before 2020, as we do not expect oil prices to recover much higher than to USD 80/barrel by then. We do not have any incentive to buy more gas from the US before then. In anticipation of low oil prices persisting, we will sell our first five years of US volumes and buy oil-indexed gas instead, under a package deal.

Having said that, we are still in discussions with other US producers alongside Cheniere, to support our strategy of 20-30% Henry Hub, 70-80% oil-index ratio in the future, but these discussions can go on for several years and it is unlikely that the deal will be reached before 2020.

Additionally, Pertamina has mentioned that it aims to source 4.5 mtpa from other international players. Where will this be sourced from?

This will be sourced as portfolio gas. I can't comment on this topic as we're currently finalising the details of the deals. We are hoping to finalise these procurement projects in 2016.

"We want to buy 70% under long term, 20% under short term and 10% as spot volumes to balance out fluctuations in our production."

Would Indonesia consider having Asian indexation in its long-term contracts?

Why would we want Asian indexation? Asian indexation is only beneficial from the Japanese point of view. They want Asian indexation because it would get them a better price. Japan and Korea have paid a premium price for their LNG, higher than anywhere else in the world. That is why they want to build their own indexation.

There is no premium any more in Japan. It seems like the push for Asian indexation is not as strong this year as it was last year.

What is your view on the development of an Asian hub? When and where would you see it emerging?

I do not think we will see it happen within the next ten years. It is unlikely to be Singapore, as its traded volumes are too small. Japan has more potential than Singapore to become a hub as it has extra capacity to sell. Japan's gas demand this year was almost 80 mt, Singapore or Indonesia could not beat that, but they could become small-scale hubs.

How many FSRUs are planned to bolster Indonesia's import capacity, including smaller terminals to service smaller demand pockets?

We are currently only planning one FSRU for our refinery in Cilacap, South part of Central Java, but at only 200 MMcf/d capacity it is not a very big one. We are also planning a small FSRU in Sulawesi.

We also have plans for mini regas terminals in Indonesia, which would support power plants in various places in Sumatera, Bali and central Indonesia, as we believe these onshore terminals would be more efficient than FSRU's, but we are still in the assessment phase.

Pertamina recently estimated that its demand for imported gas could rise above 8 mtpa. What

is driving the demand growth in Indonesia?

Economic growth is driving the domestic demand. The government estimates our annual economic growth rate at 6%, meanwhile the electrification in the country is still very low. Therefore, we believe that power demand growth will be one and a half times the forecast economic growth – meaning that the annual power consumption growth will be 9%. This is what will also drive increasing gas demand.

How much of your volumes are you planning to secure long term vs. short term or spot?

No buyer wants to be entirely committed to long-term contracts. We want to buy 70% under long term, 20% under short term and 10% as spot volumes to balance out fluctuations in our production. We currently don't have any intentions to become a big trader, but we will be buying two to three cargoes per year to mitigate risks and also to learn to show our presence in the market.

We will sell LNG if we are long and buy if we are short. If we have more LNG assets in the future, then we can become a portfolio player and an aggregator.

"We will sell LNG if we are long and buy if we are short. If we have more LNG assets in the future, then we can really become a portfolio player and an aggregator."

A number of Japanese buyers have taken equity stakes in LNG plants. Would that be something Pertamina would also consider doing?

It is too big a risk to take on a stake in a liquefaction plant abroad, we want to focus on our resources upstream and downstream, as upstream is where most of our profit comes from. Liquefaction is midstream, and as such would not fit with our strategy. That's the corporate strategy, maybe it would be something we would consider in the future, but not in the short-term.

How much of your liquefaction capacity is currently utilised and are you planning to convert any of your existing plants into regas terminals, as you did with the 12.5 mtpa Arun LNG terminal in Aceh in 2014?

The Bontang LNG plant has a nameplate capacity of 22.2 mtpa, but we're currently only utilising 11 mtpa – roughly 50%. This shows the natural depletion rate of our fields, but there is still plenty of gas around Bontang. However, ten years down the line its utilisation rate is likely to decrease further. Despite this, I don't think it will be converted to a regas facility. Bontang should still have gas available in ten years unlike in Aceh, where gas has run out.

Do you feel that Indonesia sometimes gets marginalised alongside the big buyers, such as Japan and Korea?

Our clients already think we are buyers. To be honest, we are getting approached by other Asian buyers. Two big buyers from Japan have offered their US-sourced LNG to us, but of course at the moment we can't accept that offer as they want Henry Hub-indexation. We only want Henry Hub links after 2020, it is too early for us to use HH linkage.

This interview was first published in LNG Business Review, February 2016

Katan Hirachand

Managing director energy project finance,
SocGen Corporate & Investment Banking

Enduring change has come to the gas and LNG industry. A trilemma of impending LNG oversupply, lower-for-longer oil prices and carbon-reduction policies is forcing project developers to reconsider their long-term strategies. Financing models are changing in tandem, underpinned by these new commercial realities. Against this backdrop of increasing risk, optimism remains for the role that gas and LNG will play in the future supply mix, but also great uncertainty. Gas Matters spoke to Katan Hirachand, managing director for energy project finance at Societe Generale (SocGen), and discussed the financial outlook for existing players and those looking to enter the market.

The industry is being forced to adjust to a new commercial reality and this is undoubtedly having an influence on financing models. What is SocGen's view of the situation?

At SocGen, we are cognisant of the fact that the market has changed rapidly after a long period of relatively little innovation. While the industry has had a few ups and downs, we became accustomed to a fairly rigid 'tramline' type model with identified markets and fully contracted sales. Many thought it would never change, but the fact that it finally has and the sheer pace of this change has surprised many observers.

What is also interesting is that, notwithstanding the recent falls in commodity price, it is the systemic shifts in the LNG market that are having the more profound consequences.

The market is facing structural game-changers: the future demand profile looks very different to the historical one, with two thirds of future demand coming from non-OECD countries where, in general, markets are a lot more price sensitive.

Historically, the key LNG consumption markets have been characterised by limited indigenous resources and a paucity of other options, so it's been much easier to take a 15-20 year view for equity and debt providers. But this has changed, and going forward it will become a lot harder to forecast.

The biggest development in the industry has been spurred by North America as a result of the shale boom. A large volume of gas has been sanctioned for export at breakneck speed, reversing the dynamic of the US as a huge

importer. Moreover, the 'service provider' type model is permitting destination flexibility and, of equal if not greater importance, the ability for buyers to opt out of lifting volumes on payment of a service charge. Since much of this volume is not earmarked for an end user it has led to a growing commoditisation of LNG, conferring a long-awaited flexibility on the market.

The US service-provider model is not like traditional projects where you have to take on an onerous take-or-pay liability for 20 years. You're effectively paying the cost of the service in order to have the flexibility. Such an offering also confers huge flexibility on the US in terms of being the easiest and cheapest option to not produce LNG – which is a consideration, given that the demand side of the equation is relatively stagnant. Where will all these volumes go?

There is a massive opportunity for gas, but it has to compete. Buyers, unless there is a compelling reason, are not going to need to necessarily lock in for long periods. And with the climate change debate coupled with subsidised renewables and cheap coal, the traditional model goes out of the window.

So there's a transition to a medium-term model that is more dynamic. The new demand centres are price sensitive, have alternatives, and are at different levels of maturity in terms of their environmental criteria, and LNG obviously has a role to play – but it's going to have to work against that backdrop.

That's why I think taking a long-term view on how LNG will fit in when so many things are changing is a lot more difficult.

In light of the changing macroeconomic backdrop – low oil prices and binding carbon restrictions – what are the main financial challenges facing project developers?

One critical risk the industry faces is regulatory. LNG can play an important role, in combination with renewables and other sources, in meeting the twin challenge of energy and climate change needs. But the extent to which it is able to do so will depend on the government policies and their stability and predictability. We should not overlook that LNG still represents the cleanest fossil fuel.

It's important to note that lenders have provided very strong support to the LNG industry based on strong sponsors, buyers and long-term contracts. But first and foremost we look at the fundamentals – is there an assured market at prices that support the investment and its finance, and is it competitive?

"Keeping it a well-defined, skinny, digestible story for the market is probably the best advice I can give. After all, small is beautiful!"

We believe there is an important role for LNG and that lenders will find ways to support the best projects; but it will need creativity from project sponsors and lenders to accommodate these new dynamics.

For development projects, securing a set of markets strong enough to underpin the investment with all the attendant risks is key – this should lead to sellers and buyers working together more closely to share the risks across the chain – this approach will increase the chances of more projects getting sanctioned.

When prices are depressed, the value proposition for equity and debt is impugned so the 'problem' has to be broken down into smaller, more manageable pieces.

For developers wishing to secure debt, their biggest challenge will be to convince lenders that the newer buyer profiles are sufficiently robust – that they have the ability to pay for the LNG long term; that they've got the underlying demand; that the LNG stacks up from a competitive cost of supply view in that market; that they've got the infrastructure; most importantly that they've got the regulation fostering and promoting the development of natural gas in that country – all of that I would group as one key challenge.

The cost-competitiveness of the project will be another key metric for lenders – no one wants to lend to the highest-cost project, so ensuring there is ability to weather transient periods of volatility

and that the cost stacks up vis-a-vis other projects is another key metric.

Another obvious one today is the commodity price, because a lot of these projects are predicated on higher commodity values and without those it's quite hard to get the sort of leverage that people are looking for from a debt-to-equity ratio perspective. But I think that underlines one of the key themes here, which is how you work to get your costs down. If you're able to get your costs down then clearly you'll be able to support the prevailing commodity price environment more.

You can have formidable buyers, but if you need a very high oil price to break even that doesn't provide a lot of comfort. So it comes back to project fundamentals. If I'm going to lend you money on a long-term basis that is effectively non-recourse, I need inherent comfort in the economics of the project and insure that on whatever metric you want to use – cost per tonne or break even – it's sufficiently low to retain its competitiveness in periods of market volatility.

What advice would you give those looking to enter the industry right now?

Keep it small, lean, ultra cost competitive if possible. Phasing and sharing of costs where possible will also help. Work to keep projects manageable in terms of size, investment and market acceptability and be prepared to give a little bit more of the value up at this point in order to get off the ground.

That will resonate with the market because it's simply more credible under the circumstances – especially when coupled with the market changes I've outlined. If the project can be made to work using the European spot market as 'market of last resort', it should be in good shape.

People keep asking when the pendulum will swing back to suppliers. It would be nice to see a more balanced picture, but the magnitude of investments make the business a lumpy, irregular one.

Clearly, if we start seeing more projects deferred, we will eventually go back to the rush we saw in the last decade to bring new supply online and the concomitant 'overheating' of the market.

As I said, it would be good to avoid these 'extremes' and if the industry can get the fundamentals right, maybe the extreme will be less severe. Keeping it a well-defined, skinny, digestible story for the market is probably the best advice I can give. After all, small is beautiful!

This interview was first published in Gas Matters, March 2016.

"You can have formidable buyers, but if you need a very high oil price to break even that doesn't provide a lot of comfort."

Ben Caldecott
Stranded assets programme director
University of Oxford

The energy landscape has never been more uncertain. Producers of all stripes are looking to secure their position in the future energy mix and convince investors that they are indispensible to meeting energy demand and tackling climate change. Gas Strategies spoke to Ben Caldecott, director of the stranded assets programme at the University of Oxford's Smith School of Enterprise, to discuss the challenges facing the oil and gas industry in a carbon-constrained world, and whether the environmental lobby should face facts on the role of natural gas as a transition fuel.

Has the oil and gas industry underestimated the environment-related risks of 'business as usual'?

Very much so. These factors are new, complex, the data is sparse, and the risks are non-linear. You can see this in some of the scenarios that are published by the oil and gas industry; like many other organisations, they have underestimated the pace at which renewables and related technologies have been able to realise cost reductions and be deployed at scale.

I think they are severely underestimating the potential of electric vehicles to change markets and destroy oil and gas demand in the future.

Even at the best of times, relatively simple risks can be mispriced and known risks can be left ignored. This is often because of biases, misaligned incentives, and endemic short-termism. These problems are exacerbated when the risks in question are novel and where the data, analytical tools, and methodologies are missing. Add to the mix a lack of viable options to hedge risk, and there is plenty of scope for markets to be getting risk management wrong. This is exactly what is happening with respect to environment-related risk.

Investor activism on climate risk has become a common feature of many company AGMs now. Do you think that the IOCs are out of step with their investors?

I think they misunderstand and underestimate the extent to which investors are going to be engaging with them and piling on the pressure. Active ownership is becoming more sophisticated and it's becoming more mainstream. This is particularly the case in Europe, which is now catching up with the US. They're going to have to respond in much more sophisticated ways than they have so far.

I think there's a question about the business

model, not necessarily because of climate change, but because of structural issues in the upstream oil and gas business.

If reserve replacement ratios are a key measure, how on earth are IOCs going to keep succeeding in the context of massive national oil company (NOC) competition? They're being squeezed into very high cost, difficult places and clearly low oil prices make that uneconomic. And if you consider demand destruction and structural changes in the oil market as a result of energy efficiency and electric vehicles (EVs) and so on, there's not a huge opportunity for growth.

"The IOCs have got some big choices to make and it's not just to do with climate change. It's to do with NOC competition and the price of oil, rather than anything to do with carbon budgets."

I would argue that the IOCs are in a position where there aren't very many, if any, attractive investment opportunities. There's a tendency to invest to get your reserve replacement ratio to a better place, even though it's not going to be a very good investment opportunity because it's expensive.

What kind of environment-related risks are the IOCs exposed to?

These risks manifest themselves in different ways, in different markets and in different parts of the value chain. There's tightening environmental regulation, whether carbon pricing, emissions trading or pollution standards. Generally, once such regulations are introduced they are strengthened, and once they're introduced in one place they tend to get adopted elsewhere. So what we're seeing is an expansion and deepening of the stringency of environmental regulation.

In addition, sustained policy support for renewables has been bearing fruit in terms of massive cost reductions. The power system is in a state of transformation and energy storage will accelerate that. EVs are part of that story. I don't think any of the IOCs are yet in a good position to grasp those opportunities.

One of the areas we look at is social norms and the divestment campaign is an example of that. People's views are changing. When I talk to senior oil company executives, they say that divestment doesn't matter, but now they're having difficulty recruiting good people. They're beleaguered by the fact that they're in a stigmatised industry – that would have been different five or ten years ago.

Another is litigation and liability – could these companies be sued for damages? For causing climate change? For not disclosing material information to markets? For not appropriately managing climate risk and getting taken to court for that?

These are all areas that the Bank of England has highlighted as potential issues. They might feel a bit far removed, but given the subpoenas of ExxonMobil and Peabody in New York last year regarding climate change disclosures, these could significantly affect companies in the medium to long term.

Has the Paris Agreement made any difference to the severity of these risks?

A lot of the risks that are material have got little to do with COP21 or the Paris Agreement. Take technological change – yes, it's connected to policy, but it's not just happening because of a climate change agreement at an international level. It's happening because of concerns about air pollution, in the case of EVs in China or indeed Europe. So the vast majority of the drivers will happen regardless of whether there's a climate agreement in place or not.

Obviously, having a robust international framework is still important and useful. It helps to ensure consistency and can help provide important high-level engagement and a sense of direction globally.

But oil companies do have a tendency to use the climate change agreement as a straw man. They say that the Paris agreement has no bite, or that it's insufficient or it's never going to be applied properly internationally in a coherent way – therefore it's not going to affect their business.

But we're not claiming that the international climate process is suddenly going to result in a massive loss of value. That's a very unsophisticated view. It's the sort of view that some of the NGOs use. What we're seeing is that there are a whole bunch of factors, and climate policy at an international level is one of many.

You can't hide behind your scepticism about the global climate change agreement. It's not all about 2 degrees and cap and trade, which you may or may not think is material.

The IOCs have put a lot of emphasis on the role of natural gas as a low-carbon transition fuel. Does the environmental lobby need to face facts about the need for gas?

If we're going to achieve 2 degrees, we need a net-zero carbon emission power system by around mid-century. Now, gas is still very carbon intensive, even more so depending on your view of fugitive emissions from methane. Coal with carbon capture and storage (CCS) and gas with CCS generate positive emissions. So you'd be constructing and expanding infrastructure that is incompatible with the need to be net zero.

If you're concerned about climate change, you've got to understand that cumulative emissions are the issue and you've got to manage that. That means that the flow needs to get to zero and gas does not help with that. If it's a bridge then it's actually a very short bridge.

Using a lot of gas for a long time is not compatible with net-zero emissions – but there's a question about whether we're going to do net zero, whether we're really going to deal with climate change in a timely fashion.

Unfortunately, there's a strong chance that we won't. So a more honest answer from the oil and gas majors would be that they don't actually think that the governments of the world are going to deal with climate change and they don't think that the energy system is going to go to net zero, so they think that there's still a big role for oil and gas. To be fair, that is now what Shell and others have started to say.

Can you see the IOCs returning to low-carbon technologies such as renewables or CCS?

The IOCs have got some big choices to make and it's not just to do with climate change. It's to do with NOC competition and the price of oil, rather than anything to do with carbon budgets.

They've basically got three options. The first choice is that they do a run-off strategy. They don't chase dividends, they don't try and replace reserves, they're very capital-constrained and they just try to get money back to shareholders over a 20-year period. But you wonder whether IOCs are prepared to appoint people to spend their careers winding down their industry. That seems unlikely.

The other option is diversification. But the idea that because they're in the energy industry they're well placed to do renewables is wishful thinking. They're just as well placed to do anything else. The question is how do they diversify and do they get investor permission to do that? How will that affect the yield profile for example? Will they do a Nokia, and evolve into something completely different? That also seems quite unlikely.

"Active ownership is becoming more sophisticated and more mainstream. This is particularly the case in Europe, which is now catching up with the US."

The third option is not doing anything. In which case, these companies, which are already borrowing a lot of money to sustain dividend payments, are going to be in deep trouble. But that happens in the constant process of creative destruction that drives our economic system forward. Big companies fall away and other big companies take their place.

This interview was first published in Gas Matters, March 2016.

Ed Davey

Former UK energy secretary and Liberal Democrat politician

The challenges facing the gas industry are no better typified than in the UK energy sector, where – despite vocal backing from the Conservative government – gas has failed to gain the financial incentives necessary to spur the construction of new-build CCGTs. With the UK carbon capture and storage (CCS) competition scrapped and capacity market auctions incentivising coal and diesel over gas (despite government plans to phase out coal), it is uncertain how gas can strengthen its role in the mix. Gas Strategies spoke to Ed Davey, former UK secretary of state for energy and climate change and Liberal Democrat politician, and discussed these issues in light of the carbon-reduction pledges made at COP21.

How can gas continue in the long term without CCS technology – not just in the UK, but globally? Will emissions targets have to be ignored?

For anyone to build a CCGT they need to believe they'll get back their investment with a return over, say, 15 years. At the moment they can't see how they can get that in the UK electricity market and there's a whole set of reasons for that. One is the impact of renewables and nuclear, which are depressing the wholesale price because they can charge at low marginal cost.

Interconnectors also depress the wholesale price and it's increasingly clear that, if you're a gas investor, there's no way you're going to invest in a gas plant based on the wholesale price of electricity.

This means you need payments outside the wholesale market – that was the whole rationale for the capacity market. And it's increasingly clear to me that capacity market contracts are going to have to deliver the full cost of building, with a return over 15-20 years, if investors are to back new CCGTs. Investors increasingly have a view that they cannot factor into their analysis very much, if any, revenue from the wholesale electricity market. And that's the way the UK government is going with its capacity markets reform consultation.

I broadly agree with a lot of what's in that consultation. The problem is that it's very much a "work in progress" – and they've missed a whole set of things in that consultation. So they're going to have to revisit it once they've got next year's auction out of the way.

The consultation isn't as upfront as it should be on one key issue – that we're going to have to subsidise gas power generation a lot. But, of course, it does say that we're going to buy more capacity than we need – i.e. the price is going to be driven up artificially.

That means the consumer will have to give higher-than-needed subsidies to gas, which goes to my point: for a gas investor to invest now, they're going to need all of their return to come from subsidy. That point, which I consider almost an empirical fact, has been lost on the public debate. No one in the papers is saying it, but that's what the consultation is really saying.

The Tories are nervous about saying it because they've been bashing subsidies for renewables for a long time. The truth is they are reducing subsidies on renewables, which are coming down in cost, but I think it's ironic as they'll have to bring in very high subsidies for gas.

So how can the capacity market's shortcomings be addressed to incentivise new CCGT build? What's the next step?

In the short term they're doing the obvious thing, which is to buy more than they need to push the price up. That will create an incentive. In the long term that doesn't look terribly sustainable because they're having to buy a lot of nuclear and indeed coal and diesel, when what we really need is gas. So they're giving subsidies to nuclear, coal and diesel, which you don't want to do.

When we designed the capacity market, I told my officials: "I don't want to give any subsidies to non-gas industry". The response was: "Minister, to get the state aid clearance you need to be technology neutral".

So I've been saying for some time that the British secretary of state needs to go to Brussels and request the ability to favour gas only in the capacity market. Otherwise, we're going to keep getting perverse results where we're over-subsidising existing nuclear and giving subsidies to technologies that are counter to our EU-wide agreements on decarbonisation. One policy is taking you one way, and the other is taking you the other.

The EU is going to have to take a different view on state aid in relation to capacity markets.

There was a very important and unreported speech by EU climate action and energy commissioner Miguel Cañete on 3 March this year, where he talked about an EU approach to capacity markets and developing an EU framework for thinking about them. He set out a number of principles – one of which was to ensure that any framework that brought on new capacity was in line with the decarbonisation objectives of the EU.

Now there's a hook for a British minister to redesign the capacity market by going to Cañete in Brussels and saying: "You've got to allow us to have a gas-only capacity market". I'm sure there'll be a major reaction by diesel, coal and nuclear, but I think there's a very strong argument for it. And we need to talk to Europe about that. Building on the commissioner's speech, there would be an appetite for it.

Current UK energy secretary Amber Rudd said Brexit poses a threat to solidarity against Russian supply dominance. Surely an independent Britain would be able to develop a more diverse security of energy supply?

While I agree with her, I don't think she explained it terribly well. Europe wasn't talking about energy security until Putin invaded and annexed the Crimea. When that happened, everybody panicked about Russia abusing its energy interests to dependent countries like Hungary, Romania, the Baltic, Slovakia and Poland.

At the EU energy council, Britain was the leading advocate of an EU-wide energy security strategy to take on Russia. The best way to defeat Putin's aggression is not through building up the military but through attacking him where it really hurts: in the pocket.

What the Saudis have done with the price of oil has probably now had a bigger impact, but at that stage the oil price hadn't fallen. My objective was to reduce

"The consumer will have to give higher-than-needed subsidies to gas, which goes to my point: for a gas investor to invest now, they're going to need all of their return to come from subsidy."

Europe's dependency on Russian oil and gas through energy efficiency, through renewables, through LNG terminals, through gas pipelines to import/export gas more efficiently across the whole of Europe, so that as a European Union by 2030, our strategy was to reduce imports from Russia by about 15-20%. A big impact on his revenues.

That soft power that Britain has in the EU, to be able to lead on the European energy security strategy, we would not have if we were outside the EU. I published a long paper and circulated it to the Commission and member states on an ambitious EU security strategy, and that British paper was extremely similar to the one that later came out of the Commission and was agreed by the EU.

If we weren't at the table we would not have that influence: we would lose that soft power. Arguably, such power is more effective than spending tens of billions of pounds on weapons, because it stops the Russians spending all the money they'd have got from those exports on weapons. The best way to tackle Putin and Russian aggression is to not depend on them so much for energy.

What impact do you think Brexit would have on the UK's energy sector?

In the short term the impact would be relatively small. There will not be a cataclysmic disaster overnight. But over time Brexit would most certainly undermine our economy, our social support, Britain's impact on climate change, it's soft power… over time Britain would be a less influential, prosperous and secure country.

In terms of energy policy, first of all the 2020 targets for renewable energy could be scrapped – I think that would be a mistake, but they could be. The 2030 target, which I negotiated, is totally in line with the climate change act of the UK, so that would make no difference.

"There will not be a cataclysmic disaster overnight. But over time Brexit would most certainly undermine our economy, our social support, Britain's impact on climate change..."

The real detriment would be in our inability to lead on the single energy market, our inability to influence policy on the interconnectors, our inability to influence all European-wide strategies – be they on climate change, energy security, affordability. By not being at the table, we couldn't influence other peoples' policies.

When I was secretary of state, I created something called the Green Growth Group (GGG), which was a group of member states that shared our view on climate change. Through the GGG, Britain led on brokering the 2030 package, which ensured that all EU members had to be more ambitious on climate change and share the UK's ambition. The 2030 package that we negotiated, because we were in the EU, effectively Europeanised Britain's climate change act.

So this is the real issue. Issues like energy security and climate change are not simply for the UK by itself – they are international issues. You cannot see them as an isolated island – if you do, you will have worse outcomes. So by being in the EU we can help influence the whole energy market across the EU, the whole of climate change and security policy, and punch above our weight. Outside we have no voice and no vote.

It would therefore be a huge strategic error and damage British energy companies severely – in the long term.

This interview was first published in Gas Matters, April 2016.

Ajay Shah
Vice president, developing gas markets
Shell

Ajay Shah leads a global team responsible for gas market development from the regasification terminal through to the local downstream market. He has worked in Shell's gas and power division for more than half his career and was part of the team responsible for the successful start-up of Hazira, Shell's LNG re-gasification terminal in Gujarat, India. Prior to his current position, Ajay was vice president, ventures west within Shell's integrated gas business. He was responsible for gas value chains in Oman LNG, Nigeria LNG, and the European Gas arena. Gas Strategies caught up with Shah at Flame 2016 in Amsterdam and discussed the outlook for global gas markets against a backdrop of burgeoning LNG oversupply and increasing carbon regulation.

What are your responsibilities at Shell?

I'm focused on the development of gas markets – markets that have indigenous gas production and will need LNG in due course, or where there's never been significant gas consumption. So there are two dimensions to my role: one is how to bring LNG to a market that is already using gas, and the other is how to develop a market that hasn't really used gas before.

Part of the history of a company like Shell is that we've seen many evolutions of gas market places around the world. We think we have a role to inform and explain how these things work.

There's such a surfeit of knowledge that, firstly, you want to bring people up to speed as to how it all fits together but also inform them of the risks and the challenges – that it is capital intensive, but that the benefits do accrue over a longer period of time.

What is your view of the current market?

We're at a bit of a crossroads right now. It's a changing environment both in terms of supply-side and demand-side dynamics. There are two extreme end points: one where the US changes the dynamics of the gas market completely and results in a whole new normal, versus another extreme, where the great cycles of the past 15-30 years simply continue.

The reality will most likely be something in between – as it was ever thus – and I think there are a number of similar markers of the current reality on which you can reflect back in time.

There are some structural pieces that are different relating to shale gas in the US, in particular, but there are lots of things that are the same – the access to capital; the absolute cost of our value chain; the relative lack of fungibility of this product versus more traditional energy

products; the fact that transporting gas across the world is a big chunk of the cost in the value chain.

So there are lots of things that are the same, but a few things that are a bit different.

Are you seeing more difficulty for new projects to secure finance?

I don't think it's any more or less difficult than it has been. It's always hard to put these things together; they're complicated, big-value integrated projects that tend to have lots of dynamics around them.

For example, a particular project in a particular part of the world with government backing will have a very different dynamic to a purely privately driven tolling-type model.

The cost/demand/financing triangle always ends up being a factor in new projects, because ultimately we're talking about billions of dollars of investment. To make a decision, you need to have many of those pieces together. They don't all have to happen perfectly, but they do eventually need to come together.

Where do you see the biggest opportunities for new demand?

Rather than picking a country, let me talk more about regions. The "other Asia" has a very interesting dynamic. We've historically looked at Japan/Korea/Taiwan as the main gas markets, and now India and China have emerged. They remain the elephants in this room, but there's a whole bunch of other emerging markets.

Singapore is one that's already down the road; Malaysia and Indonesia are on their way up and then you have the next ones: Vietnam, Myanmar, emerging economies that are hungry for energy, but which tend to burn oil today with coal also in the mix.

These are areas where gas can make a huge difference – not only in terms of cost but also in terms of air pollution reduction. In these markets it's such a big issue. You walk around the streets of Jakarta or a large city in China and it's tough. If you can do anything to clean up the air quality – and gas can help here – then clearly you can make a big difference to people's lives.

An additional benefit of switching to gas is that it will of course displace higher CO2-producing hydrocarbons.

What other regions are you focused on?

In North Africa, Morocco is starting to think about LNG imports. In East Africa there have been some big gas discoveries and developments, but there also needs to be a domestic marketplace developed in Tanzania, Kenya and Mozambique.

We've always thought of South Africa as a place where gas markets could take off, because it's such a big coal user. And then there's Ghana, the Ivory Coast – even Nigeria is thinking about how can it bring gas to places that are remote from its relatively sparse pipeline connections.

"I'm a gas guy and I've been doing this for 20-plus years now, and from my perspective this is just another cycle. It has slightly different characteristics, but the best cure for oversupply is low prices. The market eventually balances out."

On the other side of the world, we're looking at many locations in South America. Brazil is probably one of the most interesting but also the most challenging markets, because it's primarily a hydro-based electricity market that you need to be able to balance with gas. But there are also places like Chile, places in the Caribbean and Central America, but also in Uruguay and Argentina – so there's a lot of scope for developing gas markets.

What characteristics do you look for in target markets?

There needs to be some kind of energy dearth. There needs to be latent demand that's unsatisfied; a generally growing economy – and almost everywhere in Africa is like that – and an understanding

of the bigger energy picture – of how the pieces fit together rather than just wanting to buy and consume. And there needs to be really strong government support, including support by the NOC and the ministry of energy, because these are complicated chains to put together.

I think back to Europe in the 1950s when governments and companies were thinking about how to develop a gas market – first of all country by country, and eventually how they were going to connect. There need to be some similar efforts in parts of the developing world.

How do you decide on the best route to monetisation?

It depends on scale – so if the discovery is enormous, Mozambique-style, then all options are on the table.

If it's smaller, then you probably need to think about how you want to make maximum economic use of the resource, which might mean some gas to shore in the first instance and some kind of export play to generate revenues, and then see a vision of that becoming much more domestically focused.

The problem is that these are 20-30 year timeframes, so how do you help a government to understand that?

Do you see the LNG oversupply situation as a long-term problem?

I'm a gas guy and I've been doing this for 20-plus years now, and from my perspective this is just another cycle. It has slightly different characteristics, but the best cure for oversupply is low prices. The market eventually balances out.

So I don't think the dynamics have changed. The long-run marginal cost of producing LNG is not significantly different today to a few years back. There are cost challenges in our industry that we really need to address, but people talk about oversupply forever and I'm not one of those.

On the basis of the flexible Intended Nationally Determined Contributions (INDCs) submitted at COP 21, will we really see an end to fossil fuel burn and a huge ramping up of renewables – or are they simply opening the door to energy pragmatism?

I think there will be a place for hydrocarbons for a long time to come. I joke about it being "not in my lifetime, perhaps not in our children's lifetime", but I hope that in the end we get to a zero-carbon future. But how we get there and through what mechanism is uncertain, and of course the big thing is carbon capture and storage (CCS) from a hydrocarbons industry perspective.

We talk about a price for carbon at Shell. We believe it is an important way of driving behavior, and that it will lead to the ability to say: "This is the target for which you need to make CCS work". And that drives all kinds of innovation. We believe there is a solution; we just haven't got there yet.

This interview was first published in Gas Matters, May 2016.

"We're at a bit of a crossroads right now. It's a changing environment both in terms of supply-side and demand-side dynamics."

Kevin Ramnarine

Former energy minister of Trinidad and Tobago

Trinidad is the world's sixth-largest LNG exporter, but production from its only liquefaction facility – the four-train 15 mtpa Atlantic LNG plant – faces a gradual decline as reserves deplete. Gas Strategies caught up with Kevin Ramnarine, Trinidad and Tobago's (TT's) energy minister 2011 to 2015, to discuss his tenure and the future outlook for Trinidad's gas production and LNG exports.

Why is Trinidad's gas production decreasing and what strategy does the country have to boost falling production?

Sliding production is a result of a period of underinvestment from 2008 to 2010. Gas production decline started around six years ago and has become progressively worse over time. We saw increasing gas curtailments in 2014 and 2015, but I expect 2016 to be the worst year in terms of the gas shortage. Output from Atlantic LNG should be around 2.3 Bcf/d to cover its contractual obligations, but it is currently at around 1.7 Bcf/d.

It was clear in 2011 that there were not enough incentives for IOC's to invest in Trinidad. Our fiscal regime was not competitive compared to Azerbaijan, Angola and the US Gulf of Mexico. The world had changed and we realised that we also had to change to be more competitive to attract more investment. This was the fundamental philosophical change in the governance of the oil and gas industry during my tenure.

As a result of a better investment environment, companies started investing again in 2012 to 2013, and by 2014 BP had sanctioned its largest ever investment in Trinidad – the Juniper [offshore gas] project. The investment in the Trinidad upstream has continued in 2015 and 2016, while everywhere else in the world funding was cut.

We should climb out of this hole as things will gradually start to improve over 2017 to 2018, with four new projects coming online around that period.

The Juniper offshore project [comprising two fields] will add 590 Mcf/day in Q3 '17, while BP and EOG Resources' joint-venture at the Sercan gas field will add 275 Mcf/day.

Additionally, the Trinidad regional offshore (TROC) project allows us to get more gas out from BP's existing wells and BHP Billiton is developing the Angostura Phase 3 field. These four projects should add 1.1 Bcf/day to Trinidad's production, about 30% of our current production. This is good news for our LNG, methanol and ammonia producers, who have been suffering as a result of five years of curtailments.

This doesn't solve the problem though. While we are bringing on new gas, existing reservoirs are declining at the rate of 15-20% per year. We are playing catch-up to bring new gas into the system and in the long-term Trinidad has to look at ways of incentivising upstream investment, including

options for developing our cross-border reserves with Venezuela.

Can you elaborate on the Venezuelan developments?

We have been in talks with Venezuela since 2003 about developing our cross-border reserves. There are three cross-border reserves, the largest of which is called the Loran-Manatee field. Loran is on the Venezuelan side, while Manatee lies in the Trinidadian waters. Chevron is a very important player for this development as it is involved in both sides of this field – in Venezuela, as well as in Trinidad.

When I was in office, I worked very closely with Ali Moshiri, Chevron's President of Chevron Africa and Latin America Exploration and Production, as well as with the Venezuelan energy ministers. Our governments came up with a unitisation treaty, but the companies involved have yet to come up with their own unitisation agreement, to be followed by the development plan which has to be approved by the ministers of both Venezuela and Trinidad. I think that gas from the Loran-Manatee field could flow as early as 2021. It will be a milestone for the industry when that happens.

"I am a great believer in privatisation, and if I had continued I would have recommended an initial public offering (IPO)."

Venezuela is also developing its Dragon field and has approached Trinidad recently looking at ways to export gas production from this field. Dragon could be linked to Trinidad's infrastructure by a 15-mile subsea pipeline. This concept has been widely used for cross-border export options in Asia, Europe and elsewhere so there is no reason to believe that it would not work. Venezuela is also looking at options for exporting LNG via Trinidad.

However, a number of questions still need to be answered before the Dragon project can progress, such as who is paying for this, how much gas are we looking at and who would be the potential Trinidadian customers for this gas?

Venezuela is cash-strapped and is in a situation where it could face a possible default on its international bonds. However, we have seen some Russian companies getting involved with this project, so it seems to be moving in the right direction.

What impact has the low oil price had on Trinidad and Tobago?

In 2015 drilling activity in TT increased, while everywhere else in the world it went down. Good fiscal incentives as well as strong relations between the government and the IOCs were the key reason for this. The incentives we have provided should help buffer companies against the falling oil price but more work may be needed to protect them.

The price environment will have an impact, but companies have already made capital commitments long before the oil price fell. BP is continuing its investment and has said that Trinidad is one of the few places in the world where it will increase its investment.

There is also a lot of optimism around Trinidad's deepwater campaign. BHP Billiton started drilling in the Trinidad and Tobago Deep Atlantic Areas (TTDAA) in ultradeep water in excess of 1,000 metres this year and I feel confident that they will be successful. I was pleased to be part of this exploration campaign having signed all nine deepwater production sharing contracts between 2012 and 2014.

What strategy should Atlantic LNG pursue in its impending contract renewals?

The Train 1 LNG contract is coming to an end in 2019. My government started talks with BP on the renewal of the Train 1 contract, which is a very important for Trinidad.

My position on what we would like to see as a country in the renewed Train 1 contract is very clear. I would like to see the increased participation of Trinidad's national gas company NGC in the Atlantic LNG joint venture through higher equity and offtake. NGC currently has 10%

of Train 1, which is too small. I would like to see that percentage increased to 20% or more. NGC currently has no offtake from Train 1, so I would also like to see an increase in their offtake. NGC has to have a bigger marketing portfolio in LNG.

I am a great believer in privatisation, and if I had continued I would have recommended an initial public offering (IPO) for NGC as was done with its subsidiary Phoenix Park Gas Processors Limited in 2015.

From our perspective it has been proven that the spot market offers a more lucrative price. When NGC began directly supplying the market we were able to earn better revenues by selling cargoes on a spot basis rather than via long-term contracts. But this depends on whether the market is over or undersupplied.

What will happen to the market for Trinidadian LNG beyond 2020?

TT could emerge as a processing hub for gas and oil in the future, as oil has been found in commercial quantities by Exxon in Guyana and Tullow Oil and Shell in French Guiana There's also Venezuelan gas all around Trinidad, especially in the area called Platforma Deltana, which is estimated to hold over 30 Tcf of gas.

"I still see Trinidad as a global LNG player in five years. We will remain competitive and keep our position as the sixth-largest exporter, despite the new capacity coming onstream."

Trinidadian plants are running at 80% capacity. Venezuela needs money and Trinidad needs gas, so it seems like a good match. In the future we will inevitably move into the direction of co-operation, but of course the devil is in the details and we have to iron out all the arrangements beforehand.

I still see Trinidad as a global LNG player in five years. We will remain competitive and keep our position as the sixth-largest exporter, despite the new capacity coming online. We are currently supplying 15 markets, including some Asian customers, but with the rise of Australian supply, our customer base will retreat to the Americas.

In the long-term, I hope to see Trinidad keep its competitive position, increase its supply to the Caribbean and NGC to have a bigger footprint in the LNG business as well as an international portfolio of investments.

This interview was first published in LNG Business Review, June 2016.

Tom Strang
Senior VP of Maritime Affairs
Carnival Corporation

Carnival Corporation operates the world's largest cruise ship fleet of 100 ships, consuming more than 3 million tonnes of marine fuel and visiting more than 700 ports around the world. A total of 15 new ships are scheduled to be delivered to Carnival Corporation between 2016 and 2020. In 2015, the group's revenue totaled USD 15.7 billion. Gas Strategies caught up with Tom Strang, senior VP of maritime affairs who is developing Carnival Corporation's LNG strategy.

What is your role in Carnival Corporation's developing LNG strategy?

About 75% of my time is spent on our LNG strategy and ensuring that there's a supply chain in place for our vessels that will be able to utilise the cleaner solution. Four of our next-generation cruise ships on order will be the first to be powered by LNG both at sea and in port, so my job is critical to make sure the fuel will be available once the ships are delivered.

We are evaluating new and established technology solutions to reduce our air emissions and improve air quality, and because of its reduced carbon and cleaner emissions, LNG has been a big focus for us as of late. And I am helping to drive that charge.

The environmental benefits of LNG, in combination with regulatory and supply chain factors, were a tipping point for us to begin the transition to build the world's first LNG-powered cruise ships.

AIDAprima, the latest and most environmentally-friendly ship from our AIDA Cruises brand, is the first cruise ship to use LNG in port and is currently in operation in the North Sea, calling at five different ports between Hamburg, Germany and England.

The ship has one dual-fuel engine, but because there is currently no storage on-board for LNG, our team has been helping to secure LNG at each of the ports at which it calls.

We had originally planned to use ["China's"] ENN for the procurement of the fuel, but in the end they pulled out of that kind of market in Europe, so we had to work quickly to find another supplier and in the end went with Shell.

By 2019, we will be the first cruise ship company to use LNG to power our ships when they are both in port and at sea – for their normal operation – with the four next-generation cruise ships beginning to join our fleet (two for our Italian-based Costa Cruises and two for our German-based AIDA Cruises).

What is the business case for Carnival switching to LNG?

The environment is extremely important to us and we are committed to protecting it. In 2015, we developed rigorous sustainability goals, which we are working to achieve by 2020, and LNG is

playing a critical role in our goal to reduce our emissions profile.

As we've said, we're looking for new platforms with new opportunities. That gives us a chance to revisit the traditional fuel approach. When we looked at this, we felt LNG offered a good alternative and these are our first steps.

AIDAprima and its sister vessel AIDAperla were contracted at a time when the rules really wouldn't allow us to have tanks inside the vessels. We could have perhaps had external tanks, but that wasn't a feasible option, so we decided to target in-port operation. Now we've done that and the next step is to go to a full gas-fuelled vessel.

In that respect, when we looked at LNG, we felt it was the right option. We had a very proactive partner at the German shipyard Meyer Werft that was prepared to introduce leading-edge technology and we had a regulatory framework that gave us the confidence to proceed.

In your view, what are the main obstacles to LNG bunkering now?

If you think about traditional bunkering hubs like Singapore and Rotterdam, where you have large cargo vessels in operation – today you can pick up fuel wherever you like. You can go to almost any port in the world and buy gasoil or IFO 380 [Intermediate Fuel Oil].

With LNG, that's not the case. We'll have to build that supply chain in most cases. But I wouldn't say that's an obstacle; it's an opportunity. It's a challenge.

We have to find a way to be able to do it and we're going to be at the forefront of establishing LNG as a trusted power source. And from there, building out the supply chain for it so that it is easily accessible for not only our fleet, but the industry as a whole to better the environment.

Currently, we see more and more infrastructure being built in northern Europe. We already know that on the route AIDAprima has taken, two ports already have LNG bunker barges slotted for deployment. So that's one element – building that supply chain.

On the regulatory side, we've seen a lack of uniformity in regards to its application to bunkering. That needs to be worked on, and that's what organisations like SGMF, the ESSF [EU Sustainable Shipping Forum] and others need to do – make sure that those hurdles are not insurmountable.

In our experience, we've found with AIDAprima that – and this was only truck-to-ship bunkering – the ports have very different approaches to regulation. The fundamentals are the same, but you have various countries where permitting is a very bureaucratic process.

"By 2019, we will be the first cruise ship company to use LNG to power our ships when they are both in port and at sea – for their normal operation."

The ports are definitely open to working with us on this process and want to implement LNG fueling there, but there are processes they have to follow. In many cases, you have to go through public consultations, etc.

In terms of Carnival actually using LNG on ships, how can the AIDAprima vessel use it without having any onboard storage?

The ship was designed to use the LNG in port. The majority of our ships today are diesel-electric. We generate our own electricity like a small power station and that electricity is used both to propel the ship, as well as power for our on-board hotels.

So rather than plugging into an electrical supply (which by the way is not available in any of the ports that we call at) we use a clean fuel – LNG – instead to generate our power needs.

In the case of the AIDAprima, the before mentioned trucks park next to the ship and allow for a direct connection so it can draw fuel directly from the tank of the truck alongside the ship. The LNG provides a cleaner solution while docked, which is a favourable option to reduce emissions in the environments we are visiting.

Has Carnival sacrificed passenger space in order to use LNG technology?

There is an impact on available space due to a high volume needed for storage. I won't shy away from that, but we got around it by working with shipyards to optimise the design of the ships to best utilise space – creating multi-use spaces, making better use of wasted space and designing more efficient spaces to ensure that our guests' experience is not impacted by the design.

Typically, LNG requires about 1.8 times more space than conventional fuel, but that is located inside the engine spaces, not in the part of the ship not used for revenue generation.

That's the first point – optimising design can minimise the impact on revenue generation spaces. Typically, the impact would most likely be in machinery spaces, which could otherwise be used for something else, or in areas like crew accommodation, so you would have to shift that to another location, and we worked with the shipyard to design new, next-generation vessels. If you look at the size of the vessels – the new ones are 180,000 gross tonnes and hold around 6,000 passengers. That's why you need large amounts of power.

Is Carnival the only cruise operator making an initial shift to LNG technology? And looking ahead, might emission regulations drive up costs for Carnival and challenge its business model?

We were the first to make that choice, but I think they're all looking at it because it is such an impressive and responsible option. [Geneva-based cruising line] MSC has announced that they are considering using LNG in some of their vessels.

"The ports are definitely open to working with us on this process and want to implement LNG fueling there, but there are processes they have to follow."

We live in a world with ever increasing environmental regulation. People and therefore governments are concerned about the environment. We see this in discussions of global warming and putting a price on CO2 emissions, as well as reducing SOx and NOx emissions.

At the end of the day, there is a cost for compliance for all companies that are regulated and that cost is most-usually passed on to consumers in price of the goods they buy and the fuel they put in their cars. For us, we will look for solutions to ensure that as minimal of a cost as possible is passed down to our customers.

To most people, buying an electric car in the UK without a government subsidy to help drive down the purchase price would be unaffordable. We don't get a subsidy, therefore, we absorb some of that cost and some of it will be passed on to guests in a minimal fashion. Those are the normal economics, but we certainly do everything we can to optimise our operations and supply chain and get the best possible price for fuels.

This interview was first published in LNG Business Review, July 2016.

Ana Stanic
Founder
E&A Law

The investment outlook for Europe's energy sector appears increasingly uncertain, as EU centralisation and fractious geopolitics heighten regulatory risk. Gas Strategies spoke to Ana Stanic, founder of boutique firm E&A Law, to discuss the shifting sands of the EU legislative environment and what it means for energy investors.

What is your view on the investment climate in the European energy sector?

The European investment climate is at its most uncertain point in a decade. You could say that's because of the complex geopolitical situation, but it's also a question of rising regulatory risk in the EU.

There are a number of reasons for this trend: the fact that we are yet again faced with proposals by the European Commission to amend EU energy legislation is a key uncertainty; the fact that some of these proposals suggest a departure from the liberalised, market-based approach to EU energy policy is another.

Furthermore, the investment framework, with its arbitration framework that has existed since the 1960s, is under threat in the EU. The energy industry views arbitration as a key mechanism for settling disputes with states, as it ensures that they will be resolved by a neutral and entirely independent body. But in the case of the Canada-EU Free-Trade Agreement, for example, the EU has removed the right of energy companies to appoint arbitrators in investment disputes brought against any of the states, and replaced it with a mechanism where all arbitrators are appointed by Canada and the EU Commission.

The Commission is also trying to terminate bilateral investment treaties between EU Member States and is challenging (albeit unsuccessfully) the jurisdiction of arbitral tribunals to decide on disputes where EU states are respondents. With respect to investments that are already in place, we've seen the Commission take the unprecedented action of preventing Romania from complying with an arbitral award, which is, under the ICSID Convention – a multilateral treaty to which all EU countries are party and have been for the last 30 years – automatically enforceable.

Although there's no legal basis for Romania to refuse the enforcement of the arbitral award, the Commission has argued that Romania's compliance with it would amount to illegal state aid and has threatened the country with infringement proceedings.

There are some who argue that state aid is a matter of international public policy, but I don't agree. The very fact that state aid approved by the Commission is not illegal means that state aid itself is not a matter of international public policy. In any event, under the ICSID Convention an award contrary to international public policy must be enforced: enforcement is automatic.

The actions of the Commission have set off alarm bells everywhere. We'll see what the EU Court of Justice says since the Commission's actions have been challenged.

I very much hope the court will come down on

the side of investment protection and uphold international treaty obligations.

So, we can see that there's a growing friction between EU and international law. Nord Stream 2 is another example of this friction – in this case, between EU law and the UN Law of the Sea Convention (UNCLOS). And if you put all this in the mix you get a pretty uncertain investment climate.

What does this actually mean for potential investors?

It's unappealing for our own companies, which are already struggling. It's also unappealing to foreign investors, who, the Commission says, we need to attract to Europe to invest in our infrastructure development.

What kind of infrastructure investment is needed?

In my opinion, emphasis should be placed on the construction of interconnectors to ensure the free flow of gas within the EU and thereby the creation of an internal EU market.

At the same time, more emphasis should be given to creating a coherent energy policy in which the role of gas as a transition fuel is clear, and energy security is pursued from the viewpoint of the energy mix as a totality, rather than by reference to each fuel separately.

"In my opinion, emphasis should be placed on the construction of interconnectors to ensure the free flow of gas within the EU and thereby the creation of an internal EU market."

There has been much talk about the "Energy Union". What do you make of it?

The concept of "Energy Union" was coined by Donald Tusk when he was the Polish Prime Minister to promote the idea of a single buyer of gas. Somewhat bizarrely, even though the concept was vehemently attacked as an anti-market idea that breached EU competition law, it was adopted by the Commission and has now become central to its energy strategy.

Although the Commission has sought to distance itself from Tusk's original concept, the Parliament and certain Member States continue to see joint purchasing of gas as a key, albeit unwritten, objective of the Energy Union.

The Commission's proposed amendments to the Decision on Intergovernmental Agreements (IGAs), which envisage it taking an active part in the negotiation of bilateral IGAs with non-EU member states, as well as the amendments to the Security of Supply Regulation, which entail detailed information on commercial contracts being provided to the Commission (and which is already being provided to ACER) point in the same direction.

Why this remains an objective given the gas glut in the EU and falling gas prices is unclear to me. The pursuance of this objective, despite it being contrary to fundamental principles of EU law, in my view further undermines legal certainty in the EU.

Moreover, when it comes to security of supply, having access to this kind of information does not provide any assistance or guarantee. Security of supply is about physical availability, not contractual availability.

The Energy Union is not a legal concept; it is a political strategy. Consequently, an IGA cannot be said to be incompatible with EU law simply because it is incompatible with the objectives of the Energy Union. Nor can an infrastructure project be approved or rejected by reference to its compliance with the objectives of the Energy Union.

It is crucially important that decisions issued by national regulatory authorities and the European Commission are based on EU law and soundly reasoned. Depoliticisation of EU energy policy is crucial to reducing uncertainty surrounding energy projects in the EU.

What is the motivation for the EU's behaviour?

Centralisation of power in the hands of the

Commission is, in my view, the most likely motivation. The Lisbon Treaty marked a turning point because for the first time, in Article 194, EU institutions gained the competence to adopt legislation with respect to energy. The EU and Member States now share competence in the field of energy.

In respect of EU foreign energy policy, the Commission has asserted that the EU has exclusive competence on account of it being afforded the same in respect of foreign direct investment, including in the field of energy.

There have been repeated calls for the "Europeanisation" of energy policy. It is said that Member States don't sing from the same hymn sheet when it comes to energy policy – for example that Germany is too pro-Russian, that the UK does whatever it wants and so on. I agree there's a need to Europeanise energy policy, but not with moves that undermine the market liberalisation model and hamper the investment climate. The latter are, in my view, fundamental to successful energy policy in the EU.

"I agree there's a need to Europeanise energy policy, but not with moves that undermine the market liberalisation model and hamper investment."

When Donald Tusk called for the adoption of the concept of the Energy Union, arguing that what the EU needed was a cartel of buyers to be on the other side to Gazprom – because that was the only way to secure favourable market prices – that, in my view, amounted to a departure from the market liberalisation model. As do some of the proposed amendments to the Security of Supply Regulation.

I don't think there is any legal basis, nor any need, for such a departure. The current glut of gas in the EU market and arrival of US LNG shows the market has and can deliver lower prices.

We must not forget that all EU gas supply contracts contain price-review clauses and that arbitration has been used successfully to lower prices. All of this is evidence that the market is working – so the last thing we need now is legislation that undermines market principles.

I think EU legislation should be concentrated on delivering an internal market for energy rather than energy security – the latter follows the former.

So where does Nord Stream 2 fit into all this?

Under international law, an EU Member State cannot stop a pipeline from being constructed in its exclusive economic zone ("EEZ"), but it does have a say over its route. A distinction is drawn between sovereignty, which a state has over its land and territorial seas, and the sovereign rights it enjoys to exploit natural resources in the EEZ pursuant to Articles 58 and 79 of UNCLOS.

When NS1 was being built, EU institutions accepted that the Third Energy Package (TEP) did not apply.

In recent discussions it has been simply said that the TEP applies to NS2. However, the only way this argument can succeed is if somehow it could be argued that EU law trumps international law. It wouldn't be the first time that EU lawyers have taken this view, and the Commission does like this view – it certainly took that view when it forbade Romania to comply with the ICSID arbitral award, which we discussed earlier.

But I don't think it is legally sound. Nor do I think that ignoring international law is a policy the EU should pursue, especially given the state of the world today. I think the EU should promote compliance with international law by showing that it will itself abide by the rules.

This interview was first published in LNG Business Review, August 2016.

Spencer Dale
Group chief economist
BP

The global energy mix may be experiencing dramatic change, but the outlook for demand growth remains as strong as ever. Gas Strategies spoke to Spencer Dale, chief economist at BP, to discuss the company's projections for global gas demand and the risks and opportunities for IOCs in a carbon-constrained world.

BP has cut its upstream CAPEX in response to the fall in oil and gas prices and is working to a price of USD 50/barrel for planning and evaluation purposes. What probability do you see for an overshoot in prices, say over USD 80/barrel, even if only for a limited period?

There are three key factors that will have an impact on the pattern of oil prices over the next few years as the market continues to rebalance. Even as the oil market moves into structural balance over the remainder of 2016, we'll be left with an enormous stock overhang. This will act as a natural dampener on the pace of price rises, because if prices recover quickly people will take the opportunity to liquidise those stocks.

Secondly, as prices start to rise we are likely to see US tight oil activity increase. We've seen the rig count rise pretty steadily over the last couple of months and the question is just how quickly and by how much US tight oil will come on.

The third factor is the very significant cutback in CAPEX. Many people say that ups and downs in the oil market are normal and I accept that they are, but the reductions we've seen in CAPEX are unusually large. You have to go back to the late 1970s to see such a large [proportionate] fall. By the end of this year, we could see nominal oil and gas CAPEX spending around a third lower than in 2014. That's a big reduction. Some of the impact of that fall in nominal spending has been offset by cost reductions, but only some of it. That will cause oil supplies to grow less quickly than they otherwise might have done.

The impact from the CAPEX reductions is likely to build over time – we don't see those effects very much at the moment, but when we get to 2018-2021, the market is likely to have tightened. The net effect of those three factors is very hard to predict.

How do you project global gas demand developing beyond 2035?

BP's Energy Outlook goes out to 2035 and we haven't done any formal modelling beyond that period. There will be two or three key drivers of gas demand beyond that period.

First, it will depend on what level of demand growth continues to come out of emerging Asia as productivity, economic growth and prosperity increase. In the period beyond 2035, demand growth in Africa will also be a huge determinant. You would expect to see Africa emerging as an increasingly important growth centre for global energy demand.

A second issue is what role gas will play in the power sector, and although my crystal ball doesn't go out that far, my guess is that gas

will play an increasingly complementary role, supporting renewables. As renewables grow they will increasingly provide baseload in the power sector in many parts of the world. But until we find an economically viable solution for large-scale storage of energy, I expect gas to be a natural complement, acting as the fuel that balances the system and solving the intermittency problem.

But exactly what role gas will play will depend on just how quickly renewable energy develops over the next 20 years, and on the nature of advances in storage technology.

How fast do you expect alternative energy sources to achieve penetration?

I expect renewable energy, particularly wind and solar power, to grow very strongly over the next 20 years. Moreover, if I compare renewables over that period to the growth of other fuels at a similar stage of their development, I expect renewables to grow more quickly than any [energy source] in history. That's built into our outlook.

But the lesson from history is that it takes many decades for new energy to penetrate the system. So while I expect renewables, fuelled by technology gains and increasing economies of scale, to do better than anything that's come before, it's still likely to provide only around 10% of the world's energy by 2035.

There's plenty of room there for gas to play an important role. There will be some displacement of other fuels, but I expect the burden of that to fall on coal. Whereas gas, partly because of the complementary role it can play with renewable energy, and partly because of increasingly strong supply (such as US shale gas) and increasing mobility of gas via LNG, can play a significant role over this period.

"If we burnt all the fossil fuels reserves that we know exist and can be extracted using today's technology, it would produce around three times as much carbon emissions as scientists believe would be consistent with a sustainable 2 degree world."

How can IOCs best manage climate risk and minimise the risk of stranded assets, or a carbon bubble-type crash?

The language of "carbon bubbles" and "stranded assets" has a lot of confusion and uncertainty. Different people mean different things by these phrases.

If we burnt all the fossil fuels reserves that we know exist and can be extracted using today's technology, it would produce around three times as much carbon emissions as scientists believe would be consistent with a sustainable 2 degree world. So I do not expect all of these assets to be extracted.

But, looking at the balance sheets of the five major IOCs and the proven reserves that give them value, they count for something like less than 3% of the total reserves I just referred to. By proved reserves, I mean the Securities and Exchange Commission (SEC) definition, which is those reserves where there are clear plans to extract the resource and where it is economically viable to do so in a relatively short period of time. Less than 3%, and these are likely to be extracted in the next 10-12 years.

So do I think that any of the assets currently giving value to the IOCs are likely to be stranded? No I don't, and frankly I think you'd be hard pressed to find anybody that really does think that.

Has the window for useful economic development of carbon capture and storage (CCS) passed?

No, I don't think the window has passed. There is still considerable uncertainty about the pace at which we will transition to a low-carbon world and the optimal pathway, but almost all the pathways I have studied show a significant role for CCS. Exactly how significant varies, but CCS typically

plays an important role in enabling a transition to a lower-carbon world.

It seems to me that if one could find a way in which CCS could be increased significantly it would have huge benefits for mankind, because it would allow us to keep using natural gas, which we know is incredibly well suited to providing societies' needs for heat, light and mobility.

If governments and industry were able to find a way of achieving material expansion of CCS it would have potentially huge benefits. It's about trying to find the right government incentives or support to achieve CCS. BP have been very clear that we think carbon pricing is the most efficient way of trying to think about these incentives.

But carbon pricing has not worked that well for gas in Europe. What kind of changes in design would you like to see to benefit gas?

Carbon pricing can provide the right incentives to create a switch away from coal and into gas. And that switch brings huge benefits in terms of carbon emissions. Something like a 1% switch from the share of coal to gas in the power sector would have the same carbon-reduction benefits as a 10% growth in renewables.

"I expect renewable energy, particularly wind and solar power, to grow very strongly over the next 20 years."

We also know that the share between coal and gas is very price sensitive. We saw a massive switch between the share of coal and gas in the US last year as the price of gas fell relative to coal.

Closer to home, in the UK the introduction of the new carbon price floor led to a very significant shift away from coal and into gas, and as a result, a reduction in carbon emissions. One can think up lots of clever policy designs, but the increase in the floor price has resulted in a very significant shift in the fuel mix.

I don't think this is rocket science, I think it is a question of political will – and economics. And in the market environment I think we are likely to see over the next five years or so, with abundant global supplies of natural gas, if Europe were to think about introducing a carbon price floor similar to what we've seen in the UK, that could have very significant impacts in terms of encouraging greater coal-to-gas switching and reductions in carbon emissions.

This interview was first published in Gas Matters, September 2016.

Laszlo Varro
Chief economist
International Energy Agency

As renewable investment costs decline, it appears only a matter of time before the cost of installing new wind and solar capacity becomes competitive with fossil fuels without subsidies – achieving so-called "grid parity". But does this mean there will be less scope for gas-fired power in the future? Gas Matters spoke to Laszlo Varro, chief economist at the International Energy Agency (IEA), about grid parity, renewable growth and the outlook for gas markets.

Are global investment costs for new renewable generation really close to "grid parity" level? What is the key driver for falling costs?

I don't like to use the term "grid parity" as it's a very complex concept, often used in an oversimplified and misleading fashion. Costs should really be viewed region by region.

The competitiveness of renewables critically depends on the characteristics of the given electricity system – what is the renewables' production time profile; are we talking about an electricity system with growing demand, or is renewable generation installed to satisfy a policy objective?

Wind and solar cost declines are driven by different factors. The cost of solar panels has declined due to an increase in mass manufacturing in China. Investment costs for wind have not fallen nearly as much as for solar, but wind turbines are now able to produce more power due to higher average load factors.

The industry has been producing turbines that capture strong winds for more than ten years, but thanks to technological progress over the last five years, turbines are now also able to produce effectively from medium-strength winds. Consequently, the investment cost of a new turbine is only a bit lower, but it produces 25% more power annually because it can capture weaker winds.

The production profile for wind has changed as you can produce more power in a year, but solar profile is largely unchanged and heavily concentrates in the summer midday hours. Both technologies also benefit from quantitative easing in the US and Europe, which have led to ultra-low interest rates and lower costs of borrowing.

How does the cost of capital for renewable energy investment currently compare with fossil fuels?

There is a very clear asymmetry for the cost of capital investment. The most successful renewable policies are increasingly based on long-term contract auctions – in Peru, Mexico, Morocco, India and many other places. If you win the contract, you sign a long-term agreement with either the government or a government-mandated entity.

There is also a climate finance component, which means the World Bank or an export credit agency or another development bank will provide

sovereign risk insurance, currency hedging and other financial services. As a combination of this, renewable developers have a high level of leverage and ultra-low cost of capital, much lower than what is typically assumed under the expected rate of return in the oil and gas sector. This also makes matters more difficult.

For countries that rely on long-distance gas imports and need more power for their consumers, such as Japan, China, India or Brazil, the average investment into the LNG value chain is twice as high as the required investment for power generation. If you want to build a CCGT supplied by LNG, then building the LNG value chain will cost twice as much as the power plant.

That matters, because LNG investment is typically carried out by large oil and gas companies that expect 10-15% internal rate of return (IRR), which is applied to two thirds of the investment – the LNG value chain. Compare this cost of capital with a solar farm in India that benefits from ultra-low cost of capital due to long-term contracts, very low global interest rates and the policy support and you will find that the competition is very unequal.

"In the foreseeable future, batteries will become good enough to take sunshine at noon and use it at 8 pm in the evening."

Can gas compete if you compare gas-to-power investment with renewables on a levelised cost of electricity (LCOE) basis?

Combining effective policies with attractive natural resources, like Peruvian sunshine or the wind off the Atlantic coast of Brazil, and recent technological progress will result in extremely low renewables LCOE. Technologies with different cost profiles will struggle to compete.

However, LCOE does not take into account the time profiles of renewables and the value of power to the system. For example, Japan and Germany – two countries with large installed solar parks – have very different power demand profiles. Peak demand in Japan is 2 pm in July, as air conditioning boosts power consumption and solar is extremely valuable. By contrast, peak demand in Germany is at 7 pm on December evening, when there is no solar production. There is no guarantee that the lowest LCOE technology has the highest value for the system.

This principle could also be applied to gas. Typically, gas-fired generation LCOE methodology assumes that the plant operates at a baseload annually, but in modern power systems with huge installed renewable capacity, gas rarely operates at baseload. Gas is mainly confined to following the residual load – it will run only when wind and solar are not available.

Gas plant utilisation will be low and volatile, but the hours that gas-fired generation is operating are more valuable. The attractive LCOE of wind and solar does not mean there is no role for gas. You still need flexible capacity in your system.

What role will batteries play in the future?

Some of the balancing flexibility will come from electricity storage in the future, which is already improving. Some will come from demand-side response, regulating consumption flexibility and interacting with a smart grid.

In the foreseeable future, batteries will also become good enough to take sunshine at noon and use it at 8 pm in the evening. There is certainly scope for that, but I cannot conceive of battery technology that could help Brazil deal with a six-month drought.

If your objective is to electrify a poor village in Southern Sudan, don't build a gas-fired plant. Give them solar power, give them batteries, LED lights or even a mobile phone charger, and you take a huge step forward. But gigantic cities such as Lagos, Nairobi, Karachi, Jakarta, which in 20 years will be twice the size of New York, cannot rely on battery storage.

These cities might have a lot of sunshine, but they still need a centralised electricity network, to serve demand whose density might be higher than what can be supplied with decentralised generation. Peak demand in these countries is often after sunset, when it is very humid and air conditioning is running flat out. There is also

heavy industrial demand concentrated in major cities, which would be difficult to supply with solar and batteries alone.

Additionally, tropical countries are often affected by monsoons, which brings seasonality to wind output – you can have strong wind during one part of the year, and no wind in the other. With such time profiles, batteries would struggle to compensate for substantial periods of renewable production shortfalls, leaving room for gas.

Does the IEA see power sector demand playing a key role in rebalancing the LNG market?

In 2012-2014, when LNG was expensive, gas-fired power generation in India dropped to a very low level. India had more than enough CCGTs, but they weren't running because LNG was expensive.

India recently renegotiated its import contracts with Qatar, achieving a major price discount, and now its LNG imports and power plant utilisation are rapidly increasing. India is a good example of how market rebalancing has already started.

In many Asian countries coal is the default option for power, and during the time of expensive LNG coal dominated power generation investment in Asia. Investment in coal in Asia remains strong, but gas has a chance to get back into the competition in countries that already have gas infrastructure. There is still significant demand potential in Asia, but for most of that you would need to build more infrastructure.

But there are other important factors outside the electricity sector that provide growth for gas, and should help rebalance the LNG market.

In China, local air quality policy will drive consumption. Gas demand in Beijing has doubled over the last four years as a result of strong policy by the city government, which is decommissioning small, inefficient coal-fired boilers.

"Regionally, Europe will play a key role in rebalancing the LNG market, because European gas production decline is significant and irreversible."

Several other Asian countries have policies mandating the use of natural gas as a heavy-duty transport fuel and, as a result, there has already been a significant rise in CNG-fuelled buses and LNG trucks.

Regionally, Europe will play a key role in rebalancing the LNG market, because European gas production decline is significant and irreversible. Even with stagnating demand, Europe will import more gas and some of it will come from Russia, but a lot of that will be LNG. Russian gas could become more competitive if LNG prices increase, but Russian flows to Europe are already at a very high level.

Europe has massively underutilised LNG infrastructure and effective functioning gas markets. If you want to sell LNG into Vietnam you need to negotiate with the Vietnamese state-owned utility, which can take time as you need various approvals. But on the European market you only have to book capacity in Rotterdam and drop the LNG on the spot market. European spot prices might not be very high, but the market is reliable and transparent.

This interview was first published in Gas Matters, October 2016.

Dr Ludwig Moehring
Managing director, sales
WINGAS

Germany's 'Energiewende', the anti-nuclear inspired transition to cleaner energy, is remodelling the country's energy mix in favour of renewable power generation and enhanced-energy efficiency measures. Laudable as it may be given global climate accords, this political movement has become better known for its inherent contradictions – coal is now the biggest fuel source alongside renewables in Germany's mix, negatively offsetting the latter's benefits, while cleaner fuels, principally gas, are pushed down the merit order. Gas Matters spoke to Dr Ludwig Moehring, managing director, sales at gas supplier WINGAS, to discuss the paradoxes and unanswered questions surrounding the Energiewende.

How effective has the Energiewende been? How close is Germany to achieving its energy goals and what does it mean for renewables and gas?

If you examine it exclusively from a CO2 perspective then the numbers tell the story – we were emitting around 900 mt/year of CO2 equivalent back in 2010, and this is still broadly where we are today. So the long and short of it is that we have achieved very little.

At the same time, renewable power generation now accounts for above 30% of Germany's total power demand. So that is good news in terms of growing renewable power generation – but has it really helped us to do something for climate protection? Has it really helped us achieve Germany's CO2 reduction targets, which are to reduce CO2 by 40% compared to 1990?

The truth is, Germany will not achieve this because we've just focused on building more renewables – we've not focused on how to achieve the necessary CO2 reduction. And in parallel with growing renewable power generation, coal-fired power still accounts for more than 40% of Germany's power generation, which is at the same level as 2010, while gas is down by a third. Not surprisingly this has kept CO2 emissions high.

But let me talk about the challenges ahead and focus on a few examples where life becomes really difficult and expensive:

1. In the context of the Paris Agreement (COP 21) and the Marrakech (COP 22) outcome, the story from Germany is that the world should not follow its example because we have not been able to reduce CO2 output broadly – and the CO2 clock is ticking. If the world keeps emitting CO2 at current levels the CO2 budget for the century will be exhausted within the next 20 years (if we really want to meet the 2 degree target). There are other countries that have been able to make progress on the CO2 reduction path, and largely by replacing coal with gas – for instance the US and increasingly the UK, who are much more

pragmatic and results orientated when it comes to climate change.

2. Security of electricity supply is another challenge. As long as power cannot be adequately stored, intermittent renewables need some backup to ensure security of supply at any time, which is necessary for power demand. Hence, we cannot just say that if we build 100 GW more renewables we can shut down 100 GW of thermal power generation. That is not going to work from a security-of-supply perspective. We will need additional (conventional) power plants, unless we are able to find some way to store the electricity, which is not yet possible on a large scale.

Of course, part of this we may be able to manage through increased energy efficiency and smart homes. But the fundamental question – "how do we ensure security of electricity supply in a world of intermittent power generation?"– won't go away.

3. Let's take a look at the recently agreed German Climate Action Plan 2050, which is supposed to pave the way for the next 30+ years. This plan already establishes the approach that, by 2050, all areas of energy consumption will rely on electricity. This "all-electric world" is based on the assumption that massively growing renewable energy will replace other sources of energy. Technical feasibility, security of supply and related cost for consumers remain undiscussed.

Already there is reference to a plan to ensure that renewable energy is more commercially attractive than the alternative conventional fuels. In my interpretation, this means that politicians plan to find ways to make it less attractive for consumers to use gas. Winners are being picked through state intervention. Let's see what the consumers, who also form the electorate, say when such an approach is challenged as suboptimal.

To be clear: the gas industry fully supports climate-protection goals, but we want to have serious measures that are affordable and have a positive climate result. That's not what we see today – we see a bold vision for an ideological all-electric world, but no clear plan for implementation.

Where did German policy go wrong?

When it came to climate, it went wrong almost immediately. Of course, there were all the right intentions: getting out of nuclear and growth of renewable energy – all of this was and is backed by the German people. However, the programme should have been: "We have a plan to reduce CO2 by 40% until 2020", which was actually set as a target at the very beginning. CO2 reduction went very quickly out of focus though, and looking at the current plan of action it still is out of political focus, even after COP 21.

"We now have the paradox that modern, state-of-the-art German gas-fired power plants are being mothballed, while we pay millions to run 30-year-old Austrian oil-fired plants as backup."

Renewables are not an end in themselves. Relying on more than 40% coal-fired power generation (at the expense of gas!) while growing renewable energy is not a coherent climate-orientated energy policy. This is aggravated by the fact that, even with the COP 21 and COP 22 agreements, coal-fired power generation is supposed to stay put for the next 30 years – which is also confirmed in the German Climate Protection Action Plan 2050.

In Germany, we now have the paradox that modern, state-of-the-art German gas-fired power plants are being mothballed, while we pay millions to run 30-year-old Austrian oil-fired plants as backup for system stability in southern Germany.

Currently, German gas-fired plants do not even earn their short-term marginal cost most of the time. At that stage, and unsurprisingly given that things look unlikely to change, companies decide to mothball or dismantle.

Coal is cheaper and will be used first – this is the result of the so-called 'merit order' effect. It remains to be seen whether serious efforts to reduce CO2 in the power generation sector will lead to an exit consensus on coal.

So what is the story for gas?

The facts are pretty straightforward, but the issue is that our business has become very politicised, so we have a major job convincing the relevant stakeholders. The case for gas is centered around one hard fact: the energy world needs conventional fuel next to renewable energy, and then it's all about finding the right relationship between the two. This is how you should approach climate protection – what is the most cost-efficient and climate-effective way to combine conventional fuels and renewables?

As a result of its environmental advantages, gas is in a very strong position for such development. The International Energy Agency, for example, expects in its new World Energy Outlook 2016 a worldwide growth of gas by 50% between now and 2040, exactly for that reason.

"Renewables are not an end in themselves. Relying on more than 40% coal-fired power generation (at the expense of gas!) while growing renewable energy is not a coherent climate-orientated energy policy."

Unfortunately, in Germany energy policy appears to be based on a very simple, or rather simplistic, assumption: "fossil fuels are bad, renewables are good".

Why is that the case? Because it has become very ideological. There is an anti-fossil fuel mentality. Of course, we should appreciate scepticism towards fossil fuels in a world of CO2 mitigation, but we have to find a way to reach the endgame of the low-carbon world. We have to survive transition – we need a transition that is affordable, remains supported by the electorate, and yields the results we want. Demonising fossil fuels does not achieve that.

We have to get it across to policymakers and other relevant stakeholders that modern sustainable energy policy ensures real climate protection through the optimised integration of renewable and conventional fuels. And that's why we should not be hesitant to promote our story. As a gas industry we have to be outspoken. We have all the right arguments around climate protection and other related issues. That's also why I'm so adamant about this line of argument – we could do much more, and we have to.

What should be done about the EU Emissions Trading System (ETS)? How can carbon trading become effective?

The ETS is an excellent tool. It prices CO2 and it should also be used to make sure we have the volume of CO2 emissions we want to have. Unfortunately, it's completely ineffective at this stage.

The current CO2 regime has two areas for improvement: (1) is the connection of CO2-reduction targets derived from the Paris agreement with ETS certificates, (2) is widening the scope, which currently only covers part of the CO2 emissions areas, while others, e.g. private heating or mobility, are not affected.

With the amount of CO2 tonnage currently accepted at the European level, we are now at prices that do not have any effect on CO2 reduction whatsoever, and – in the case of Germany – we will not reach CO2 reduction levels for 2020 that were committed to. But let's be realistic: within the EU we will struggle to find a compromise on the ETS among all the EU member states at any point in the near future, if such compromise results in a major reduction of near-term coal-fired power generation.

Carbon pricing is a tool to establish a refereeing mechanism among the conventional fuels in order to cap CO2, and we need it. We have to work on all levels and there are good arguments to start this now. Waiting ten years may be too late – both for the climate and for companies that may have left the European scene in the meantime. In the best interests of effective climate protection this is an unwanted scenario.

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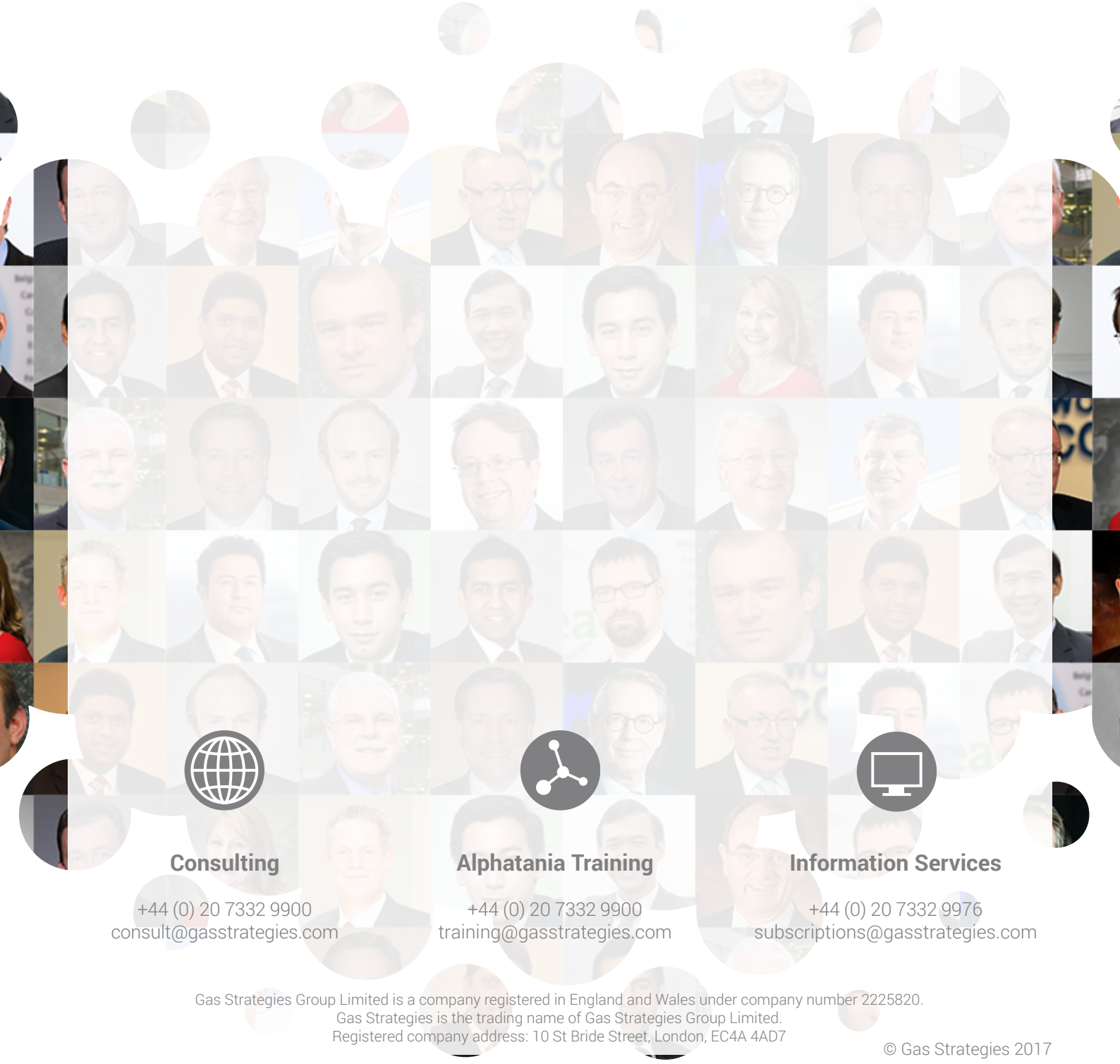
Gas Strategies



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