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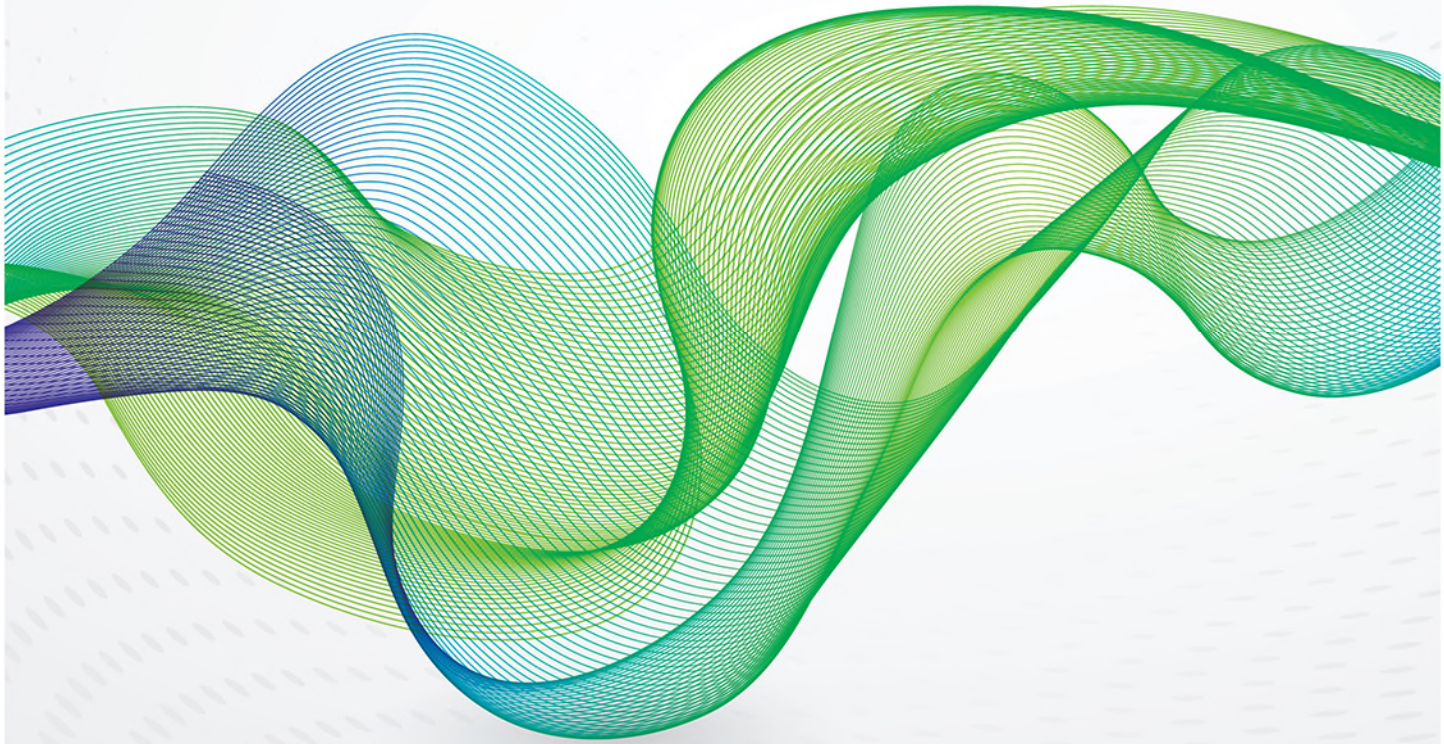

Brainstorming XXVII – with kind support from the Argus Media & SPOL

Edinburgh

The Oxford Institute for Energy Studies held its Twenty-Seventh Brainstorming Meeting in Edinburgh on the 26th and 27th May 2016, with kind support from Argus Media and SPOL.

The OIES Brainstorming is an annual forum of invited participants to review developments in international energy markets. Proceedings are conducted under the Chatham House Rule.

The Meeting comprised the following sessions:

- The world economy.
- Geopolitics of energy.
- The oil market.
- The products market.
- The oil industry.
- Changes in regulatory landscape and benchmarks.
- Gas, LNG markets, and pricing mechanisms.
- COP 21 and its implications.

The contents reflect views expressed by participants at the Meeting and do not necessarily represent the views of OIES. The contents should not be construed as a forecast of any kind.

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Session I – The world economy

Review of the world economy

Although it has been seven years since the global financial crisis, the world's economy is still struggling to regain momentum; world growth in 2016 is thus not likely to be different from that seen in 2015. In advanced economies, growth continues to falter, and in emerging and developing economies, there is considerable divergence of performance.

In the USA, strong labor income continues to support consumer demand and residential investment. But softer than expected activity since the start of this year has led to downward revisions of growth projections. There has also been a shift in sentiment about US growth prospects. Despite above-trend gains in real disposable income (on the back of robust job creation, relatively low unemployment, low interest rates, and low inflation), there is widespread pessimism within the country, with some analysts even predicting a US recession next year. Part of this concern is related to perceptions about economic growth. The USA has experienced around 2 per cent growth on average in every year since 2010 and this is likely to persist in 2016/17; while this is positive compared with Europe and Japan, it does not match the USA's past performance. US citizens feel that manufacturing has moved abroad, mostly to China, and that globalization has mostly benefited the elite, while median wages have remained low. These perceptions are reflected in the two political extremes of candidates in the US presidential election campaign (Trump and Sanders). Although nothing in the numbers suggests that economic performance would be radically different or that there would be a recession, the political landscape is uncertain and gives rise to doubts over its impact on other parts of the world.

A similar story can be seen in Europe, where the recovery in the euro area has been proceeding but at a moderate pace. Low oil prices, accommodative monetary policy, and a slightly expansionary fiscal policy have aided a modest recovery. Growth in 2016/17 could be around 1 per cent against the backdrop of volatile politics. The political risks remain higher in the EU than the USA, due to persistent tensions in the eurozone with 'Brexit' adding to these risks.

With regard to the rest of the world, the rapid growth seen in China over the last 20 years is unlikely to return; however, this also highlights the fact that the country's narrow focus on GDP has been restrictive from the start. Industrial production in China grew at 15–20 per cent per annum during the 'economic boom' and this is likely to drop to 4–5 per cent, but some of this slowdown will be offset by growth in the service sector. Pressures from commodity prices are an issue for emerging market economies. Sharp adjustments to lower oil prices are weighing down on the growth prospects of oil exporting countries. In the past few years, Russia and Latin America have been major beneficiaries of high commodity prices, but this is unlikely to recur in the next decade. And while India's economic performance has been strong, it is not sufficiently large at present to offset slower Chinese growth.

Although global growth prospects remain very much unchanged from last year, the downside risks have become more pronounced. These include: deteriorating conditions among key commodity exporters, slow activity in the USA, and heightened policy and geopolitical uncertainties. Over the medium term, there is the risk of increased protectionism and of increased political extremism. The lack of growth in international trade is also worrying, as recession typically tends to strike following two to three years of trade stagnation.

China's rebalancing

China's 'new normal' is likely to be reflected in a growth rate of 6.5 per cent over the next five years, as the economy slows and shifts from heavy industry/export-oriented growth to consumption. The focus is also on greater industrial competitiveness, the environment, and innovation – as demonstrated by the fact that China's Thirteenth Five Year Plan has a chapter on environment, but no chapter on energy. A paradigm change has been seen in the ascent of Xi Jinping and the political scrutiny of corruption within the party. Questions over political legitimacy have taken a toll on

economic growth, breeding an aversion to risk. Decision-making structures are centralized and bottlenecks have resulted from a lack of direction. The stock market crash and currency reforms are indicative of a broader thrust towards liberalization. However, sentiment worsened and decision makers responded with 'old fashioned' strategies – stimulus, fixed asset investments, and the injection of credit into the system. However, Xi Jinping eventually announced that debt-driven recovery was unsustainable and that China would have to move to an economic path that was likely to be 'lower for longer'. This was followed by a refocusing on supply-side reform, curbing overcapacity in industries such as steel and cement, and the tightening of regulation by provincial governments.

These responses could be indicative of greater cyclical changes in years to come, with the government moving from policies trying to sustain growth in the short term, and then pulling back on the basis that they are detrimental to medium/longer-term plans. Despite these cyclical swings, it is likely that the administration will come up with a way to 'reach the numbers' through 'cooking the books' or carrying out stimuluses. These swings may be reflected in international markets, which could alternate between periods of 'alarm' at falling Chinese demand, followed by 'relaxed' periods when credit growth comes in. Therefore, although China is likely to achieve its growth numbers, the trajectory will be volatile. This also has implications for Asia; north-east Asia is extremely exposed to China's downturn and also to the potential for greater competitiveness from Chinese industry. Nevertheless, other parts of south-east Asia will grow, on the back of big infrastructure investments. China's rebalancing is likely to be slower than expected, with regional variations as opposed to headline figures. North-east China, for instance, is suffering from severe recession (as heavy industry slows down), whereas central China is adapting better to the rise of services and consumption. China's growth is therefore also likely to be two-track.

India to the rescue?

India's economic growth surpassed that of China in 2015 (7.5 per cent) and is projected by various multilateral agencies to remain relatively high in 2016 (7.4–7.5 per cent) and 2017 (7.8 per cent) (although the rebasing of national accounts statistics in 2015 is partly responsible for the upward revision of these figures.) Some of this growth has come on the back of the halving of oil prices and of subsequent related policy responses. Diesel subsidies were eliminated in October 2015, and price differentiation was adopted for LPG, making kerosene the only fully subsidized petroleum product. The government has replaced universal subsidies with direct transfers using a social security number system which, it claims, has been issued to 900 million citizens. The petroleum subsidy bill was consequently 70 per cent lower in 2015 than in 2014. However, the full reduction in crude prices was not passed on to consumers in 2015 as the government chose to increase excise duties (set at zero during the $100/barrel era) which led to revenues of around $24 billion. India's NOCs (which had previously used their revenues to finance subsidies) also benefitted from reforms, reducing their 'under-recoveries' (losses from the under-pricing of products) by $17 billion in 2015. The current account deficit for 2015 fell to 1.6 per cent of GDP (compared with 6 per cent during $100/barrel oil). Despite two years of drought, low oil prices have cushioned against inflation.

Conversely, India's exports, 35 per cent of which are commodity-linked, have fallen for 15 straight months and were 18 per cent lower in 2015 than in 2014. This has also been due to weak demand. While the revenues of the federal exchequer have improved with low oil prices, revenues of states have not, as they obtain much of their revenues from VAT on the sale of petroleum products, which has reduced.

Some of India's growth has been structural. The country embarked upon a massive programme of infrastructure building, aiming to construct 30 km of roads a day in 2016. Around $30 billion has been reportedly earmarked for investments in national highways. This has pushed up oil consumption to record levels (oil demand growth in 2015 averaged 0.30 mb/d as opposed to 0.10–0.15 mb/d over the decade 2003–13). The 'Make in India' initiative, aimed at increasing India's share of manufacturing in GDP from 15 per cent to 25 per cent by 2022 has galvanized FDI, which was 66 per cent higher in 2015 than in 2014. India's 'ease of doing business' ranking also went up to 130 in 2015, from 134 in

2014. India is also less vulnerable to China's slowdown, as the latter represents a small proportion of its total merchandise trade. However, if India's exports continue to decline and its imports continue to rise, the country will not benefit from any devaluation in China's currency (in terms of greater dollar revenues).

Much of India's improved economic performance has come on the back of low oil prices, and its structural reforms have not been sufficiently deep. Wholesale price inflation rose in April after 17 months of decline, reflecting rising oil prices. India's public sector banking system has a huge amount of non-performing assets, much of which is concentrated in the power sector; this is crucial to India's energy plans for modernizing its grid and expanding the share of renewables. A debt restructuring programme was launched in late 2015 to address this, but it will require political consensus at the state level. India's government has tried, and failed, to bring in a streamlined Goods and Services Tax to simplify taxation. The government has made major commitments in its election manifesto ('24 x 7 electricity for all' by 2019) which will be scrutinized in the run up to the 2019 elections.

Discussion

The discussion opened with two questions:

> Given the use of loose monetary policy around the world, why are we not seeing a more visible impact on demand and growth?
>
> Why have the expected positive effects of falling oil prices on global activity not materialized so far?

In response to the latter question, some noted that a few economies, such as India, benefited massively from the low oil price. However, in other countries, such as the USA, the massive cuts in investment (particularly in the energy industry) have offset some of the benefits from cheaper gasoline prices at the pump. In the view of others, there was an assumption that oil-exporting countries would maintain their spending aided by the fiscal buffers they have built over the boom years. However, fiscal adjustments – such as subsidy reform, expenditure reductions, and taxation reform – are taking place in oil-exporting countries, even in those with strong fiscal buffers, such as countries in the GCC. Some have argued that low oil prices in a deflationary world may not have beneficial effects, as low oil prices will reinforce the deflationary trend, increasing the real cost of borrowing. Another view was that the windfall from low oil prices had gone into reducing debt rather than towards spending and thus into triggering multiples in the economy. In short, low oil prices have had a positive impact on growth but there have been some offsetting factors; the global economy would have witnessed a sharper slowdown if energy prices had not fallen, and there could still be a delayed boost to private consumption.

There is also China's structural slowdown. 'Mini stimuluses' in China are relevant in the short term but the structural slowdown in industry will be difficult to counter. China's slowdown is likely to be similar to that of Japan in the longer term but with one big difference: while investors were happy to keep their money in Japan, this may not be the case in China. Consequently, financial deregulation may not take place because of the risk of capital outflows. Therefore, capital controls are likely to be a concern in the medium term.

A question was raised as to whether China's refocus on innovation and the environment conflicted with its priorities on economic growth. In response, it was stated that although the environmental agenda was strong, it did not necessarily conflict with growth. For instance, China is investing in infrastructure to increase the share of electric vehicles. The Ministry of Environmental Protection has been granted the authority to send in teams to enforce environmental rules and overrule provincial authorities in inspections. No other government entity has this power, apart from the anti-corruption agencies. Although China is still building coal power stations (albeit with enhanced efficiency) these are likely to run at 50 per cent utilization. There is a clear business case for environmentally sustainable growth.

The discussion turned to US interest rates. It was pointed out that hawkish statements by the US Federal Reserve have resulted in materially higher asset prices, and rates may have to increase faster as every rate hike results in a rebound in asset prices. A counter view was that the argument for higher interest rates being good for markets was ambiguous. The Fed does not believe the 'secular stagnation' story, which is why it is continuing with the view that it can raise interest rates. Many in the market, on the other hand, believe the secular stagnation story, and thus would like to have low interest rates for a considerable period of time. If interest rates are hiked more than expected, this could lead to volatility. Another view was that low interest rates were keeping zombie companies alive; in a relatively high (or moderate) interest rate environment, there would be a clean-up of these companies, which may be beneficial for economic growth in the longer term.

A question was raised around the theme of the USA being an 'unhappy place' in terms of sentiment. Could this generate a feedback, challenging the 2 per cent growth outlook? It was noted that, globally, substantial proportions of the middle classes are angry with the ruling elite, as the benefits of globalization have not filtered through and remain concentrated in the hands of the few; this is seen not only in the USA and Europe, but also outside the advanced economies, in Brazil and China. The failure to address this issue will lead to political extremism, with some radical non-mainstream political parties gaining power and thus inducing huge policy uncertainty.

Europe contains the largest mass of middle-class spenders. One view was that if 'Brexit' takes place, it would have massive knock-on effects on the euro and on confidence. In the UK, there would be significant short- and long-term negative impacts (for instance, on car manufacturing, FDI flows, and exports to Europe). Widespread anger with the elites has meant that despite the economic case to remain being virtually overwhelming, the UK could still vote to leave. The consequences of Brexit for the UK's future in Europe would almost certainly be negative because: firstly, Europe will not treat the UK 'better' or 'well' afterwards due to the threat of other countries leaving, and secondly, Europe could choose to 'make an example' of the UK to discourage other member states from holding referendums. Therefore, while the economic arguments favour remaining, the political arguments are emotional, reflecting a diversity of opinions. Many see the heavy handed regulation of Brussels as negative, and would want to see a weaker central EU government. There has been growth, but a lot of this has been dissipated through excessive regulation. There is sufficient fragility in the European economy to threaten the survival of the euro.

In summary, it was noted that the session's conclusions were similar to last year's Brainstorming.

- The probability of a recession is low in the USA and Europe, and indicators are still positive, though the risks for 2017 are associated with the downside;
- Temporary positive shocks for the European economy are dissipating and some of the growth is likely to fade. There were risks from political extremism due to middle-class dissatisfaction, which did not feature prominently in last year's Brainstorming;
- The world economy can no longer rely on emerging economies as the main engine for growth (excluding perhaps south-east Asia and Africa) and although it is expected that Brazil and Russia will return to a growth trajectory next year, the outlook seems uncertain. In any case, the wide divergence of economic performance means that the importance of BRICs for the global economy has faded;
- China is likely to continue with its 'new normal', disrupted occasionally by mini-stimuluses or mini-cycles, which are detrimental to rebalancing in the longer term.
- Although India has benefitted substantially from low oil prices and its economic performance has been stellar, structural challenges remain and India's growth is unlikely to offset China's slowdown;
- Commodity exporters have taken a big hit as a result of the fall in commodity prices, with their growth prospects being revised downward. Fiscal buffers have been eroding fast while internal challenges have been on the rise.

Session II – The geopolitics of energy

In the MENA region, there are a number of different themes around risk, with different drivers. These can be broadly categorized into:

- The collapse of certain oil-producing states (such as Libya and Iraq);
- The longstanding regional conflict between Saudi Arabia (and its allies) and Iran.

The varied nature of geopolitical risk is illustrated by Venezuela and Nigeria, for instance; these are states capable of adapting to the low oil price environment, but they have seen the re-emergence of internal political tensions, with major consequences for oil supply.

Libya is arguably the least well-understood of all supply-side risks, as the situation is driven by politics. A few weeks ago, the broad market view on the agreement allowing the Unity government to be established was that it would lead to an increase in supplies. However, the new government is not properly underpinned by support from the east and west of the country, and the risk is that oil production will decrease. Eastern Libya will not accept any government that is propped up by militias. A paradoxical situation has emerged where the enthusiasm of Western powers to act against Islamic State (IS) has seen them supporting the Unity government but also, inadvertently, supporting militants in Misrata. There has thus been a misreading of the situation by Western powers. The control of oil production terminals will be the defining focus for competing groups and we could, in some scenarios, see tactical deals to reopen production in the south-west of the country. However, the long-term outlook (taking into account the hiatus in oilfield maintenance) is for production not to rise above 800 kb/d, in an optimum scenario where a full restart is possible.

In Iraq, the federal government faces fiscal difficulties whilst maintaining the fight against IS in the north-west of the country. This has short-run implications for capital budgets and for the ability to maintain production at current levels. There are bigger political threats in the medium term. The democratic dispensation that occurred after the 2003 invasion is breaking down, as we see the re-emergence of tensions between groups that had previously cooperated (for instance, Shia militias versus Peshmerga in the north). There is a consequent material risk to production in the south. Production in the Kurdistan Regional Government (KRG) area faces similar problems, not just in relation to oil sector issues (such as oilfield credit and financing) but also to the willingness of different competing factions within Turkey to allow the Iraq-Turkey Pipeline (ITP) to function. The risks in Syria and northern Iraq could start impacting infrastructure.

There is a nebulous but serious conflict between Saudi Arabia and Iran. Huge competing interests across a whole swathe of countries in the region have made it impossible for OPEC to operate in its traditional manner and this has had an impact on oil policy. It is unlikely that there will be an 'unfreezing' of this permafrost until there is a breakthrough on Syria, or on Yemen (talks are taking place on both). At the moment, however, there appears to be no potential change on the horizon. Political risk also relates to increasing oil supply – for instance, Iran's attempts at 'maxing out' on oil production could be partly to set high baselines for future OPEC agreements.

Discussion

The discussion opened with a question on the relation of geopolitics to oil prices and causality between the two:

> Are geopolitics starting to matter again for oil prices?

One argument was that geopolitics has always been relevant. Part of the recent oil price recovery had to do with supply disruptions in places like Nigeria, Libya, and Colombia. Geopolitics was arguably affecting investment plans (especially in a country like Iraq). The rise of non-state actors (such as the Houthis in Yemen, Shia militias in Iraq, and militant groups in Libya) has changed the nature of the 'geopolitical risk premium', as centralized states are being eroded. In the long term, oil companies

may have to deal directly with non-state actors on the ground. The geopolitical risk premium may not result in huge price rises, but we may see 'creeping price increases'.

Another point of view was that rather than considering the geopolitical risk premium on the oil price, one could question what the impact of low oil prices has been on politics. For instance, low oil prices are making it difficult for Nigeria's government to cope with new rebel groups. Similarly in Venezuela, where production could decline by 200 kb/d (although exact production levels are unclear). Another view stated that the shift from the 'geopolitics of oil' towards the 'geopolitics of the environment' was relevant in that it was forcing governments into making policy choices on alternative technologies, thus impacting oil markets.

It was pointed out that the discussion on geopolitical risks tended to focus mostly on potential 'flashpoints' in supply rather than demand. What are the potential 'extreme scenarios' on the demand side? These could include broader issues such as the perceived threat from Russia on security of supply in Europe and consequent demand-side choices, including the adoption of renewable energy and the move away from gas.

It was stated that the situation in Nigeria reflected 'new territory' in terms of geopolitical risks whereas, in contrast, Libya felt more like a 'recurring theme'. Could companies realistically recover in Nigeria, or did the current position reflect a permanent situation which would only be resolved if prices were high enough? One response was that the current disruptions in Nigeria arguably had their roots in the era of high oil prices; the previous president, who was from the south of the country, poured money into southern territories (the areas now creating disruptions). The current president reversed this policy, creating tensions between the north and south of the country. This is more generally related to the division of rents between the federal states and local communities. Abuja is likely to tackle the crisis through increasing expenditure. A question was raised as to how European refiners would deal with an escalation in the Nigerian crisis.

The discussion turned to relations between Saudi Arabia and Iran, against the context of the oil price downturn and the lifting of sanctions. In the 2015 Brainstorming Meeting, the expectation was that Iran would come back much more slowly than it has actually done (analysts expected Iran to come back at less than 0.5 mb/d in the first nine months). It is difficult to ascertain whether Iran can sustain its current production of around 3.7–3.8 mb/d into next year, and there are questions around the drawing down of storage. One view was that there has been no dramatic renaissance in terms of Iran's leadership, and the political interference by vested interests (which developed over the period of sanctions) continues to prevail. A lot of legislative work remains to be completed in order to operationalize the Iran Petroleum Contract and there is a considerable amount of opposition in Parliament. A counter view was that Iran is looking to increase its exports rapidly. Saudi Arabia's *de facto* leadership in OPEC has come at a cost in terms of setting first the price differentials, and the only way to recoup this would be if it was willing to cede the leading role.

Another view was that the confrontation between Saudi Arabia and Iran was intensifying through the former's much more assertive foreign policy stance (such as the war in Yemen, and the proxy war in Syria). This confrontation is creating a vacuum in many parts of the region, resulting in the weakening of many states – which are likely to be filled by non-state groups. The question was raised as to whether one could see Saudi Arabia and Iran cooperating to stabilize the region. One view was that the USA was no longer interested in reconciling the two parties. In the longer term, a continuation of this rivalry will further destabilize the MENA region (Iraq, Syria, Yemen, and Lebanon are just a few examples). One optimistic view is that the risk of instability getting out of control and spreading into their countries could push Iran and Saudi Arabia to cooperate. Another view was that the standoff is likely to continue unless a change of actors occurs – for example, Iranian reformists have tried to gain ground in recent elections to the country's assembly of experts, but hardliners have been pushing back. Another view was that Saudi–Iran relations varied with the oil price environment. In a low price environment, the two may be 'pushed to come together sooner or later'. A counter view was that 'toxic politics' between the two countries would prevent any such agreement. The conditions would have to

be ‘right’ for an agreement to take place; for instance, had Iran agreed to freeze at certain production levels in Doha, Saudi Arabia may have gone along.

A counter view was that other supply sources could come online relatively quickly to compensate for outages; if the market tightens and geopolitical risks escalate, these could be offset by North American shale within six months, thereby tempering the effect of geopolitics on price for the foreseeable future. An opposing argument was that US shale may be a marginal supply source but not an effective source for offsetting large disruptions – it may prove to be a ‘dimmer rather than a switch’. Questions were raised on the changes taking place within Saudi Arabia – particularly the adoption of Vision 2030, and whether this could imply a move away from holding spare capacity in the future, which would add risks to the mix.

A parallel was drawn between the position of Saudi Arabia, and Russia’s position in the European market. Dependence on export revenues has forced Russia’s government to consider both the commercial reality of the situation in which it finds itself and European reactions to gas markets. Despite the rhetoric around oil-linked pricing, there has been flexibility in contract pricing (the European buyer could go elsewhere if ‘the price is not right’). Russia is arguably prepared to break the monopoly of Gazprom’s position in the market. From a supply perspective, geopolitics has forced Russian oil companies to focus on their core assets, leading to a rise in exports.

Session III – The oil market

World oil demand has been stronger than expected; it is around 97 mb/d and could average above 98 mb/d next year. Growth rates are relatively low, but we see fairly large numbers off the base. European and US demand have been stronger than anticipated, but the bulk of growth has come from India, China, and the Middle East. On supply, a key question relates to what the supply curve looks like for conventional versus unconventional oil. There has been a reduction in capex of $400 billion across the oil industry. Most price forecasts have been predicated on the USA as the ‘swing’ producer but questions remain such as: what kind of price levels is this activated at, what are the timeframes, how much supply do you get, and after how long? US shale and condensates production is around 8 mb/d but is falling fast, raising questions around what sort of price and how many rigs are required to first stabilize, and then increase, production. Further, in a rising price environment, questions arise over when the USA could get back to its peak of April 2015.

Media coverage projecting US shale as the swing supplier has been inaccurate, and has not taken the US shale business model into account. The US shale industry invested 125 per cent of its cash flow (on average) into producing assets, and borrowed to put money back in. This was sustainable as long as the industry kept delivering on growth – that model is now arguably ‘dead’. The situation could start to stabilize as prices continue rising, perhaps by Q1 next year. But rather than the expected ‘V shaped’ recovery, we could see a much slower recovery. In terms of price responses, $50/barrel is sufficient to bring rigs back on, as the more aggressive shale companies still see plenty of prospects; however, the response will only be catalysed when companies believe that the price will *stay* above $50 (or above $60 for more conservative companies). It is estimated that around 300–400 rigs will need to be added to stabilize production. It can be argued that there has been overestimation of the shale industry’s resilience to price cycles.

On conventional supply, production this year is based on capex sunk during the $100/barrel environment. The capex in relation to $50/barrel oil will only be visible at the back end of next year, raising questions around future supplies, particularly in the North Sea and West Africa. Towards the end of 2017/18 we could see all producers pushing up towards full capacity and there are implications in terms of further structural shocks for an industry running ‘that hot for that long’; this raises questions around the need for ‘market management’.

Also notable is the fall in Chinese oil production (down by 200 kb/d, and possibly 400 kb/d by June), which is the result of ‘prices as well as politics’. Although the NOCs have cut capex, there has been a shift in thinking in relation to ‘supply security’ as China’s SPR can now hedge against it and it also has

supplies coming in from around the world. China's NOCs are moving into trading and have refining and storage assets overseas. However, the need to preserve employment in the industry places a constraint on how long this shift in strategy can continue. There is a tension between improving efficiency versus the need to maintain state entities in the oil industry as 'social and administrative units'.

Discussion

The discussion opened with remarks on the failure to understand the dynamics of shale; even those active in shale have struggled to do so, often leading to facile comments around 'where the shale breakeven price is'. It was noted that substantial production could be brought online at prices of $70–$80/barrel. However, in order to restart/sustain production, the entire supply chain would need to be rebuilt. Large-scale redundancies have taken place, and infrastructure will need to be put back in place. Shale producers might find it difficult to ramp up the rate of completions if they cannot field enough workers, as fracking crews have been dismantled. An example was provided for North Dakota, where more than 50 per cent of people employed in shale have left the industry. The shale industry has the capacity to increase by 1 mb/d or more, but this is contingent upon the rebuilding of the supply chain, which could take nine to 12 months. A related view was that as activity picks up, cost inflation would return in parts of the shale industry, which would increase breakeven prices. But it was noted that the service industry will be unable to fully capture a larger part of the rent; service costs may therefore not pick up straightaway and there may be a lag. The issue of 'half-cycle' versus 'full-cycle' returns also matters in the calculation of IRRs at different oil prices. A related view was that shale companies needed $65–$70/barrel in order to generate a long-term 'decent return on capital'. It was also pointed out that hedging was getting expensive for US shale producers, and was increasingly becoming contingent upon debt round negotiations – this puts another implicit 'cap' on the revival of US shale production.

The decline in conventional offshore production, the lack of new investments over the last three years, and the inability of US shale to respond quickly will imply a future supply shortage. The inability of the market to fill this shortage could even lead to a price shock in three to four years' time. A return to $100/barrel oil cannot be discounted in this regard. The ability of, in particular, non-OPEC suppliers to produce an extra barrel is limited relative to their position in the 1990s, and their decline curves are much steeper than those of OPEC producers. The majors who went in this year with budgets assuming a $60/barrel breakeven price are below their breakeven and are making big losses. This was 'psychologically damaging' to the industry and arguably an underlying factor for continued cuts, despite the prospect of an oil price recovery.

Another view was that companies were cutting capex before the oil price decline and they were borrowing to pay out dividends. The current situation is reminiscent of the late 1990s when there was a consolidation phase: at a time of low oil prices, as dividend was 'sacrosanct', the preference then was to cut all other expenditure. Notably, companies started spending again nearly six years after this consolidation phase. A comment which supported this view was that on looking at companies' forward guidance on spending (which remains low to flat), another round of capex cuts would come in 2016.

The discussion moved to demand, and whether it too had been misread. The perception of consumers is that prices will remain 'lower for longer', and this is shaping demand behaviour. Efficiency improvements and the 'lower for longer' perception could create a rebound effect that could drive demand higher.

The discussion then turned to OPEC behaviour, a major source of uncertainty in the oil market given various conjectures over Saudi Arabia's intentions with spare capacity and productive capacity – for instance, one conjecture relates to whether the Kingdom would increase productive capacity to 15 mb/d. One view was that while going from 10 to 11 mb/d has little impact and the move from 11 to 12.5 mb/d is still relatively low cost, going from 12.5 to 15 mb/d would involve more pipeline and core capacity and steeper costs, and would require massive investment. More generally, it is quite difficult to reconcile the Kingdom as having a 'Vision' for decreased reliance on oil by 2030 with the prospect

of further expenditure on increasing oil productive capacity. Even under King Abdullah, when oil prices were high, the expansion of oil productive capacity was too big a commitment to make.

Rather than increasing capacity, Saudi Arabia's focus is likely to be on increasing the share of gas in its energy mix and pursuing efficiency measures more aggressively to free crude oil exports. It was noted that a push for gas (in power generation) was a realistic possibility in Saudi Arabia – in August 2015 the Kingdom used 900 kb/d in power generation, which represents a huge swing in demand. We can read between the lines to see that the brief of the oil ministry has changed and the entire power sector is now included within the same planning process as the oil sector. Further, given the potential for efficiency savings in oil consumption, it was more realistic that Saudi Arabia would pursue demand-side measures in response to the changing market environment.

Another view was that some of the policy intentions (such as the flotation of Aramco and attempts to dismantle price subsidies) suggested a longer-lasting structural change in the energy sector and oil policy, and a move away from market management to influence the oil price. The main implication of these changes is that the market could see more low-cost, relatively unconstrained, supplies. A related view was that there is very little room for producer cooperation in a falling market, as producers have the incentive to produce at maximum capacity in an attempt to increase revenues. A counter view was that producer cooperation could not be completely discounted, as producers could rally around a common threat (for instance, as in the Jakarta meeting).

A question was raised over the parallels of the 2014–16 cycle with previous cycles, particularly 1986. It was noted that the current strategy could never have worked in 1986, as at that time there were a large number of offsets in the system, such as flexible fiscal systems (for example, in the North Sea) and room for demand substitution, which are arguably lacking in this cycle. Fiscal terms cannot get more liberal without providing subsidies, and industry costs have not gone down materially in mature areas.

Some comments were made on Iraqi output, which was greater than expected last year and the authorities have just about managed to keep production going. But the sharp decline in oil revenues has altered the outlook for Iraqi output. The distinction between how much production will come from the north of the country versus the south is unclear, and it is contingent on the 'insulation' of the south to political upheaval. In the Kurdistan Regional Government (KRG) area, there has been an erosion of relations between companies and the KRG and this is likely to impact the next tranche of production; in 2017 it could be 200–300 kb/d lower. The low oil price in the KRG area has led to a massive deficit and oil companies have not been paid. Allegations of corruption have worsened the situation and have led to a lack of overall investment. There have been reserve downgrades across the board that have been attributed to low oil prices, but which may actually be due to technical reasons such as changes in the recovery factor. Companies get a slim margin from selling into the domestic market and production is likely to be in decline over the next 12 months. In the south of the country many logistical challenges remain, and in face of declining oil revenues the government has been forced to cut its investment in the oil sector. It is unlikely that these issues would be resolved if contractual terms were reformed – for instance if Iraq moved from Technical Service Contracts to Production Sharing Contracts – as the problems relate to rising costs, access to water, and logistics. There was strong consensus that Iraq's oil growth prospects look gloomy for next year and that it will not repeat the robust performance of 2015.

On Iran, one comment was that the US sanctions have not ended, but are on a 90-day renewal cycle with several restrictions still in place. Any subsidiary entering Iran cannot have American employees at any level, is limited by the list of technologies subject to sanctions, and cannot to do business with individuals or organizations listed as having links with the Revolutionary Guard. The US presidential election has also slowed progress. For all practical purposes, Iran remains 'closed' for foreign investment at the moment and hence the government's plans to increase productive capacity are most likely to be delayed.

The session concluded with a summary.

- Demand is likely to grow by 1.2–1.3 mb/d with an upside risk, presenting a relatively healthy picture.
- Non-OPEC supply outside the USA has seen some year/year declines, for instance in China, Brazil, and Canada. The picture of non-OPEC supply outside the USA is quite bleak. Despite projections of a price recovery this year, companies will continue to make cuts due to pressures from financial markets or as a result of investment decisions being made 'looking back rather than forward'. This will lead to sharp declines in supply starting around 2018/19.
- US shale production, which experienced 1.25 mb/d of growth in 2014, is now in decline, and increases in Gulf of Mexico production will not offset this. Even if prices go up, we are unlikely to see a 'switching on' but rather some stabilization of output, at $50–$60/barrel. A sustained revival of production will require higher prices and longer lag times.
- With demand growing and non-OPEC and US shale production falling, the supply picture reduces to the issue of OPEC behaviour. In 2015, Saudi Arabia and Iraq increased production, but Iraq is unlikely to be a growth area in 2017. Iran's re-entry to the market and restoration of its production has surprised on the upside and has helped offset some of the current outages.
- A key determinant of OPEC behaviour will be Saudi Arabia's response: in the short term whether it increases production in response to fiercer competition, and in the long term whether it increases its productive capacity. From the discussion, it seems that it may not have the incentive to do either.
- In such a world, there is likely to be a supply shortage around 2017/18 and the only way to clear this will be through the price mechanism. Although inventories could cap the price, we already see commercial inventories going down, as well as a large part going into SPRs, which may not return to the market.
- This conforms to a cyclical view of the market but with the nature of cycles having changed, though there was no agreement whether we will end up with more volatile or less volatile price swings and shorter or longer price cycles. For instance, external factors such as climate change policies could induce large oil market players such as Saudi Arabia to moderate cyclical swings. The cycle has also introduced a lot of cheaper oil into the market, which could dampen the extremes of the cyclicality. However, the deep cuts in investment could result in shorter cycles but large price swings.
- On the rationalization of costs in the industry, it can be argued that this has a cyclical component, but also a structural one. There was a general feeling that IOCs have not undertaken structural progress in controlling costs. Another view is that as soon as activity picks up, we could see cost inflation back in the system. The squeezing of service providers has affected their ability to be resilient in future oil price shocks/cycles.

Session IV – The products market

The majority of international oil trade occurs via ships, and it can be extremely difficult to forecast forward, particularly for arbitrage-driven trades. Product trade flows tend to vary considerably and to be contingent upon factors such as refinery disruptions. However, there is a strong correlation (around 95 per cent) between the volume of products trade and oil demand growth. For instance, in 2015 refinery output grew by about 2 mb/d while oil demand growth was approximately similar at 1.7–1.8 mb/d; this led to a product trade growth of around 12 per cent. This year we see a different trend. Although refinery output during the first four months grew by 1.0 mb/d, demand declined seasonally (quarter/quarter) and trade also declined. One reason for this is that refineries have essentially pre-empted the expected oil demand growth in Q3 and Q4, and some of this product is in stocks and floating storage (the latter being small in proportion to crude floating storage). We could see the

products market begin to come into balance in Q3, when demand catches up. One question that arises is whether additional demand will be met by higher refinery runs or from the drawing down of stocks; while another is what the sources of both demand and supply for the various types of products would be. An example of where we see divergent trends in product demand growth between different fuel types is China, which has seen strong gasoline demand growth domestically and has thus raised refinery runs; however declining gasoil demand in the domestic market means that the country has been exporting more gasoil. India's demand for products is increasing, but it has insufficient refining capacity to meet this, implying that they will either reduce product exports or increase imports (currently, they are reducing exports). The USA has no incremental refining capacity that could be tapped into, aside from small units or condensate splitters; the question therefore arises as to whether they should draw down stocks or import during the peak summer demand season. European refiners affected by the disruptions in Nigeria and strikes in France may be similarly forced to draw down stocks, or import Asian/east of Suez products. In the Middle East the opening up of two huge refineries since last summer has created a lot of trade in the region. However, plans to open further new refineries have now been delayed until the end of the decade.

There is likely to be an increase in the overhang of gasoil by around 300 kb/d this year unless stocks are drawn down, which could challenge the existing storage capacity. A related question is whether refiners can find margins on gasoline to offset the loss on gasoil. Last year was a story of gasoline in Asia, but we are unlikely to see the same high cracks as last year. Lower margins give rise to the question of whether there is room for growth in refinery runs even at higher oil prices. The glut in diesel could begin to clear from next year as non-OECD demand rises to replace losses of OECD demand. New sulphur content regulations from the International Maritime Organization (IMO) suggest reducing the limit on fuel content for ships, which could shift around 2 mb/d of fuel oil into diesel – if this happens, Asia could turn into a net importer of diesel from being a net exporter at present.

In the USA, a few years ago there was much discussion over 'peak gasoline demand', but the opposite seems to have occurred. Similarly, the 'death of European refineries' was also talked about; although these came back onto the market in a big way in 2015, it was not a permanent 'revival'. We could see a couple of closures by the end of 2016.

China's teapot refiners – a disruptive force?

There are 120 'teapots' or independent refiners in China, the majority of which are located in Shandong province, representing an estimated total capacity of 3.4 mb/d (although this could be higher). Although China's central government has attempted to shut them down, teapots are supported by provincial authorities as they contribute to petrochemical facilities in the provinces. Teapots were also effectively swing producers during supply shortage in the 2000s.

As China does not have truly 'private companies' teapots do ultimately have connections with the state. They are very creative on invoicing and taxation. They have rights to import crude oil directly, or to use imported crude oil. Since July 2015, 13 teapots have received crude from both avenues amounting to around 1.1 mb/d; this implies that a substantial amount of import quotas have been granted to teapots when compared with China's total crude demand (7–7.5 mb/d). The reasons for this include (a) the liberalization agenda; (b) using quotas to encourage the consolidation of teapots (on paper, around 1 mb/d of capacity has been shut); and (c) to sustain local economic growth. Notably, the governor of Shandong province is a former banker and one of the architects of the Shanghai futures exchange, and he has been encouraging liquidity in the system through teapots. The teapots themselves claim that they are being used to add to stocks, after which they could be shut down and taken over by the majors. However, there are more teapots awaiting quotas and licences and these could amount to 1.7 mb/d; some of them have even been receiving domestic crude. Not all of the 1.1 or 1.7 mb/d are incremental crude imports as some of this quantity is displacing existing imports – the incremental figure is more likely to be around 800 kb/d.

Teapots do not have access to ports and only one has access to a pipeline. The consequent trucking of crude has been boosting the logistics and infrastructure-related industries. Teapots do not have the

financial capacity to import Middle Eastern crude, which could take two to three months to be delivered. Rather, they have been playing around various obstacles in the domestic market to obtain their crude on favourable terms. Crude purchases by teapots could slow down over the next few months due to a backlog; however, they are more likely to keep buying than to cease completely, as a new pipeline in Shandong is expected to ease some of the congestion. The majority of teapots sell products to the majors and claim that they lose out on margins; but in reality they receive tax exemptions from local authorities and can therefore sell at a discount. There is also an active trade in quotas and there is a likely oversupply from teapots which will need to be exported. This could be a two to three year story, as teapots will eventually need to be consolidated.

Exports of gasoil from China may be going under the radar at the moment. Suez Maxes and VLCCs being delivered in South Korea and Japan tend to take gasoil as their first cargo until they relocate to western markets, which bodes well for Chinese gasoil exports. This could further pressure European margins and affect European runs.

A question was raised as to whether the glut of diesel in the products market was weather dependent. It was stated that El Nino was followed by lower than usual diesel demand, but that this year La Nina could indicate a harsher winter and consequently higher demand during Q4. However, the main impacts of the glut were likely to be felt on the market in Q3.

Session V – The oil industry

The session largely focused on the future of Saudi Aramco and implications for the industry and global energy markets. The proposed Initial Public Offering (IPO) of Saudi Aramco is one of the biggest challenges for the new Saudi energy minister. There has been an attempt to separate the chairman of Saudi Aramco from the oil ministry. This seems to have created problems, and what we see now is that things have come ‘full circle’, as the new energy minister is also the chairman of Saudi Aramco. Saudi Aramco’s IPO is a core aspect of Vision 2030, which is a top priority of the current administration. The market expects that Aramco will float in 2017, but this may be unlikely. There are a number of challenges related to the IPO:

- Even a 5 per cent float on Saudi Arabia’s stock exchange will overwhelm its stock market as it is small relative to global markets. As an alternative, it could float on the London or New York stock exchanges. However, the result of listing on these stock exchanges risks Aramco being subject to frivolous lawsuits.
- There has been a lot of confusion over the valuation of the IPO. There was speculation over whether Aramco would privatize its reserves. However, in a recent interview the oil minister clarified that the reserves belonged to the government. Therefore, the basis of any valuation will not be on the value of the reserve base, but most likely on the discounted cash flows into the future, which depends on the profit per barrel and the quantity of oil produced. But this is where it gets complicated. The profit per barrel will depend in large part on the level of taxes and royalties Saudi Aramco pays back to the government; if the taxes and royalties that go to the finance ministry are high (which they currently are), then the valuation will be low.
- The IPO also carries a sovereign risk as the government, as the biggest shareholder, can take more revenues out of the firm. Hence the comparisons with private companies such as ExxonMobil do not hold, as one cannot apply the same discount rate to Aramco’s cash flows given the higher level of risk.
- The IPO is also likely to influence other aspects of reform such as pricing reforms in gas and other products. For instance, in the current environment of low domestic gas prices, it is not clear how to value the gas assets of Aramco, as most gas is sold at a very low price for domestic consumption.

It was pointed out that a listing overseas would expose Aramco to a number of obligations, such as conforming to SEC standards on reserve accounting even if the reserves belong to the government.

Such a listing would involve a major change to the way that the Kingdom has run its policy, in terms of requiring greater transparency. For instance, this may involve an annual independent verification of its reserves. It was noted that Aramco may not necessarily be immune to some of these processes even if it went for a Riyadh listing.

A question was raised as to whether Saudi Arabia would defer the IPO if oil prices improve and fiscal pressures ease. One response was that the IPO is a central part of Vision 2030 and for the Kingdom to step back from it after raising the profile of Vision 2030 would be extremely difficult. Therefore, the IPO will go ahead, but there is uncertainty over whether it will represent a 'true' IPO or 'something which resembles an IPO'. It was unlikely that this would change unless there was some sort of radical change in political power.

A comparison was made with the privatization of Rosneft, which floated 5 per cent of its shareholding, and faced similar issues of valuation. It turned out to be something of an embarrassment, as international investors were uninterested in buying due to concerns similar to those outlined above for Aramco. Rosneft had to scramble for strategic investors, who were forced to buy into the stock. Despite $100/barrel oil prices, there have been barely 12 months in which the price has been above the IPO level since the flotation. According to a counter view, it was unfair to compare Aramco with Rosneft as the latter undertook privatization whilst mired in the Yukoil scandal. Another example was provided of a 'privatization gone wrong' in the sale of BP's share in the UK; this was bought up by KPC, with a massive impact on BP's share price. Another view was that as production was likely to remain flat for the next 10 years, investors would want a substantial dividend/return on a company with low growth prospects. A question was raised as to whether Aramco could instead consider a bond issue – one response was that Aramco's IPO is meant to reflect Vision 2030, which aims to bring in transparency. An (incorrect) assumption being made was that Aramco is 'selling its resource' but this is not the case – rather, the IPO is about increasing the exposure of the Saudi economy to the outside world. The consensus was, however, that the IPO will go ahead in some form and it is being taken seriously as part of Vision 2030.

Changes in regulatory landscape and benchmarks

The effective functioning of a trade-driven benchmark requires the creation of certain conditions, and a platform where shorts face longs and the price emerges with a minimal amount of interventions. However, a huge amount of discipline is required on the part of market participants. Mechanisms such as a 'divide and conquer' approach are utilized to ensure that no single player is large enough to game the price. With regards to the Dubai benchmark, it can be argued that this discipline has been lost to some degree, as some PRAs inadvertently attempted to adopt a 'friendlier' attitude with customers to ensure that relationships were sustained, without realizing that the role of the benchmark provider is to create the tensions necessary for price discovery. Further, several companies have been seizing large percentages of the open interest. This is likely to continue until such time as either market organizations respond or an external agency intervenes. However, regulatory intervention has also been criticized, as market solutions are viewed as being the most effective. One view was that Dubai prices have not been reflective of pure market outcomes. Last year, we saw episodes when the Dubai price was higher than Brent, which did not make sense. We saw the inverse in early 2016 when a new crude was added which was incompatible with the other components of the Dubai benchmark; Dubai was 20 per cent below Brent as a result. It was pointed out that whilst the lack of market discipline was one problem, the underlying problem was the lack of sufficient crude (liquidity) in the Dubai market. Aberrations could not be fixed by regulators, who are not as nimble as the traders. One view was that a potential solution was to give the market something that is less easy to leverage than a single price and to think instead in terms of 'baskets' containing some Platts price, some Argus, and a DME price. This approach could potentially mitigate the damage that could result from dislocating a benchmark. An alternative view was that this is the wrong way to approach the problem.

Session VI – Gas, LNG markets, and pricing

European gas demand

The global economic crisis has impacted energy and power demand; European gas demand peaked in 2008 (2010 if not weather corrected) and declined until 2014 across all sectors (except for transport which is only 1 per cent of European consumption). The largest decline has been in the power sector; this has been a big shock for gas market players and a 'wake up call', as gas-for-power demand was expected to be the main driver for gas in Europe. In addition, the impact of further efficiency measures, due to policy directives by the European Commission (and collateral effects of the economic crisis which saw the least efficient plants closed down first) are starting to kick in. Renewable capacity was politically supported and got priority dispatch in the merit order. As power demand began stagnating, there was less room for other fuels. Since 2011, coal prices have fallen by 50 per cent and the EU ETS has failed to perform, due to a surplus of permits which pushed carbon prices down from 25 euros/tonne in 2008 to between 5 and 8 euros/tonne since 2013. Coal therefore became competitive relative to gas, and the latter dropped in the power mix from 24 per cent to 16 per cent in 2015 – the displacement in market share came mainly from non-hydro renewables. The share of coal increased in 2010–12 and then declined again; it is currently at 2010 levels due to the closure of coal capacity resulting from the Large Combustion Plant Directive. A cold winter led to an increase in gas demand in 2015 and renewed optimism from gas players. In the UK we see coal-to-gas switching occurring thanks to a carbon price floor (a national measure which comes on top of the EU ETS price and which reached £18 per tonne of carbon dioxide in April 2015); there have been some days when there has been no coal in the power mix (not seen before in the last 100 years). However, the UK's situation cannot be easily replicated in other mainland European countries as the UK has room for switching between coal and gas. Further, a lot of coal plants have been retired in the UK due to the LCPD, and being an island market the interconnection issues are fewer.

Although gas prices have fallen, especially since late 2015, they would probably need to drop below $3.5/MMBtu in (western) Europe before switching starts to happen for baseload generation (they are at about $4–$4.50/MMBtu at the moment). The Industrial Emissions Directive (IED) will result in some capacity being removed from the market, but exactly how much is uncertain, as Transitional National Plans provide countries with time to decide whether they will invest or opt out. Some countries have decided upon a phasing out of nuclear, which will lead to an overall reduction in generation capacity – and there are questions over how this will be replaced. Renewables cannot fill this space within the required timeframe, and the effect of new coal and nuclear plants will be – at best – limited. New large hydro projects with reservoirs will also be constrained for environmental reasons, and new projects will likely be 'run-of-river'. If left very late, the best option will be gas. Even in a world of tighter and lower carbon emissions, there is a possible role for gas in the generation mix in Europe, but this will require that enough gas plants are in place and ready to be used (which is still uncertain) and that the gas industry manages its high-carbon status in the 2020s and beyond (by developing power stations equipped with CCS technology). The demand growth scenarios (early estimates) presented at the Brainstorming for Europe suggest a potential for 10–15 Bcm growth by 2020 and 60 Bcm by 2030, compared to 2015. (Europe = EU28 + Albania, Bosnia and Herzegovina, Macedonia, Norway, Serbia, Switzerland, and Turkey.)

Indigenous gas production has been declining – although the UKCS increased from 2014 to 2016 it is then set to plateau and decline. In Norway, the projected plateau is set at 100 Bcma post 2025 (and up to 2035) but there are questions around whether they can develop their 'yet to find' reserves in the current gas price environment. There is major uncertainty from the Netherlands; in Groningen, concerns over earthquakes have constrained production. The latest cap on Groningen production is 27 Bcm for 2015–16, or half of what was produced by the field two years ago. There are no predictions for future production from the Groningen field, although it is unlikely that its production will rise higher than 27 Bcm and total production is expected to be in decline. An overall European decline

in conventional production of 95–123 Bcm is likely by 2030 (compared to 2015), which will not be compensated by unconventional gas and biofuels production. Because demand is expected to rise by 60 Bcma, Europe will need ever more imports.

Asian LNG

The surge in LNG imports, combined with Gazprom's huge surplus capacity, has overwhelmed the market. There are seven Australian LNG projects coming onstream in the near future; the USA has some producing projects and five or six due to come online. Supplies of around 170 Bcma will arrive in the market at a time when European demand has stagnated and Asian demand is not meeting expectations. This raises some key questions: how bad might the gas oversupply glut be in global markets? When can it come to an end? And, how will players respond?

Various scenarios of demand modelling can be carried out for Asia, based on China's demand, coal displacement (how much and where), Japan's nuclear restarts (and across the rest of Asia), former exporting countries becoming importing countries, and gas demand increasing. The modelling of a range of expectations sees the glut being cleared between 2021 and 2025 assuming no new FIDs. How this pans out is contingent, to a large extent, upon Russia's export strategy. Gazprom's production has fallen from 550 Bcm to 420 Bcm, which is partly a reaction to demand – both domestically and in the FSU countries. It has 130 Bcm of spare capacity as it invested in Yamal at a time when European gas demand appeared to be on a rising trend. Other estimates put Russian spare capacity at over 200 Bcm. This implies that Russia could double its exports to Europe in pretty short order and at Short Run Marginal Cost (SRMC). Gazprom Export have stated their intention to defend market share in Europe, whilst also denying that they want to start a price war. Gazprom's SRMC depends to an extent on the value of the rouble versus the US dollar, as half of its production costs are domestic. Its breakeven cost is $4.25/MMBtu to deliver to the German border (excluding the 30 per cent export tax, this drops to around $3). It is clear that Russian gas is relatively cheap and Russia can compete in a falling gas market. The 200 Bcm bubble does not include any gas intended for China and the Asia Pacific region; there is the potential for 100 Bcm of gas to go into China and the eastern markets, contingent upon how much gas China decides to take from Russia.

In terms of Russian strategy going forwards – Russia is in a similar position to Saudi Arabia (but in the gas market). Despite its protestations that its contracts remain oil-linked, it is showing increased flexibility in contracts – offering to match hub prices, and in some contracts to guarantee customers a margin via rebates. It has started to run auctions for gas on the Nordstream pipeline. In the long term, it makes sense to keep the price below $7–$7.50/MMBtu to disincentivize new LNG projects. The whole issue of 'unburnable carbon' is also relevant to Russia. Unlike oil, the outlook for gas is not bullish on price for the rest of this decade, and it makes economic sense for one of the largest gas market players (Russia) to keep prices down. The question of the link between oil and gas prices is relevant going forward. If one conclusion from the oil market session is that oil prices could rise to $70/barrel, that raises questions for producers who still think that gas prices are linked to oil, and that a rise in gas prices would result in two situations: 1) make Gazprom uncompetitive again, taking the market back to early 2010 when Russian gas provided the cap for flexibility on prices; and 2) the faster oil prices rise, the faster the rouble would appreciate against the US dollar, and the faster Gazprom's cost base would go up.

China's gas demand

The market is bearish on Chinese gas demand. We have yet to see a Thirteenth Five Year Plan for oil and gas and there are no concrete targets up to 2020. The initial plan was for gas to replace coal in the transition to renewables, reaching 400 Bcm; however, this is more likely to be around 270–290 Bcm. Gas is a question of policy in China. It is mainly used in transportation, city gas, and industry and is very price sensitive. Industry pays three times more than other sectors for gas, and it is currently undergoing a slump, or low period. The gas price is linked to LPG and coal, and there has been a lot of fuel switching from gas to LPG, but following a price cut we can see natural gas

recovering a bit in China. The government wants to protect consumers, but also to encourage the development of shale, and therefore has to walk a 'fine balance'. The gas pricing mechanism is not very flexible and the monopoly of the majors (or how to open them up) is another issue. The downstream sector has begun to open up – and there are private gas traders. There are plans to create a new pipeline company and to link upstream and downstream, but this is a bone of contention between NOCs and the government, and may possibly be blocking stellar gas demand growth in China. The Chinese have lined up a huge amount of gas supplies, and are trying to amend contractual terms on LNG deals. The key is getting the pricing right and building out domestic infrastructure. The longer this takes, the harder it will be to get wider levels of gas penetration in China. The other issue in China is security of supply – China does not want to rely too much on imports, and so needs to encourage domestic production, but this is difficult at low gas prices. The future of Chinese gas demand may rely to an extent on how domestic production progresses. Also, we need to be aware that the mix of imports is important – 50:50 LNG: pipeline seems to be the optimal outcome, although at present flexible and cheap LNG seems to be preferred.

Transportation

There has been much discussion on the potential for CNG in transportation as an area of gas demand growth. In India, private vehicles can be retrofitted with CNG kits and there has been significant penetration of CNG in road transport. In the USA, there are trains that are switching to gas. In China, subsidies and policy support have helped natural gas vehicles; the NDRC estimates that gas demand from transport will reach 32 Bcm (of 290 Bcm) by 2020. In shipping (container ships, ferries, and cruise ships), there are restrictions on gas use, although these stem from refuelling capabilities rather than price. IMO regulations requiring ships to use fuels with a lower sulphur content are likely to have an effect around 2020 or 2025. Shipping uses around 3 mb/d of fuel oil at the moment; this will be replaced by diesel (around 2 mb/d) and then by gas (around 300 kb/d). The IMO has to mandate the changes by the end of this year; the EU will apply the regulations from 2020 onwards. LNG bunkering infrastructure is becoming available in Europe – notably, bunkering can take place from an LNG ship, and not just a land-based facility. These developments are relevant for future gas demand in transportation.

Discussion

It was noted that the gas cycle is very different from the oil cycle – the suggestion of a rebound in oil prices in 2017 and a persistent oversupply in the gas market implies a massive divergence between oil and gas prices.

It was stated that gas has been competing with the wrong fuel for too long – namely, oil rather than coal. Gas does not have a captive market and needs to compete with other fuels. As a result, lower gas prices do not automatically translate into growing demand, as it depends on the competitiveness of gas prices against the prices of other fuels. Coal prices have collapsed and gas is still not competitive with coal. In the UK, we have seen some coal-to-gas switching, but with limited impact on total gas demand in 2015.This is because although coal's share in the generation mix was cut in half (from 2011 to 2015), there was limited room left for gas to expand to fill the gap, due to growing renewables (and declining power demand). At the regional level, OECD Europe has lost about 75 Bcm of gas demand over the last five years – equivalent to the size of the UK market. It is unlikely to return to that level, as power demand is not strong and the share of renewables has grown considerably. In Europe, support schemes for renewables have interfered with market signals, disadvantaging gas on the whole.

The discussion turned to Japan, where it was stated that gas demand was entirely subject to nuclear policy. METI has announced that 20–22 per cent of nuclear capacity would be retained (equivalent to the share of renewables) in Japan's energy mix. Japan is due to begin receiving LNG supplies from Zeebrugge this year. However, nuclear in Japan is subject to political influence. Elections to the Upper House are due in December, and could result in an election being called in the Lower House

as well, as Abe seeks to cement his popularity. If he wins, we could see new-build nuclear reactors (although this is subject to change as well). Japanese LNG buyers have achieved price diversification to an extent, and hence gas in Japan is an issue of 'flexibility', particularly in relation to nuclear.

A question was raised on whether US LNG would be transported to Europe at low gas prices. One view was that West African gas landed in Europe was around $1/MMBtu cheaper than US LNG (which is estimated at around $7/MMBtu including regasification and transport costs). A counter argument was that the USA is the lowest-cost provider and the cheapest place to build capacity; essentially the 'cost curve is king'. Buyers may go for diversification and pay more (for security of supply).

It was pointed out that the US shale industry operates on two time horizons. Long-term contracted gas was being contracted five years in advance, due to negotiation and construction lead times. The USA also moves volumes between markets at short notice (5 per cent is traded in prompts). A third is traded on a yearly (or less) basis. Hence there have been dual horizons in the same industry, but these are increasingly being blurred. On the link between oil and gas prices, it was noted that this was partly a result of the indexation in long-term contracts as buyers were 'comfortable' with this. (An alternative could be indexation to Henry Hub). Consequently, when oil went to $100/barrel, long-term contracted gas in Asia went up to $15/MMBtu, while the spot price went to $19/MMBtu in Japan. Another view was that the USA has put in place a large latent supply and future volumes can come on at a price that sets a cap on future gas prices. Thus, even if we go back to $100/barrel oil, gas will not be priced up equivalently. Price will be increasingly determined by the cost of supply for long-term supply (for the USA: $7–$8/MMBtu into Europe, and $8–$9 into Asia; and for large conventional projects in the $8–$10 range). There could be a fundamental change from scarcity pricing against the high end of the fuel spectrum, to something which competes on a cost-plus basis. The conundrum is that at $7/MMBtu you are too expensive to compete with coal without carbon pricing. A price of $3.50/MMBtu is insufficient to bring new supplies online, and as a consequence the gas industry could swing to a boom/bust cycle, swinging between extremes.

Another view was that Europe would effectively be the 'sink' for LNG, and due to coal switching and the overflow market, could effectively be a price setter. It was reiterated that coal–gas competition in Europe is somewhat contingent upon timeframes. Large quantities of coal-fired capacity will be removed from the mix by 2025/30, and coal–gas competition could become less relevant for the power sector in Europe. The UK is projected to have no coal plants by 2025. Another view on coal–gas competition was that gas is currently conflated with shale gas and fracking. On a Btu basis, gas generates 50 per cent of the CO_2 that coal does. Despite this, Germany brought on five new coal plants last month. It was pointed out that the load factors of renewable energy in Europe are extremely low: solar energy in Germany is about 2 per cent in the winter and about 17 per cent in the summer; Spain's load factor is around 35 per cent in the summer. While regulators are preparing the field for 50–60 per cent renewables in Europe, its feasibility is questionable at best as the interconnections currently all favour coal.

A question that was posed was: has gas lost the battle as a clean transition fuel? The argument that 'gas would be the default fuel when coal is removed from the system' was being used five years ago. At present, gas-fired power generation is twice as expensive as coal. Gas plant is configured as peaking plant, and the peak happens to be in the middle of the day when solar and wind are plentiful. In Germany, the daytime gas peak has therefore become a trough. If the gas industry fails to act in terms of CCS and other measures, it could be hurt even when coal is backed out and gas becomes the highest carbon emitting fuel.

It was pointed out that the future of gas relied on a number of assumptions – for instance, *if* coal were to be removed from the energy mix in Europe, *if* nuclear restarts in Japan were to falter, and so forth. This is not a good foundation upon which to make an investment with a four to five year time horizon to operation. Russia is the only country with spare capacity in gas – one scenario is that by 2021 Russia will 'pick up the slack'. However, this was subject to political risk, in terms of European politicians preferring to keep LNG in the mix to avoid Russian gas dependency. There were conflicting

views around the subject of whether Europe was a growth market for gas or not. The 'battle' between the USA and Russia in the gas market will be a battle between Henry Hub, and the rouble/US dollar exchange rate, as the latter will influence domestic production costs, royalty and transport costs, and hence the breakeven price, in Russia. The Central Bank of Russia has made it clear that it will try to ensure that the rouble does not strengthen too much even if oil prices recover, in order to continue the country's cost competitiveness in the export market.

In conclusion;

- The gas and oil cycles are very different; gas prices will continue to delink from oil prices going forward, and the gas 'glut' will persist through to the end of the decade. In the interim, new LNG capacity is economically unviable.
- Going forward, perhaps a less pessimistic view on the gas market is that gas has not benefited from high prices over the past decade in Asia, and from having Gazprom as an 'awkward seller'; therefore, low gas prices and a 'more commercially realistic' Gazprom in the mix may result in gas becoming more competitive as an industry.
- The outlook for demand was less certain, as gas consumption has been driven by policy rather than market signals, and this is likely to continue to be the case unless gas prices remain low and competitive with the relevant competing fuels.

Session VII – COP 21 and its implications

The COP 21 meeting was held in Paris in December 2015 and resulted in 195 governments reaching an agreement (the Paris Agreement) to cooperate on what the global regulatory framework for preventing dangerous climate change post-2020 should look like. Countries have submitted their Intended Nationally Determined Contributions (INDCs), which are non-binding. These are to be assessed and updated every five years, with a view to holding the global temperature increase to well below 2 °Celsius. The Paris Agreement envisions a global peaking of GHG emissions and achieving emissions neutrality after 2050. Further, developed countries will need to find $100 billion a year to enable developing countries to finance the transition to clean energy. In order for it to come into force 55 countries, representing at least 55 per cent of global GHG emissions, will need to join the Paris Agreement. Countries representing the largest share (and potential future share) of emissions have agreed to join; these include the USA, China, and India. In a separate regional-level agreement (the Under2 MoU), 128 states and regions have also agreed to cooperate on carrying out climate change mitigation measures.

The Paris Agreement signals that 'business as usual' has ended. However, there is a gap between the pledges made thus far and what is required to achieve the global emissions reductions target – the IEA estimates that even if all INDC pledges are fulfilled, temperatures would still rise by 3 °C. In terms of what COP 21 means for industry, there are shorter-term impacts such as increases in decommissioning costs, and data requirements on emissions. The power sector will see the greatest transformation and, by extension, the gas sector. The impact on oil markets could be reflected in oil-producing countries having to compete for a share of reduced world oil demand, suggesting implications for the upstream industry. A lack of clear direction and signals from policymakers has created uncertainty around the impact on industry. One view taken by policymakers is that acting now could reduce the risk of ending up with stranded assets; another view is that technological advancements are likely to bring down costs in the future, and thus deferring the costs of adaptation is feasible.

One question, in light of the recent oil price fall, is whether renewables investment has decoupled from the oil price. The UNEP 'Global Trends in Renewables Investment' report estimates that there were $286 billion of investments into renewables in 2015, with the share of developing countries outpacing that of developed countries for the first time. China accounted for over $100 billion of this. India, South Africa, and Mexico also featured prominently. However, given the amount of investment

that will be required to finance INDCs, it is pertinent to note that renewables have not drawn a response from financial markets at levels comparable with oil and gas; their value is negligible in comparison with that of oil and gas equities and global corporate bonds, as well as oil and gas commodities, on global financial markets. Another issue that has gained some prominence is the movement for divestment in fossil fuels, which has been an emotive issue. It has had a significant impact on coal – for instance, US coal assets have lost 85 per cent of their value in the last five years. However, there is some debate over the effectiveness of the push for divestment – one argument is that 'there will always be another buyer in the market'. Another argument is that divestment would lead to a dramatic reduction in the value of investors' portfolios; it would take a considerable amount of time for these to recover and likely involve taking on riskier investments.

Discussion

The discussion opened with an invitation to participants to respond to the following question:

Will COP 21 alter the thinking of the energy industry?

One view was that a serious intent to 'do something' was prevalent in societies, and this was reflected through their governments. However, the INDCs do not indicate a constructive change. A 'relook' is required on how to achieve the INDCs through a 'more pragmatic' approach. Another view was that on paper, if the INDCs are pursued, the difference in terms of energy markets on a 30 year outlook will be significant. However, the mechanisms being put in place will not be effective in achieving this, especially as the issue of carbon pricing has not been clearly articulated (this is also a pre-requisite for CCS). Some mixture of CCS, renewables, and nuclear makes sense but the fixation on the 2 °C target models risked missing the opportunity to lay out a clear path forward. A more concerted effort was required between oil-producing countries on commercializing CCS. It was noted that, based purely on the political aspect, it is easy to take a cynical view. However, from a technological advancement point of view, the advent of driverless vehicles and other innovations imply that major changes are on the horizon. Further, COP 21 sent a strong signal to consumers and it is likely to catalyse changes in lifestyle choices, which are driven by culture rather than simply by economics. Another view was that in the short term, COP 21 was 'utterly irrelevant' outside the power sector, but in the long term, there could be changes.

A big change between the Copenhagen (COP 15) and Paris (COP 21) climate meetings is that the latter has been voluntary. China, for instance, is carrying out its INDC because it fits with its longer-term economic plan, with its 'Belt and Road' initiative having part of its financing going into renewables. It was also noted that public awareness had increased dramatically after COP 21 – international oil majors having expanded their communications and relations staff – and there is a sense that large energy companies prefer to be part of COP 21 rather than observers. It was, however, pointed out that 'not enough was being done by the oil and gas industry' in this regard. Further, in a low-price environment, the management's attention tends to focus on the short term. One view expressed was that oil companies and technology companies were 'living in parallel universes'.

A question was raised around the viability of Saudi Arabia's strategy of 'supply side management', given the potential implications of COP 21 for demand. In response, it was stated that Saudi Arabia's strategy, set out in Vision 2030, was about reducing its vulnerability to price volatility over time and diversifying its sources of energy. Other GCC countries such as Kuwait and Qatar were also seriously looking at how to integrate renewables in the power sector, although at the moment there is a disconnect between stated ambitions and actions being taken – for instance the potential transformation of Saudi Arabia from an oil to a solar economy. However, there has been a clear shift in thinking post COP 21 among producers with large reserves.

On the future of coal, it was pointed out that the only time we have seen coal displaced in the USA has been through lower prices for shale gas, and in the UK, through a carbon price floor.

A final comment was that unless there was a 'commercial solution' in addition to a political one, COP 21 is unlikely to 'work'.

Session VIII: Summary

The session summed up the main conclusions from the Brainstorming Meeting.

Prospects for the oil market this year are relatively healthy, with oil demand expected to grow by around 1.3–1.5 mb/d. However, the supply picture looks bleak: non-OPEC supplies are in decline. Cuts in capex are likely to continue through 2016/17, and despite predictions of a price recovery, it is unlikely that investment will rebound as oil companies will have to go through the cycle before regaining confidence. The subsequent impact on supplies is likely to be felt in 2019/20. US shale, which is in decline in 2016, is unlikely to be a 'switch on/switch off' source and will require a large number of rigs for output to stabilize and then increase at a higher oil price. This will leave OPEC suppliers to balance a tightening market; while 2016 has seen Iran enter the market, Libya remains an uncertain prospect. Saudi Arabia may have the capacity to increase production, but it would find it difficult to *sustain* production at levels beyond 11 mb/d without embarking on a new investment programme. Even if Saudi Arabia were to decide to expand capacity, this would be expensive and take time – requiring massive investment in calibrating the whole system, including increasing capacity processing plants and building storage facilities and pipelines.

In the event of a shortage of supplies, it was therefore highly probable that the only mechanism to clear the market would be price, and hence it is difficult to completely discount the recurrence of above $70/barrel prices. This raises issues relating to the impact on demand and the acceleration of climate change mitigation policies. It was noted that this outlook was a clear shift in sentiment from the Brainstorming Meeting in 2015.

The gas market was seen as following a completely different cycle to oil. The expectation was that gas prices are likely to stay low despite an oil price recovery, which could create some large price differentials. It is as yet unclear as to how this would impact substitution in oil demand. Given the different price cycles, gas pricing mechanisms linked to oil do not make sense anymore. It was also noted that gas could continue to proliferate in the energy market only at low prices. However, the future of the gas market is contingent upon many assumptions relating to factors such as: oil prices, climate change policies, carbon taxes, and the backing out of coal – some of these assumptions being inherently weak.

COP 21 was seen as having no impact on energy (oil and gas) markets in the short run, but it cannot be discounted in the long run. Rather than analysing it as a climate change issue, it is important to look at it as an issue related to technological advancements, consumer behaviour, changing public perceptions, and mobilizing citizen pressure on governments over environmental issues.

Looking ahead to 2017, the following issues were highlighted as being noteworthy or important to keep a watch on:

- oil demand growth, especially in areas where demand has been strong (India) or very weak (Russia and Brazil);
- the US shale response as prices start rising;
- fundamental changes in Saudi Arabia's behaviour as a result of domestic changes in its economy and in its energy sector;
- unplanned output disruptions in places like Nigeria;
- the impact of current capex cuts on non-OPEC supply outside the USA;

- whether capex cuts will continue in 2017 (it was noted that this would be the first time in its modern history that the oil and gas industry would have witnessed three consecutive years of cuts).

This concludes the notes from the Twenty-Seventh Brainstorming Meeting.