The Search for Global Energy Solutions

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With the immense changes in the industry resulting from the global economic downturn and its impact on the oil and gas sector, it is only fitting to set the focus of the World Petroleum Council Annual Publication on ‘Global Energy Solutions’.

Based on the outcomes from the 19th World Petroleum Congress in Madrid in 2008 we recognise that there are three main drivers: Investment, Innovation and Cooperation.

Investment in new infrastructure
Economic growth and liberalisation of markets throughout the world have spurred significant demand for oil and gas over the last decade. However, the global financial crisis has resulted in a steep worldwide recession which, along with volatile energy prices, has significantly impacted the oil and gas sector.

The global economic meltdown has resulted in a major cutback in investment in the industry, particularly in mega-projects. The IEA estimates global demand for oil to rise to 106 mb/d in 2030. 80 per cent of all energy comes from fossil fuels and that level is not expected to change very much by 2030. Much of this increase in supply will be coming from unconventional oil and gas which will require higher sustained prices.

These trends call for energy related infrastructure investment of US$26.3 trillion to 2030, which equals just over US$1 trillion/year. About half of that will be required by the oil and gas sector. According to the IEA, 64 mb/d of gross capacity needs to be installed between 2007 and 2030 – six times the current capacity of Saudi Arabia – to meet demand growth and offset decline. In the current economic downturn it is unlikely that these levels of investment will be met, although those that are cash rich and have access to credit will be able to pursue new opportunities.

Technological innovation
Conventional reserves of oil and gas that are easy to access and inexpensive to produce are largely gone. Accordingly, industry is exploring in ever more challenging new frontiers where large oil and gas discoveries are being made. The development of such new discoveries will require deployment of cutting edge technologies delivered in an environmentally safe manner.

Enhanced oil recovery is still one of the more promising areas to increase the reserves and production from existing fields. The development of new technologies is significantly increasing recovery factors and prolonging the life of mature oil and gas fields.

Unconventional oil and gas resources are quickly becoming technically feasible and economically very attractive. Advanced technologies and minimisation of environmental impact of developing and processing the reserves are key to the further development of these resources.

Cooperation
Notwithstanding the current economic crisis, many of the largest oil and gas companies are actually maintaining or raising their capital investments to address the ongoing need to add reserves and grow production. This brings about new opportunities for international oil companies (IOCs) to partner with national oil company (NOCs) on a long-term, sustainable basis. The downturn can therefore be a good time to focus on forming and strengthening strategic alliances, particularly with NOCs.

Cooperation between IOCs and NOCs is not without its challenges: there are significant cultural, philosophical and social differences between the two parties that can make working together awkward at best and sometimes impossible. In addition, the possibility of government changing the rules can pose a real risk and induce added uncertainty. Furthermore, government playing the combined roles of policy maker, regulator, partner and investor is a complex mix requiring considerable skill, understanding and flexibility. Notwithstanding these challenges, the potential rewards of enhanced cooperation are significant for both parties and indeed, there are many examples of successful partnerships. The World Petroleum Council (WPC) can facilitate the building of important bridges for the two sides to find ways to work together.

In the new economy, strategic alliances enable businesses to gain competitive advantage through access to a partner’s resources, including markets, technologies, capital and people. Teaming up with others adds complementary resources and capabilities, enabling participants to grow and expand more quickly and efficiently. Many fast-growth technology companies use strategic alliances to benefit from more-established channels of distribution, marketing, or brand reputation of bigger, better-known players. Companies might also consider cooperating with other firms by outsourcing the cost of non-core functions, freeing them to focus on key areas.

These challenges were selected as the theme of our 20th World Petroleum Congress which will take place in Doha, Qatar in December 2011. Taking the outcomes from the 19th WPC in Madrid a step further our Congress Programme Committee selected the theme of: Energy Solutions for All – Promoting Cooperation, Innovation and Investment.

We have taken several of the key issues that will be addressed under that heading at the Congress next year and asked senior industry representatives to share with us their views on the challenges and opportunities facing our industry. Please see for yourself what their contributions are in addressing Global Energy Solutions.
The previous World Petroleum Congress in Madrid in June 2008 provided us with an exhaustive picture of our industry, its achievements, as well as a range of solutions for the current and future challenges. We are not looking for short-term approaches but concentrating on the long-term sustainable future of our industry and the future energy transitions that we face.

With the focus on the future and what is required from a technological point of view, we often forget that we will need more people on the ground to do the required work. This is now becoming a real and pressing issue. With 50 per cent of the existing workforce about to retire in the next ten years, the oil and gas industry now faces a massive challenge to attract enough young people to the sector. Who will be replacing the expertise that is leaving the industry? Not only does the industry have to deal with its environmental and societal reputation, but it also has to face the large reduction in young people choosing sciences for their career. But without more scientists and engineers it cannot sustain the levels of operation needed and will not be able to deliver enough energy for the future. This growing skills gap may impede the industry’s very ability to operate, especially with respect to major exploration and production projects. This challenge is particularly significant in the context of the world’s rapidly growing demands for energy and calls for greater adherence to responsible social and environmental practices. It is crucial therefore to address the young generation directly and introduce them to the wide breadth of areas and activities that make up the petroleum sector. In keeping with WPC’s mission to promote the attraction and retention of young people for the petroleum industry, we started that process a few years ago.

Young people are looking to industry leaders for solutions to global energy challenges. This publication will take a step forward towards achieving greater understanding and a closer engagement between the generations.

In response to this challenge, the World Petroleum Council formed its youth policy, creating a Youth Committee, to bring a higher profile to the issue and form an alliance with young people themselves in order to find possible solutions to our challenges. We feel that it is important that young people are at the forefront of resolving the issues as they are the ones who will inherit this industry, and should be involved in crafting its future.

The number of the Youth Committee has steadily risen to now 20 representatives of the WPC’s National Committees active in its operations. Their first task was to prepare a programme of activities for young people at the 19th World Petroleum Congress in Madrid in 2008. From a central Youth Stand they acted a gathering point for the young attendees of the Congress and offered a host of information about the industry and the role of young people in it. A highlight was the special round table with industry leaders to discuss the question of “Does the industry need an image makeover?” The success of the activities at the Madrid Congress has inspired the team and they look forward to offering an even more extensive programme at the 20th World Petroleum Congress in Doha next year.

In October 2004 China hosted the 1st WPC Youth Forum in Beijing, with over 500 young delegates focusing on ‘Youth and Innovation – the Future of the Petroleum Industry’. It played an important role in implementing the WPC’s strategy to attract more young people to WPC activities and the petroleum industry. Last year it was the turn of the French National Committee who managed to gather 1200 young attendees in Paris where they hosted our 2nd WPC Youth Forum under the theme of ‘Energise Your Future’. The Youth Committee was given full responsibility for the programme of the event. As part of their innovative approach to presenting the challenges and opportunities facing the oil and gas industry in the future, an online network was set up to start the discussions amongst young people from around the world and to prepare questions for the high-level industry leadership at the Youth Forum. They took full advantage of this unique opportunity to present their issues and concerns to the decision makers and engaged in an interactive exchange of ideas and solutions for our future.

In November this year India plays host to our next Youth Forum. We are inviting students and young people from the industry to participate and showcase their issues and knowledge at the event held alongside the well-established Petrotech conference in Delhi in November. The results and outcomes will then find their way to Doha and the 20th World Petroleum Congress just over a year later, where youth will be an important and integrated partner in the proceedings.

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We need to move forward to engage young people in our industry and I call on everyone in the petroleum sector to give their full support to this endeavour and to mobilise their students and young professionals in order to energise all our future!
OPEC at Fifty: an ongoing commitment to market stability

BY ABDALLA SALEH EL-BADRI
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Since its founding fifty years ago on September 14, 1960, OPEC has seen growing recognition of the positive role it plays in the international oil market. Through its ongoing commitment to ensuring market stability, OPEC has made enormous strides during its long history to cooperate with other international actors for the benefit of producers and consumers alike.

OPEC has gained this recognition by consistently trying to ensure a regular supply of petroleum to the market in a timely and efficient manner. This is the fulfilment of one of the Organisation’s objectives as enshrined in its Statute. Much of this is a consequence of the emphasis OPEC has placed over the years on research and monitoring activities. Based on the work done at the Secretariat, OPEC has developed a sophisticated understanding of both the international oil industry and global markets. This has enhanced our ability to respond to events.

Growth Years

OPEC’s 50th anniversary slogan, ‘Supporting Stability, Fuelling Prosperity’, summarises the path that OPEC has taken for five decades. If one considers the growth in reserves, the increased production and the ongoing investment commitments in Member Countries, then OPEC’s role as a central actor in providing market stability is indisputable.

But in celebrating OPEC’s Golden Jubilee, it is easy to forget the long road we have travelled. We have gone from an Organisation with five Founding Members – the Islamic Republic of Iran, Iraq, Kuwait, Saudi Arabia and Venezuela – to one with twelve Member Countries. On average, these countries supply more than a third of world oil production.

We have also seen joint reserves grow in the past fifty years from a total of around 200 billion barrels to one trillion barrels. More than three-quarters of the world’s proven recoverable crude oil reserves are now found in OPEC Member Countries. Additionally, total daily production in this time has grown to around 29 million barrels per day (b/d), with overall production capacity reaching more than 35.2 million b/d in 2009.

Part of this growth is of course simply the result of increased membership (with the Organisation going from five to twelve members). But even if we limit ourselves to the five Founding Members, the growth in reserves and production from 1960 to 2010 has been nothing short of impressive. Increased collaboration between National Oil Companies and oil majors, enhanced cooperation between producers and consumers, and significant advances in technology have all helped towards the discovery of new oil fields, increased access to frontier fields and improved recovery rates. But in order to turn all these reserves into products for the market, significant investments in both the upstream and the downstream are required. But such investments depend on certainty – and, more importantly, what OPEC likes to call energy security.

Energy Security is a Two-Way Street

If our history is to provide a guide to the future, then it is clear that OPEC will continue to play an essential role in supplying oil to the world – even as it faces ongoing challenges. Underlying many of these challenges is the constant need for energy security and, more specifically, security of demand. Without greater certainty in demand growth and future demand levels, investments in the development of future capacity are threatened. Without that confidence in additional demand for oil in the future, there will be few incentives to invest.

In the short term, one important source of uncertainty relates to economic conditions in the eurozone and the potential spill-over effects from the sovereign debt crisis. The recent global economic crisis has put a damper on economic growth around the world, negatively affecting oil demand levels.

But OPEC is also concerned about the possibility that the various economic stimulus packages that developed countries have put together may soon come to an end. This could negatively impact the overall recovery of the global economy. The potential negative impact of this on oil demand could be quite strong, especially if the expected economic growth doesn’t materialise or if the pace of recovery efforts is limited.

In the meantime, while the recovery of the global economy appears to be continuing, OPEC remains cautiously optimistic. It will continue to closely monitor the market. But it recognises that a lot of uncertainty remains.

In the longer term, a significant source of uncertainty has to do with the consequence of the new policies in developed countries that effectively end up discriminating against oil and other fossil fuels. While OPEC continues to assess the emerging policies and analyse all the available information, it has consistently been urging concerned countries to stop discriminating against oil. Despite these uncertainties regarding demand growth, as well as other concerns regarding spiralling production costs and a lack of skilled human resources, investments to expand upstream capacity are currently underway in OPEC Member Countries.

Last year, about 30 projects came on-stream in Member Countries. This resulted in 1.5 million b/d of net crude and liquids capacity. OPEC data indicates that for the next five years, the completion of an additional 140 projects will add about 12 million b/d of gross crude and liquids capacity. Thus, OPEC believes that current investments should be enough to satisfy demand for OPEC crude, even though our current spare capacity is over 6 million b/d.
OPEC Member Countries are also investing in expanding downstream capacity, both inside and outside Member Countries. For example, cumulative investment in downstream capacity in Member Countries until 2015 has been estimated at around US$40 billion.

This level of investment will help expand refining capacity to more than 10 million b/d. An additional US$25 billion are being invested abroad to add further capacity to the global refining system.

All of this demonstrates OPEC’s ongoing commitment to ensuring adequate production capacity. But the fact of the matter is that OPEC can only continue to play a role in supporting market stability if developed countries avoid subsidising coal and alternative forms of energy to the detriment of oil and petroleum products.

This is why OPEC encourages greater transparency between all stakeholders in the energy industry. It is especially supportive of the ongoing producer-consumer dialogue that takes place through the International Energy Forum. It is through such meetings that the Organisation strives for better dialogue with consumers in developed countries – in order to clearly assess the potential impact on oil demand of emerging energy policies. This is one of the surest ways to help improve oil demand forecasts, especially as they pertain to future demand levels.

The Importance of Dialogue
With all this in mind, it is important that OPEC continues participating in meetings and events where it can share insights and exchange views about energy market trends with other global energy stakeholders. Everyone needs to remember that energy is crucial for sustainable economic development, and human development, in each and every country of the world. For this, the world needs an energy market that is stable and predictable.

It is also important to remember that over the past fifty years, the world has been evolving towards greater interdependence and more integrated energy markets. If one considers the fact that the global economy lately has presented daunting challenges to everyone, then one cannot escape the conclusion that, perhaps more than ever before, people need to work together.

This theme was addressed at OPEC’s Third Summit of Heads of State meeting in Riyadh in 2007, which explicitly called for expanding existing and new avenues of cooperation with energy stakeholders. It is precisely with this spirit that OPEC is now endeavouring to enhance dialogue with many producing and consuming countries. It is through such collaborative, joint efforts that international actors like OPEC will continue to lead the way to a more secure, more stable world.

Heads of Delegations attending the first OPEC meeting: (clockwise) HE Fouad Rouhani, Iran; HE Dr Tala’at Al-Shaibani, Iraq; HE Dr Juan Pablo Pérez Alfonzo, Minister of Mines and Hydrocarbons, Venezuela; HE Ahmed Sayed Omar, Assistant to the Secretary of State, Ministry of Finance, Kuwait; HE Abdullah Al-Tariki, Minister of Petroleum, Saudi Arabia
The future of producer-consumer dialogue post-Cancun

BY DR NOÉ VAN HULST
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The producer-consumer dialogue is thriving and poised to make an even larger impact on global energy security. IEF12, held in Cancun, Mexico in March 2010, drew more than 100 delegations and illustrated the vibrant health of the dialogue today. Sixty-three Ministerial delegations joined 14 international organisations (including the World Petroleum Council) in a frank and open dialogue about the issues facing today’s producers and consumers of energy. Thirty-seven top level representatives from industry, including both international and national oil companies, also joined the dialogue in our most widely attended and successful IEBF to date. The growth from 2008’s IEF11 was plainly evident. Ministers, CEOs and international organisations are more committed than ever to making the dialogue through the International Energy Forum as fruitful as possible and thus help to create efficient and effective market conditions throughout energy sector.

In addition to being an inimitable venue for energy dialogue, the IEF Ministerial is an opportunity to take stock of the two years since the last Ministerial. One would be hard pressed to find a more turbulent and uncertain two-year period than that between 2008 and 2010. In oil markets, prices fluctuated between a high of nearly US$150 in July 2008 to a low in the US$30s by December 2008, although, prices have since recovered. Today, prices appear relatively stable but, as IEF Ministers wisely noted in Cancun, how long that relative stability will persist is unknown. Many of the causes of high energy market volatility, which the IEF explored, are still present and market turbulence remains a threat to investment, the development of renewables and general economic growth. Ministers in Cancun were committed to avoiding a return to the days of excessive volatility. They applauded the unique programme of cooperation agreed upon by the IEA, IEF and OPEC which will focus on enhancing data transparency and cover the linkages between physical and financial markets, energy market regulation and a shared analysis of future trends within energy.

The IEF, in cooperation with APEC, EUROSTAT, IEA, OLADE, OPEC and UNSD, continues to combat volatility with better, more complete and timely physical oil market-data through the Joint Oil Data Initiative (JODI). JODI collects monthly oil data from more than 90 countries and, as the developing world presents an increasingly larger share of global production and consumption, is crucial to understanding what is happening in markets today. Ministers were pleased to hear that the JODI model is being employed in the collection of monthly natural gas data but also called for further expansion of the Initiative into annual data on upstream and downstream capacities and expansion plans in oil and gas. With a gas market that is becoming increasingly globalised through growing LNG trade, JODI’s move into natural gas is particularly salient. Progress on this expansion will be discussed this November at the second IEF-IGU Ministerial Gas Forum, to be held in Doha with the support of the government of Qatar.

JODI is the IEF’s flagship programme on transparency but we, like Ministers, recognise that transparency should be pursued in every element of the energy market. Today, futures markets for energy serve as a significant price discovery function but the way in which those exchange-traded products interact with the physical market and the opaque over-the-counter, or OTC, market is less than clear. 2008 and 2009, and even the IEF12 itself, witnessed a lot of discussion about the role of ‘speculators’ in oil price determination but little about the component parts of what has become a dizzyingly complex global market. To shed some light on the darker corners of the financial and physical markets for oil, the IEF has joined with the IEA and OPEC to hold a workshop on the linkages between the physical and financial markets for oil in November of this year. The workshop will bring together financial institutions, reporting agencies, regulators and commercial market participants to uncover how the relationship between the two markets has changed, why those changes have occurred and what may be in store for the relationship as each market matures.

A successful producer-consumer dialogue can achieve greater transparency of historical and future market data and greater predictability of energy policies

In combination with that workshop in November, the IEF, IEA and OPEC will also be holding a round table for energy market regulators. The outcry over ‘excessive speculation’ in 2008 and 2009 joined a call for greater market regulation but regulators are only capable of enforcing law within their own jurisdictions. And, unfortunately, arbitrageurs have a long history of moving to the least regulated markets. With regulatory proposals at varying stages of development in major markets, a degree of timely cooperation between regulators around the world is necessary if implementation is to have the desired effect. The IEF hopes to aid in that cooperation and, with the round table, examine the current and potential effects of regulation that have been enacted or proposed. Markets are truly international and if regulators intend to have a significant impact on markets, coordination will be necessary.

Another issue consistently raised by Ministers and market analysts is the discrepancy between the energy outlooks of organisations and companies. The difference in projected supply and demand in the short, medium and long term is another uncertainty that must be accounted for by industry.
To reduce some of that uncertainty, the IEF, in conjunction with the IEA and OPEC, will be hosting the first Annual Symposium on Energy Outlooks in January 2011 at its offices in Riyadh. We hope to bring more clarity to some of the diverging assumptions made in these outlooks and explain more clearly to the outside world and the markets what the key factors are that explain the differences in the future outlooks.

As mentioned above, the interdependency of today’s market is inescapable. Ministers at both IEF12 and IEBF4 noted the increasingly close working quarters that a more globalised market demands. As a result, the relationship between IOCs and their national hosts must be fortified. Success in today’s economic environment is determined by one’s willingness to engage partners with due respect for their strengths, weaknesses and respective roles in the project at hand. Equal footing and respect is vital to effective cooperation and long-term partnerships but both companies and countries were clear – their roles are different and should, for the most part, remain so. In Cancun, the work of the IEF in the realm of NOC-IOC cooperation was welcomed by Ministers and, in an endorsement of the event itself, many expressed interest in sending delegations to the next IEF forum on NOC-IOC cooperation, to be held in Paris and hosted by Total in the Spring of 2011. Participants at that event will attempt to distil from their experiences a written set of IEF general principles or guidelines for mutually beneficial and effective NOC-IOC cooperation, as a possible concrete tool to facilitate this cooperation.

Moving to issues that are of more social concern, Ministers in Cancun emphasised the need for sustainability, both in the production and consumption of energy. Energy poverty featured prominently on the agenda of the event itself but also in the comments made by Ministers. Among IEF countries are many that suffer from severe energy poverty and the issue is of paramount importance to them. Consequently, as was advocated at the IEF Symposium on Energy Poverty in December 2009, some suggested that a reduction in energy poverty should be added as the 9th Millennium Development Goal. Ministers can be assured that energy poverty will remain high on the IEF’s agenda.

Efficiency is another component of sustainability that received a great deal of attention at IEF12. Efficiency, of course, has two sides – efficiency in production and efficiency in consumption. In production, Ministers supported the findings of the IEF’s symposium on CCS, held in Beijing in September 2009, and anticipated even greater results from that meeting’s follow-up, held in Algiers in June 2010. Participants gathered in Beijing noted the ‘double-win’ that CO₂-EOR offers and the...
wider lessons that can be gleaned from its application in oil production. Of course, CCS has a long road ahead towards large scale commercialisation but the foundation for best-practice sharing, international cooperation that enables the technologies in use in CCS and innovative methods to develop and deploy the technology must be forged today. CCS development is a vital component of a low-emissions energy future and the IEF hopes to hasten the commercialisation of the technology so that our simultaneous goals of energy security and climate responsibility can be met.

Of course, energy efficiency does not end at the point of production. Energy efficiency has been, and will be for some time, the low hanging fruit of carbon mitigation and energy security. We must do more with less. Efficiency will never carry the sex appeal of renewable energy but its potential to drive down emissions, especially in the short and medium term, outweighs that of any other technology. Energy efficiency programmes have been most active in developed economies which have stronger price incentives and are better equipped, financially and otherwise, to implement them. But there is great potential in developing economies to build in efficiency as their infrastructure systems grow and their consumption rises. The future of demand growth is in the developing world and the window to fully integrate efficiency measures into their development is closing fast. Naturally, this includes oil- and gas-producing countries as well, where domestic oil and gas consumption has been increasing at more than twice the global growth rate in the past ten years alone, thus potentially threatening future export growth. With this in mind, the IEF, in cooperation with the government of Japan, will be hosting a symposium on Energy Efficiency in the Developing World in 2011. The symposium will bring together efficiency experts from around the world to explore the lessons learned in the developed world, examine the programmes that would work best in developing countries, and inform governments on the best means to build efficiency incentives into their growing economies.

IEF12 took clear advantage of the International Energy Forum’s greatest strengths – its role as a neutral facilitator of dialogue and the convening power of the world’s most inclusive energy organisation. The opportunity to meet, debate and explore issues of common concern was not lost on any of IEF12’s participants. But there was more to their participation than that discussed in Cancun. Sixty-six countries, including all the major energy players declared their commitment to the future of the IEF and the global energy dialogue by approving a landmark document in the organisation’s history, the Cancun Declaration. The Cancun Declaration established a solid foundation for the future of the global energy dialogue. The Declaration set a path forward for the IEF based on its vital informality, its dedication to honest and respectful dialogue, and its contribution to global energy security through the provision of balanced research and valuable energy market data. The 66 countries recognise that today’s energy sector is highly interdependent and success, both today and in the future, will require open lines of communication and stronger cooperation among its players.

There is great potential in developing economies to build in efficiency as their infrastructure systems grow and their consumption rises

Their commitment to the IEF is indicative of the faith they have in the institution, but also of the broad acknowledgement among the world’s energy ministries that complex global problems in today’s interdependent world require an intensified and productive global producer-consumer dialogue. And with the Cancun Declaration the IEF has begun the process of drafting an IEF Charter for its future which needs to be completed and approved in a separate IEF Ministerial Meeting before March 2011 in Riyadh. As the dialogue matures, we look forward to engaging with every element of the energy industry as we believe that focus, inclusivity and informality are the most powerful factors of a productive dialogue. A successful producer-consumer dialogue can achieve greater transparency of historical and future market data and greater predictability of energy policies, thus lowering transaction costs and helping to create efficient and effective market conditions. We look forward to a very busy programme of work over the next two years and to delivering concrete results in improving investment, transparency and sustainability in the oil and gas sector on the way to IEF13, to be held in Kuwait in 2012.
Given to the identification, development and management of resources. With ‘Borderless Energy’ adding an element of present day nations depends heavily on their management of their resources, including energy. Similarly, the stability of political paradigms is undoubtedly, ‘Energy Security’. Globally, the demands of a burgeoning population and rapidly growing economies are putting a strain on finite energy resources. Therefore, it is imperative to tap all the resources that will enable the energy sector to achieve its goal of improving the life of mankind. Such continuous pressure has compelled the industry to require greater contributions in terms of financial resources and technologies. But, most importantly, a new breed of technically-qualified and industry-orientated workers is required – these young, creative minds can then use their talents to produce positive business results. In the current climate, the young must seriously think about what the future holds for them in terms of energy security and what they can do about it.

In the last week of March 2010, student teams from six major academic institutions focusing on energy-related studies met at The University of Petroleum and Energy Studies, in Dehradun, India and presented their thoughts on Global Energy Equilibrium. It gave the author an opportunity to gain an insight into the thought processes of a generation that has to focus its energy on exploration, utilising existing resources and finding alternatives – all this, of course, within acceptable economic and environmental considerations.

It is not surprising that most of their presentations focused on an optimal energy mix with the main emphasis on local energy resources. This is understandable on two counts:

1) The concept of borderless energy can remain only that – ‘a concept’ – on paper. Wars have been fought to redraw the boundary between nations with the sole aim of garnering maximum oil reserves. With the decisive role played by ‘petro dollars’ in world economics, the redistribution of resources is mainly guided by the socio-political relationship between nations. Hence, no nation would like to depend completely on another for its energy needs, for it would leave it vulnerable to political ransoms.

2) Ancient civilisations endured by being self-sufficient in their resources, including energy. Similarly, the stability of present day nations depends heavily on their management of resources. With ‘Borderless Energy’ adding an element of insecurity to the scheme of things, emphasis, by default, is given to the identification, development and management of resources, locally.

An example of the shifting energy mix, predominantly polarising towards local energy resources can be seen from the statistics of India’s energy mix. Currently, India’s Primary energy mix is: Coal 53 per cent; Oil 33 per cent; Gas 9 per cent; Nuclear 1 per cent; and Others (Hydroelectric & Renewable) 2.63 per cent. In about 10 years’ time, that is by 2020, the energy mix estimated for India is: Coal 30 per cent; Oil 25 per cent; Gas 16 per cent; Nuclear 5 per cent; and Others 24 per cent. It can be observed that coal will still dominate the energy mix because of its local availability. However, the interesting development in 2020, would be the increase in the percentages of Gas, Nuclear and Others, clearly indicating the focus on local availability.

Increasing the skills capacity of local youth is essential if the local energy resource is to be managed and developed. India, the fastest-growing economy along with China, is not only focusing its efforts on acquiring exploratory blocks and producing assets around the world but is also taking steps to develop local skills. The greatest asset that India has is its Youth, with 66 per cent of its population under 35 years of age. The average age of the population in 2020 is expected to be 29 years. This Youth percentage in the population is termed by experts as a ‘Demographic Dividend’. However, this youth percentage can only be a ‘Demographic Dividend’ if this part of the population is adequately and appropriately skilled. For this, (i) Education, (ii) Association with Industry and (iii) Awareness of Technology Development through global networking are all critical elements.

Skills development of the young, through education is a vital factor and one taken very seriously by responsible governments. The number of university-level institutions in India at the beginning of the decade just after it became independent in 1950, was 32. There were just 695 colleges affiliated to these universities with a combined student enrolment of 173,696. By the turn of this century the number of universities in India had increased to 256, with 12,342 colleges and 8,399,443 students enrolled. Approximately 40 per cent of those who enrolled were female students, thus indicating a positive development in a traditionally conservative society.

Within the petroleum industry, Energy Security has become an important factor in formulating the country’s economic strategy. During the past few decades there has been a strong focus on energy studies, with premier institutes dealing specifically with the Petroleum Exploration and Production (E&P) Industry being established in India. It is pleasing to note that there has been a very enthusiastic response from students.

Skills development, in a strict sense, is not limited to education alone. The spurt of educational institutions has given the required academic thrust, and, depending on the socio-economic and industrial requirement of the country, has varied the subjects of interest from time to time. Medicine

Youth, local content and skills capacity building

BY DINESH KUMAR PANDE,
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and Mechanical Engineering have always been popular, whilst Information Technology (IT) has given rise to a scramble for subjects such as Electronics & Communication Engineering and Computer Science. India, with its strong English language base and its partiality towards Mathematics has attained a dominant position in the IT/Software industry. So, it can be reasonably stated that industry requirement is the main catalyst in inspiring youth to sharpen its skills in the desired subject. Thus, the underlying fact in local skills development is that, although academia is in the forefront, the contribution of the industry is essential in giving the right kind of impetus to the effort. The involvement of industry is in its own interest as it needs skilled manpower – all the more critical in heavily technology-dependent industries like petroleum, both upstream and downstream.

Most of the oil industries are facing the problem of an ageing workforce; the average age of people in the oil industry is almost 50. There has been talk of manpower shortages, especially in the E&P industry, so it is in the industry’s interest to encourage skills development. The introduction of young, fresh talent can only help to boost exploration. Under the concept of an ‘Industry-Academia’ interface, various steps are being taken to encourage industry awareness. As well as the frequent visits of professionals as faculty in many industries, in India E&P companies establish ‘Chairs’ in various Universities as part of the Industry-Academia interface. Student chapters of various professional associations are also opened in educational institutions where students get to meet industry experts and interact with them. This will be helpful in inducing research orientation, both fundamental and applied, within the industry. Academia, for its part has to ready itself for the challenge of meeting the growing expectations of the industry. The number of institutions with energy-related subjects as a core discipline is to be increased and the curriculum is to be tailored and standardised according to industry requirements. Academia is also expected to take up R&D projects for addressing exploration, reservoir and drilling problems, whether conventional or unconventional resources. Industry is required to come forward to provide assistance in designing course contents and providing industry-orientated practical education.

Apart from education and industry association, the third important component of skills development is exposure to global developments and techniques. Encouraging the participation of students and young professionals in international conferences is one way of granting them exposure. For example, the WPC Youth Forum has become a platform where the common interests and concerns of energy issues at local levels are shared, discussed and deliberated by the young who are endeavouring to find globally acceptable solutions. The youth of developed countries can interact with young people from under-developed countries resulting in orientating their thought processes, not only to explore and exploit existing energy reserves, but also to find alternatives to dwindling resources. Recognising the importance of youth networking in their skills development, the 3rd WPC Youth Conference is being held in conjunction with The Petrotech 2010 Conference in India later this year. The Honourable Prime Minister of India, Dr Manmohan Singh will inaugurate the conference, underlining the Indian government’s view on the importance of global networking on energy-related matters.

Finally, on local skills development addresses to students, the following elements must be prioritised:
1) To spread awareness of environmentally-acceptable, effective, energy solutions
2) To conserve energy by focusing on energy-efficient systems
3) To advocate new technology and focus on research for providing viable alternative energy security
4) To apprise youth of developing countries the present state of growth in the energy sector and additionally, to make the youth of advanced countries aware of their responsibilities towards their counterparts in developing countries
5) To encourage young women to join us in our bid to provide global energy security and improve the gender ratio in our sector.

The 3rd WPC Petrotech 2010 Youth Forum is an effort by the World Petroleum Council to focus on the above, and, with the involvement of senior government functionaries, is expected to generate interest amongst junior staff in the energy industry. The author, as Vice-President (Youth & Gender) of WPC is expected to invite the world’s young to the forum.

Further details of the programme are available on the website: www.fueltheyouth.com
The end of national oil companies

BY MILTON COSTA FILHO, GENERAL MANAGER AND PEDRO MARTÍNEZ LARA, TECHNICAL ASSISTANT, PETROBRAS MEXICO

It is a well-known fact that National Oil Companies (NOCs) have become dominant actors in the oil and gas industry. Of the world’s 50 top oil companies, 31 are state-owned; 19 fully, eight majority and four partially, according to the 2010 Petroleum Intelligence Weekly Rank. NOCs’ growing influence proceeds not only from their controlling most of the world’s oil and gas reserves and production, but also from their increasing financial strength. The PFC Energy list of the Top 50 Largest Listed Energy Firms shows that integrated NOCs presently account for 32 per cent of the total combined value of the 50 largest public integrated energy companies – whereas in 2001, they represented a meagre 1 per cent.

Widely diverse as they are, many NOCs have undoubtedly attained the financial, technological and managerial level of development required to engage in large, complex projects. Closing the gap between their means and those of International Oil Companies (IOCs) has allowed NOCs to compete successfully with the latter in both their home countries and abroad.

Nowadays NOCs play an important role as investors in the sector. According to the GlobalData report Outlook 2010 – Global Oil and Gas Capital Expenditure, published in 2009, and in spite of the economic downturn, listed NOCs invested US$323 billion to develop their activities at home and abroad. This figure is expected to reach US$375 billion in 2010. According to Ernst & Young’s analysis, Investing for the Upturn, by 2015, based on current estimates, the largest NOCs will have invested close to US$600 billion.

Likewise, NOCs are expected to contribute a sizeable share of the new production capacity in the coming decade. According to PFC Energy, a significant amount of the crude output will come from the so-called BRINK countries (Brazil, Russia, Iraq, Nigeria and Kazakhstan) that are estimated to contribute a 3.5 million barrel per day increase by 2015.

The challenge and the context

Apart from having the responsibility of exploiting reserves of hydrocarbons and, in many cases, guaranteeing energy security, NOCs also play a significant role in contributing to the growth of their home countries by fostering economic prosperity. They contribute strongly to the expansion of local suppliers and resources, the implementation of social programmes and the deployment of advanced technologies and know-how.

Without a doubt, NOCs have transformed themselves into the most important actors in the energy sector. They have the power and legitimacy required to perform such a role. Still, there is a crucial question to be answered, namely: how can NOCs help to address one of the biggest problems facing humanity?

Can NOCs contribute to guaranteeing a sustainable, reliable and affordable supply of energy to our planet?

This is, in fact, a most urgent matter to be dealt with and a good way of depicting the seriousness of the situation is the analysis of the five mega-trends recognised by the UN in its 2009 General Assembly as a global reality that requires a global response: population growth, urbanisation, migration and food, climate change and water and energy insecurity. All five trends are strikingly associated with the way we produce, distribute and consume energy. Therefore, they have a direct impact in the complexity of the environment in which NOCs operate.

The world population is expected to grow at an average annual rate of 1 per cent, from 6.5 billion in 2007 to 8.7 billion in 2030 (UNPD 2009). Besides which, populations are most likely going to concentrate in urban areas. Projections indicate that nine cities will be housing more than 20 million people by 2020 and 70 per cent of the world’s population will be living in urban areas by 2050. Such growth poses a most serious challenge to an energy sector that has been unable to provide enough services to the present world population. In fact, current energy poverty affects 2.5 billion people who have no access to modern fuels for cooking and heating, and 1.5 billion who have to do without electricity, a situation that inhibits social, human and economic development. Demographics clearly affect the size and pattern of energy demand.

In addition to population growth, rising income and dietary changes are increasing demand for food. According to the Food and Agriculture Organisation (FAO), food production should increase by 70 per cent to feed a larger, richer, and more urban population, alongside improvements in its distribution to reduce the amount of people suffering from hunger – there are over a billion people in such a condition. The current food system relies heavily on huge amounts of fossil fuels, from planting, irrigation, feeding and harvesting, through to processing, distribution and packaging but, at the same time, it is one of the greatest producers of greenhouse gases (GHGs). Ironically, one of the serious risks of the food industry is global warming, with its environmental threats to agriculture, many of which are caused by the current agriculture pattern itself.

Water resources are already under considerable pressure. Currently, apart from the huge amount of people who are threatened by water shortages, there are 1.4 billion without access to safe drinking water and 2.5 billion who lack basic sanitation (WHO, 2007). Large amounts of energy are required to provide water for people’s basic needs but, contradictorily, a huge amount of water is required for energy generation.

According to the IEA Referenced Scenario, primary energy demand will grow 1.5 per cent annually between 2007 and 2030, which means an overall increase of 40 per cent.
Although all sources of energy will grow in this period, fossil fuels will continue to be the dominant source of primary energy worldwide. Their share in the energy matrix is expected to fall marginally from 81 to 80 per cent. In 2030, oil will remain the single largest fuel with a share of 30 per cent of the fuel mix, coal being the second, with 29 per cent. Renewable energies are the fastest growing energy source but, coming from a small base, their share will not exceed 2 per cent.

**National Oil Companies should move away from their historical oil and gas business into a wider portfolio involving renewables and other sources of energy**

If there is no significant change in the patterns of consumption and the way energy is produced, energy-related CO₂ emissions will increase, driving a rise in the global temperature that could reach up to 6°C (World Energy Outlook, 2008). The Intergovernmental Panel on Climate Change (IPCC) states that some of the predicted effects of an increase in global temperature over 2°C include extreme heat and drought, sea level rises and a decrease in water and food supply. For each 4°C of warming, world GDP could experience a reduction of between 1 and 5 per cent. To avoid irreversible changes in the global climate, GHG concentration should be limited to 450 parts per million (ppm) of CO₂ – equivalent.

**Energy is at the root of many problems and must therefore be at the heart of the solution**

In the face of this reality, it is clear that the current energy trends are not sustainable. We are going against the sustainability concept by looking only after present needs while leaving problems and their solutions to future generations. A change in our current pattern of energy consumption is of crucial importance to sustainable development. Cheap energy, subsidies, easy access to credit and globalisation encourage excessive consumption. Both consumers and producers, represented by international country organisations are failing to come up with global solutions for these important issues. The lack of success of the Kyoto Protocol and the failure to arrive at a substitute treaty at the COP 15 Conference in Copenhagen last December, clearly illustrate the level of fragmentation in which the global energy sector has to perform.

In order to shift the current trends in energy consumption into a more sustainable energy industry we need a new, global energy architecture where all countries are committed to the change. Such an institutional framework would allow for a better coordination of efforts towards balancing energy sources, developing new technologies, mitigating effects on the environment, alleviating energy poverty and promoting the rational, efficient use of energy along the lines of initiatives like that of the International Energy Forum (IEF).

Given the urgency of the situation, some immediate actions aimed at paving the way for a sustainable energy future cannot wait for the consolidation of a new global energy architecture. Firstly, it is imperative to shift into a more rational and efficient use of energy, capable of producing considerable immediate benefits. According to McKinsey Global Institute, just by using or deploying known technologies the world could save up to 63 million barrels of oil equivalent per day out of the projected daily consumption for 2020. In parallel, there is a need to accelerate the development of new energy sources in order to achieve a balanced sustainable world energy matrix in the long term.

Success in implementing the two above mentioned actions requires huge amount of resources. According to the IEA, reaching the 450 ppm Scenario will require an investment of US$36.1 trillion in energy-supply infrastructure for the period 2010-2030. Investing such a huge amount of money represents a grand challenge for the sector. However, the two recent financial and economic crises (2008-09 and 2010) have shown the international community is able to coordinate efforts to tackle a common problem, provided there is enough political will.

**New vision**

Given the depicted circumstances, the actors that currently fulfil the conditions to play a leading role are the NOCs. Supported by their governments, NOCs have the legitimacy and the power to implement the necessary courses of action: promoting a rational, efficient use of energy and developing a balanced, sustainable world energy matrix. In so doing, NOCs become empowered agents in the promotion of a sustainable energy future. Consequently NOCs should move away from their historical oil and gas business into a wider portfolio involving renewables and other sources of energy: solar, eolic, geothermal, nuclear, biomass and waste, tide and wave, and hydro, among others.

The above entails a complete change in the vision and mission of NOCs, as well as in their strategies and business models. NOCs should conceive themselves as actual energy companies so as to make a decisive contribution to attaining a sustainable energy future.

The moves that some NOCs are already making in that direction, transforming themselves into energy companies, would seem to indicate that we are on the verge of witnessing the end of the era of National Oil Companies and the rise of the new era of National Energy Companies – NECs.
In 2011, the World Petroleum Congress is taking place in the Middle East for the very first time in its 74-year history. At ExxonMobil, we are proud to support Qatar as the event’s first regional host. After more than fifteen years of partnership with the State of Qatar, it is an honour to play a continuing role in Qatar’s impressive economic growth. Under the leadership of His Highness the Emir, Qatar has become an example of what can be achieved through cooperation, innovation and investment. Thanks to the Emir’s long-term vision, the State of Qatar has laid a strong foundation for future generations.

Seventy-four years may be too broad a frame of reference in many industries, but given the technical, financial and market challenges that characterise the energy industry, it can measure the lifespan of a single project. When the World Petroleum Council was founded in 1933, the world was in the midst of the worst economic crisis of its generation. In May of that year, a surplus of East Texas crude caused prices to fall below the cost of production – to just 4 cents a barrel. This occurred despite the fact that, just 10 years earlier, warnings had been issued about the threat of rapidly depleting US oil reserves.

Today, our industry is dealing with similar challenges. The global economic downturn has temporarily reduced energy demand. Regulators and governments have questioned whether it is possible to meet long-term global energy demand while at the same time protecting the environment. As was the case in the 1920s and again in the 1970s, there are those who believe that our children will inherit a world with insufficient energy supplies. As a result, many in our industry are re-evaluating their near-term business plans. Many outside our industry are suggesting it is a time to lose focus, but rather an opportunity to strengthen and prepare for the future.

The visionaries who founded the World Energy Council in 1933 did not know the specific challenges our industry would face in the century to follow. To a certain extent, nor do we. What we do know, however, is that the key to thriving in challenging times is to maintain a long-term view and focus on the fundamentals. History tells us that now is not the time to lose focus, but rather an opportunity to strengthen and prepare for the future.

Over the next 20 years, the International Energy Agency and many others estimate that the world’s total energy demand will increase by almost 35 per cent, as compared to 2005. Today, approximately 2.5 billion (bn) people around the world live without access to modern cooking or heating fuels. Increasing energy supplies in the years ahead will be critical to ensuring that these populations have the opportunity to achieve higher standards of living.

With this outlook in mind, our industry must re-affirm our commitment to the long term by making disciplined investments to increase energy supplies, by advancing technologies to support future growth, and by developing people and organisational capabilities. We must do so while maintaining an unwavering focus on safety and protection of the environment. The energy industry is truly a commodity business. As such, we are subject to the ups and downs of the marketplace. We expect it, we plan for it, and we have experienced it before. We know firsthand that the energy we use today is the product of investment decisions and technical work that were undertaken decades ago. Similarly, the energy we use tomorrow will be the result of decisions that we make today.

Within ExxonMobil, we are demonstrating our commitment to a long-term focus by pursuing plans to invest US$25-$30 bn annually on energy projects over the next five years. These are record investment levels for us. We are able to confidently pursue these plans based on our long-term view of industry fundamentals and our commitment to financial discipline, in good times and bad. Our investment comes in the context of broader necessary expenditures. The International Energy Agency predicts that the total investment needed in the world’s energy sector from 2007-30 is about US$26 trillion. Spending devoted to oil and gas is estimated to be about 45 per cent of the total or close to US$500 bn per year alone.

However, the investment needed to meet long-term global demand cannot occur without the right policies and leaders who shape them. In order to feed economic growth, the world will need leaders willing to commit to stable fiscal and regulatory frameworks that will encourage long-term energy investments. We will also need policymakers with the conviction to ensure...
that sound energy policies are implemented efficiently and remain stable over time.

We know that with time, stronger economic growth will return and energy demand will rise. It is important that we collectively continue a long-term approach by investing capital and human ingenuity into developing future energy supplies.

Meeting the energy demand challenge is closely linked to the environmental challenge. Because we want to ensure that today’s progress does not come at the expense of future generations, we need to manage risks to our climate and environment. Protecting the environment while meeting demand will require the industry to develop all sources of energy – from traditional hydrocarbons to wind, solar and biofuels – when and where they are economically competitive. The best way for us to meet future demand while protecting the environment is to continue to research, develop and implement new technologies.

The energy industry is one of the most technologically-advanced industries in the world. Supplying the world’s energy requires a vast, complex infrastructure. New supplies of energy are increasingly being discovered in extreme conditions – originating deep below the ocean’s surface, the arctic reaches of the globe, or drawn from layers of rock once thought unviable. Because this infrastructure can take decades to develop, the time to bolster our commitment to technology is now. Technology holds the key to integrated solutions that address the energy supply, security, efficiency and environmental goals we all share.

ExxonMobil is committed to technology. Over the past five years, we have invested more than US$3.7 bn in research and development. Worldwide, we employ more than 16,000 engineers and scientists working to develop energy solutions. They are focused on increasing energy efficiency in the short term, advancing proven emissions-reducing technologies in the medium term, and developing breakthrough, game-changing technologies in the long term.

Technologies to increase energy efficiency are a critical piece of the solution. Increased efficiency is effectively the single greatest ‘new supply’ of energy available to us today. We estimate that by 2030, the amount of energy ‘saved’ through future efficiency gains will be equivalent to more than 100 million barrels of oil a day. The development and deployment of new technologies can also help us bring greater amounts of energy supplies to market, while reducing environmental impacts. One particularly promising technology that could mitigate the environmental impact of energy consumption is carbon capture and storage, or CCS. When the three phases of CCS – capture, transportation, and sequestration – are fully integrated into power plants and industrial facilities, we can achieve substantial emission reductions.

Advancements in CCS have the potential to make an impact on a global scale. However, current technologies to separate and capture CO₂ are cumbersome and expensive. Our scientists and engineers have spent more than three decades researching, developing, and applying technologies to make CCS more viable. Their progress is apparent through the recent introduction of ExxonMobil’s CFZ™ technology, a fundamentally different approach to removing CO₂ from natural gas that may make CCS more efficient and affordable in reducing greenhouse gas emissions. We recently invested over US$100 million to demonstrate this technology at our LaBarge, Wyoming, USA gas processing and injection facility. Combined with other advances in technology, CFZ could become a viable option to make CCS a commercial reality.

As we advance new technologies such as CFZ, it is important to remember that energy solutions depend upon the combination of complex variables, such as size, scope, and cost. The industry is challenged to balance long-term, global thinking with the short-term, incremental advances necessary to move confidently in the right direction.

Just as we look back and reflect on the world at the time of the World Petroleum Council’s founding in 1933, future generations will look back on our time and will evaluate the decisions we made in the light of the challenges we faced. Future generations will depend upon our investment, innovation and cooperation to solve the dual challenge of satisfying energy demand while protecting the environment. Our future success in this challenge will be determined by how well industries, governments and people from all over the world work together to pursue a long-term approach to a brighter energy future.
The international oil industry has always been characterised by cyclical behaviour. In particular, there are clear political and contractual cycles. These arise because of the nature of the relationship between the owner of the oil under the ground and the operator whose role is to get the oil above ground and to market. The owner of the oil in virtually all legal systems outside of the United States is the government. In the United States it is the property of the landowner who in any case is often the federal or state government. The operators, for much of the history of the industry, have been the international oil companies (IOCs).

The basis of this relationship between government and IOC is the contract negotiated and signed before the process of exploration begins. There are a great variety of such contracts ranging from concessions where the government gives the IOC operational control and taxes the profits to various production-sharing agreements where the government and its national oil company (NOC) participates in the operations and takes a share of the output. However, whatever the nature of this contract, its prime function is to divide the economic rent from producing and selling crude oil. This is the difference between the full cost of production including an acceptable rate of return on investment and the market price at which the oil sells. This is large and not surprisingly, the subject of considerable haggling between the two parties. For example, in Saudi Arabia the full cost of producing a barrel is currently less than US$5 while market prices are over US$70 and in 2008 reached over US$147.

This agreement gives rise to the contractual cycle which comes out of something known as the “obsolescing bargain”. This concept, first identified by Ray Vernon at MIT in the 1960s although grand sounding is very simple. The terms of the contract are the outcome of the relative bargaining power of the two parties at the time of negotiations. This will be affected by many issues such as the competence of the negotiators, the attractiveness of the exploration acreage and the extent of competition among the IOCs to name but a few. However, once oil has been discovered and the investment sunk in developing the field, the bargaining power switches dramatically in favour of the government. This invariably results in demands by government to renegotiate the agreement to secure a greater share of the rent. Incidentally, this phenomenon is not something which is only associated with “dodgy governments” in “dark continents”. Among some of its most belligerent adherents have been the governments of UK, Norway and Canada.

Related to this contractual cycle is the political cycle of “resource nationalism”. There are many definitions of “resource nationalism”, especially given its recent resurgence in countries as diverse as Venezuela and Russia. The simplest version has two components – limiting the operations of IOCs and asserting greater national control over natural resource development. When the government lack capacity to find and develop its own oil, it depends upon the IOCs. However, the country over time increases its own capacity to manage its oil resources. The government therefore begins to demand greater control; a process that is reinforced by the operation of the “obsolescing bargain”. It then pushes out the IOC and often reduces production levels. If a number of producers follow suit, oil supplies are constrained and prices rise. Higher prices with correspondingly higher government revenues means governments are better able to do without the IOCs or indeed greater production. In effect “resource nationalism” becomes a self-feeding cycle. However, at some point the rising price produces a reduction in demand and an increase in supply from other sources. Prices fall and governments find themselves strapped for cash. Greater production is required and the IOCs are encouraged to re-enter. The higher production forces prices even lower increasing the imperative for governments to raise oil exports.

The recent oil spill in the Gulf of Mexico may restrict access to more deep-water acreage and production, and not just in the United States

The political and contractual cycles together go a long way to explain the history of the oil industry. When the large fields of the Middle East were first discovered in the middle of the Twentieth Century, the contract terms were extremely favourable to the IOCs. This reflected both the power of their home governments in terms of colonial control over the countries and the lack of negotiating capacity on the part of the producer governments. During the 1950s and 1960s, these governments, especially in the Middle East and North Africa, became more aggressive over changing the contract terms and developing the capacity to manage their own oil. This culminated in the nationalisations of the early 1970s when in most producing countries the governments took over the operating companies owned by the IOCs. This process was strongly reinforced by a more general nationalist drive which emerged from the post-colonial period and the advent of the “Third World”. It was also encouraged by the two oil price shocks of the 1970s which reduced the need for governments to increase output.

After the oil price collapse of 1986 which was triggered by lower oil demand and the rise of non-OPEC supplies, producer governments started to look again at getting the IOCs to come
and develop their oil resources. Contracts were negotiated and signed, and fields developed and produced. However, after the oil price collapse of 1998, as OPEC began to get its act together, oil prices began to rise. At the start of 2002 oil was US$20 a barrel, which rose inexorably to over US$140 by mid-2008. In such a world, the "obsolescing bargain" re-emerged. Many governments demanded a revision of the fiscal terms which determined the split of the oil rents. At the same time, there was a growing view among producer governments who believed prices would rise forever, that since “oil in the ground was worth more than money in the bank” the IOCs were no longer needed. At the same time, populist politics encouraged the exclusion of the IOCs. In Latin America it was perceived that the IOCs had produced “our oil and our minerals” and there had been no tangible benefit to the “wretched of the earth” despite the fact that IOCs had been paying large tax revenues to their governments which meant because many were kleptocracies, the fault lay there rather than with the IOCs. Thus “resource nationalism” was alive and flourishing, and the IOCs were being pushed away from prospective acreage.

The key is to remember the cyclical nature of these phenomena. While oil prices were rising as they had been since 2002 reaching a peak in July 2008, “resource nationalism was a luxury which producers can afford. However, the collapse in prices at the end of 2008 caused a number of producer governments to reconsider. Many began to think again about encouraging the IOCs to become involved in their upstream. This was true even when prices began to recover in 2009 and entered 2010 in the US$70 to US$80 per barrel range. However, there were several problems with these approaches. First, the obsolescing bargain experience during the ramp up of prices between 2002 and mid-2008 made many of the IOCs very suspicious of the terms of the contracts being offered. The IOCs perceived that any agreement on terms would not survive very long, especially if the oil market showed signs of further recovery. Second, because of the global economic recession and its impact on oil demand, the amount of excess capacity to produce crude oil was high with the International Energy Agency estimating it at over 6 million barrels per day in May of this year. Thus, IOCs are concerned that if they were to develop even greater crude producing capacity they would not be allowed to use it as OPEC sought to defend prices. Finally, in many cases, the terms on offer failed to provide a rate of return that would be attractive to the IOCs. In the absence of such attractive returns, the financial strategy adopted by the IOCs (value-based management) meant they preferred to return the funds to their shareholders.

All of this carries important implications for future oil markets. Oil demand growth will return as the global economy recovers from the recent global economic recession. Although it is now generally accepted that OECD oil demand has probably peaked, there is still appetite for more growth in Asia, the Middle East and Latin America. Oil supply also faces constraints. The recent oil spill in the Gulf of Mexico may restrict access to more deep-water acreage and production, and not just in the United States. In addition, many producer governments are reluctant to allow their NOCs to invest more partly because of existing over-capacity and partly because they are seen within the governments themselves as being high-cost and inefficient rent seekers. Together, all this points over the next five to ten years to an erosion of the spare capacity to produce crude. As the spare capacity falls the oil market becomes vulnerable to outages of oil supply triggered by geopolitical events. When an outage occurs in a tight oil market, the resulting supply crunch leads to price shocks. If this were to happen there is a danger that the oil importing governments will resort to the type of ill thought out energy policy responses which characterised so much of the 1970s. Before that happens, there needs to be a grown-up discussion of possible joined-up energy policy options. At the very least this should try and mute any tendency to knee-jerk policy responses which have been so ineffective but also so costly in the past.
The corporate responsibility to respect human rights

BY PROFESSOR JOHN RUGGIE
SPECIAL REPRESENTATIVE OF THE UN SECRETARY GENERAL FOR BUSINESS AND HUMAN RIGHTS

This article discusses my mandate as the Special Representative of the United Nations Secretary-General on the issue of human rights and transnational corporations and other business enterprises, focusing on two key issues relevant to business: the corporate responsibility to respect human rights and human rights due diligence.

Background

Business’ responsibilities for human rights began to be hotly contested in the 1990s, as a by-product of that decade’s wave of privatisation and off-shore production; the fact that extractive and infrastructure companies were operating in increasingly tough neighbourhoods where they faced challenges they had never encountered before; and because companies assumed that getting a legal licence to operate from a government, no matter how corrupt and unresponsive it was to local populations, also provided a social licence to operate – but communities increasingly started to push back.

My mandate had its origins in a divisive debate generated by the ‘Draft Norms on the Responsibilities of Transnational Corporations and Other Business Enterprises with Regard to Human Rights’, presented to the then-UN Commission on Human Rights (now the Human Rights Council) in 2004 by a subsidiary body. The ‘Draft Norms’ sought to impose on companies, directly under international law, essentially the same range of human rights duties that States have adopted for themselves – to respect, protect, promote, and fulfil human rights. The two sets of duties were separated only by the slippery distinction between States as primary and corporations as secondary duty bearers, and by the elastic concept of spheres of influence, within which companies were proposed to have those duties.

The corporate responsibility to respect human rights means to avoid infringing the rights of others, and addressing adverse impacts that may occur. It applies to all companies in all situations

Business was vehemently opposed to the Draft Norms, human rights advocacy groups strongly in favour. After considering the issue for a year, the Commission declined to adopt the text, declaring that it had no legal status and that no action should be taken on its basis.

Instead, in 2005, the Commission requested the UN Secretary-General to appoint a Special Representative to move beyond the stalemate. Kofi Annan appointed me to the post and Ban Ki-moon has continued the assignment.

The ‘Protect, Respect, Remedy’ Framework

After three years of global consultation and extensive research, in 2008 I proposed a policy framework for better managing business and human rights challenges, which the Human Rights Council unanimously endorsed. It rests on three pillars: the State duty to protect against human rights abuses by third parties, including business; the corporate responsibility to respect human rights; and access by victims to effective remedy.

The three pillars are distinct yet complementary. The State duty to protect and the corporate responsibility to respect exist independently of one another, and preventative measures differ from remedial ones. But all are intended to work together and reinforce one another as parts of a dynamic, interactive system. So, with the understanding that the corporate responsibility to respect human rights is but one component in a wider system of preventative and remedial measures, I will focus on it here.

The Corporate Responsibility to Respect

The term ‘responsibility’ to respect rather than ‘duty’ indicates that respecting rights is not an obligation current international human rights law generally imposes directly on companies, although elements may be reflected in domestic laws. At the international level it is a standard of expected conduct acknowledged in virtually every voluntary and soft-law instrument related to corporate responsibility, and now affirmed by the Council itself.

The corporate responsibility to respect human rights means to avoid infringing the rights of others, and addressing adverse impacts that may occur. It applies to all companies in all situations.

As the world’s largest business associations have written, it exists even if national laws are weak or absent.1 The scope of the responsibility to respect is defined by the actual and potential human rights impacts generated by a company’s own business activities and through its relationships with other parties – such as partners, entities in its value chain, and State agents. In addition, companies need to consider the country and local contexts of their operations for any particular challenges they may pose.

Because companies can affect virtually the entire spectrum of internationally-recognised rights, the corporate responsibility to respect applies to all such rights. Some rights will be more relevant than others in particular industries and circumstances. But situations change, so periodic assessments against that entire spectrum are necessary to ensure that no potential human rights issue is overlooked.

Companies will find an authoritative list of such rights in the
International Bill of Human Rights (consisting of the Universal Declaration of Human Rights and the main instruments through which it has been codified: the International Covenant on Civil and Political Rights and the International Covenant on Economic, Social and Cultural Rights), coupled with the International Labour Organisation’s core conventions. While these instruments are not directly binding on companies under international law, companies can and do infringe on the enjoyment of the rights that these instruments recognise. Moreover, those rights are the baseline benchmarks by which other social actors judge companies’ human rights practices.

Human Rights Due Diligence
How does a company avoid infringing on the rights of others, and address adverse impacts where they occur? By conducting human rights due diligence.

Human rights due diligence is a potential game-changer for companies: from ‘naming and shaming’ to ‘knowing and showing’. Naming and shaming is a response by external stakeholders to the failure of companies to respect human rights. Knowing and showing is the internalisation of that respect by companies.

Drawing on well-established practices for corporate due diligence and combining them with what is unique to human rights, I have laid out the basic parameters of human rights due diligence. Because this process is a means for companies to address their responsibility to respect human rights, it has to go beyond simply identifying and managing material risks to the business, to include the risks a company’s activities and relationships may pose to the rights of individuals and communities.

One size does not fit all: there are 80,000 multinational corporations in the world, 10 times as many subsidiaries and countless national firms, many of which are small- and medium-sized enterprises. My aim is to provide universally applicable guiding principles for companies to meet their responsibility to respect human rights, recognising that the tools and processes they employ necessarily will vary with circumstances.

In that spirit, human rights due diligence comprises four components: a statement of policy articulating the company’s commitment to respect human rights; ongoing assessment of actual and potential human rights impacts of company activities and relationships; integration of human rights throughout the business to ensure that efforts to meet the responsibility to respect aren’t undermined; and, tracking and reporting performance.

Company grievance mechanisms are also important: under the tracking and reporting component of due diligence they provide ongoing feedback that helps identify risks and avoid escalation of disputes; they can also provide remedy, a method of alternative dispute resolution.

Why Bother?
Some companies may wonder why they should undertake human rights due diligence. Doesn’t all this just add burdens on business? My answer is decidedly no, for three reasons.

I’ve already noted the first: due diligence can be a game-changer for companies. Knowing and showing is necessary for companies to demonstrate they respect human rights. If they don’t know, and can’t show, any claim of respecting human rights is just that – a claim, not a fact.

Second, human rights due diligence can help companies lower their risks, including the risk of legal non-compliance. For example, there are situations in which companies currently harm human rights and, at the same time, may be non-compliant with existing securities and corporate governance regulations. Why? Because they are not adequately monetising and aggregating stakeholder-related risks, and therefore are not disclosing and addressing them.

Such risks stem from community challenges and resistance to company operations, which often occur on environmental and human rights grounds. The evidence to date comes largely from the extractive and infrastructure sectors, especially where companies operate in conflict-affected or otherwise contested contexts. But such internal control and oversight gaps are likely to exist in other sectors as well.

Stakeholder-related risks to companies include delays
This is a lose-lose-lose proposition: human rights are adversely impacted, serious corporate value erosion occurs, and disclosure requirements as well as directors’ duties may be implicated. Human rights due diligence can avoid all three.

Third, conducting human rights due diligence could provide protection against mismanagement claims by shareholders. And in Alien Tort Statute and similar suits, proof that a company took every reasonable step to avoid involvement in alleged violations can only count in its favour.

Conclusion

I am pleased that the UN ‘Protect, Respect, Remedy’ Framework as a whole, and the human rights due diligence component specifically, have been well-received by all relevant stakeholders.

A number of countries have utilised the Framework in conducting policy assessments, ranging from Norway to the UK and South Africa. Several major global corporations are already realigning their due diligence processes based on the Framework. Civil society actors have employed the Framework in their analytical and advocacy work. Other UN Special Procedures have drawn on the Framework in their analysis of corporate issues, as has the UK government in findings under the OECD Guidelines.

From the outset of this mandate, I have stated that there is no silver bullet solution to solving the very complex challenges at the intersection of business and human rights. All social actors must learn to do many things differently to ensure that global business is sustainable. Those things must generate an interactive dynamic of cumulative progress – precisely what the UN ‘Protect, Respect, Remedy’ Framework is intended to help achieve.

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This article is adapted from Professor Ruggie’s keynote address, ‘Engaging Business: Addressing Respect for Human Rights’, at an event sponsored by the US Council for International Business, the US Chamber of Commerce, and the International Organisation of Employers, hosted by The Coca-Cola Company in Atlanta, 25 February 2010.


4. All materials related to Professor Ruggie’s mandate, including official reports, speeches, research, and commentary and submissions from others can be found at: http://www.business-humanrights.org/SpecialRepPortal/Home.
Technology is the main factor in the development of the oil industry. Historically, the industry has been and still is, one of the key providers of scientific and technological achievements; it is a powerful driver of scientific and technological progress, stimulating research that is necessary to solve the considerable challenges of hydrocarbon exploration, production and refining. This research is ever more essential due to the finite nature of oil and gas resources and the depletion of very large fields and easy-to-produce reserves.

The principal issue presently is the depletion of mature oil and gas basins and the shifting of production to poorly developed regions and the continental shelf. Potentially, there is enough oil in the world as cumulative production makes up only one-third of conventional oil resources; non-conventional oil resources, such as shale, heavy oil and bitumen (see Figures 1 and 2) account for approximately as much again. The production of these potential resources is conditional on the development of the relevant technology to extract them, and the peak of global oil production could now be put off for several decades due to improving oil recovery and developing resources, the requisite expertise for which was previously not available. In addition, energy-saving technologies and the efficient use of resources are significant factors in reducing energy consumption.

Russia: the new leader in the development of oil and gas technologies

Being one of the richest countries in energy resources (see Figure 3), the current and future development of the Russian oil and gas complex is dependent upon the advancement and modernisation of its technologies.

Oil production in Russia (see Figure 4) is mainly based on the reserves prepared for production during the Soviet period and on a favourable global oil market. The successful development of the Russian oil industry has helped stabilise the Russian economy and ensure its growth.

Russia’s scientists were innovators in the field of world petroleum science and were responsible for many technological breakthroughs in oil production and refining. Unfortunately, since the 1980s, Russia has lost its leading role.

At the same time, the government has managed to significantly increase the revenues of the Federal Budget in the form of tax payments and by establishing a stabilisation fund, a ‘safety cushion’, for the country that played an important role during the crisis (see Figure 5). In Russia, the oil industry is the main taxpayer, providing 20 per cent of GDP and over 43 per cent of the revenue for the Federal Budget, and is one of the maximum investment multipliers. Growing investments in the oil sector result in orders that are placed with such industries as civil engineering, metallurgy, pipe manufacturing, machine building, transport, power generation and services, among others.

In the post-crisis period, the oil industry must play a key role in the transition to an innovative economy, guaranteeing budget revenues and stimulating the development of science-intensive production and research, without which the Russian oil industry may face stagnation.

Oil production volumes achieved in Russia may also be similarly maintained with large-scale projects in new regions such as Eastern Siberia, the Far East and the Arctic shelf, where operations have already started. In particular, Rosneft is currently implementing the Sakhalin 1, 3 and 5 offshore projects in the Sea of Okhotsk, and is developing the Vankor and Urukhech-Tokhoma fields in Eastern Siberia.

The Vankor project is a good illustration of the role of the oil industry in the innovative development of the economy. The construction of field facilities on Vankor is one of the most recent and largest projects undertaken by the industry. In Russia alone, more than 60 design institutes, 150 equipment suppliers, 65 manufacturing plants and more than 450 contractors were employed. Field facilities construction on such a large scale was designed in partnership with leading Russian and international engineering companies. Up-to-date technology has meant that from designing field facilities to commencing commercial production on this project has taken just three years. Further use of modern technology will ensure...
the safe development of this field in the Far North, a region that hosts a particularly hostile environment.

Vankor may be classified as an integration project for Eastern Siberia and the Far East, as Vankor oil will be the main product to be transported via the first stage of the Eastern Siberia-Pacific Ocean pipeline system. In fact, the Vankor field represents a breakthrough in the Russian oil sector and technologies that are currently being applied there will establish a benchmark for the efficient development of the whole of Eastern Siberia in the future.

After 2016, hydrocarbon resources which cannot be developed with available technologies and equipment now will become the main oil resource base. These difficult-to-produce oil and gas reserves include high-viscous, low-permeable and under-gas-cap deposits with a maximum 15-25 per cent oil recovery factor. It is anticipated that with further technological development, the oil recovery factor may reach 55 per cent.

Development of these reserves will require a completely new approach, one which will require the highest standards in technology and equipment. Even now, Russian companies and research institutes are required to prepare for the fulfilment of future orders from the oil industry.

Russia also has huge hydrocarbon reserves on the Arctic shelf, estimated at 90-100 billion tonnes of oil equivalent, slightly less than a quarter of the world’s total hydrocarbon reserves. The development of offshore hydrocarbon resources is one of the key factors for the future development of Russia and its position in the global energy market.

Due to a poor knowledge of the region, the probability of Arctic offshore reserves is 3.5-5 times lower than in Eastern Siberia. Offshore development technologies available in Russia and worldwide are not sufficient to develop these offshore reserves. For extensive development of the Russian Arctic shelf, technological breakthroughs in every segment of the industry are needed, from the development of monitoring systems to the construction of sub-sea production facilities.

Exploration costs in these remote and climatically harsh regions are higher than in conventional oil producing regions in Russia: US$400-500 per tonne of incremental proven reserves compared with US$30-50 per tonne in Eastern Siberia. The capital expenditure required to start the production of these offshore reserves is also extremely high.

According to estimates, more than 30 ice-class stationary platforms and about 10 semi-submersible and floating drilling rigs, as well as about 90 ice-class vessels with a dead weight of 70,000-120,000 tonnes will be required for Arctic offshore projects. In terms of complexity these projects are comparable to space projects. It is clear therefore that without the research and development of scientifically-intensive production techniques, Arctic offshore resources cannot be developed.

The national task: to ensure an inflow of investments
The potential development of the industry is constrained by an acute shortage of investment resources. A shortage of projects that are attractive to investors under the current fiscal regime limits investment in the oil industry. Long-term investment cycles require highly profitable projects that are resistant to market trends. The government is actively amending the tax legislation and this will mean altering the taxation system in general, and allowing tax exemptions within the current system. Prompt transition to the new taxation system will ensure an inflow of investments and
give a boost to oil production. Correspondingly, government must take measures to invest in research, development and establishment of science-intensive programmes.

Russia undoubtedly has great potential for meeting the tough challenges facing the oil industry. Its scientists were innovators in the field of world petroleum science and were responsible for many technological breakthroughs in oil production and refining. Unfortunately, since the 1980s, Russia has lost its leading role.

Now, it is time for fundamental and industry research institutes, engineering centres and service companies to become key components of a pioneering development of the oil industry. A 'Technologies Market' is to be built in Russia, with initiatives being coordinated by the leading oil companies, particularly, Rosneft.

Government support for this innovative development of the fuel and energy complex would mean, in the first instance, establishing the conditions for innovative development, including the preparation of government research programmes, government financing of venture funds and research centres and the establishment of technology clusters and tax exemptions.

However, for this new development of the oil industry to succeed, accelerated innovative development of related industries is required, particularly in machine building, metallurgy and chemistry, to meet the needs of oil and gas producers, oil refiners and petrochemical companies.

Fulfilment of these top-priority measures along with the development of an integrated programme for the innovative development and modernisation of Russian industry would improve the competitiveness of Russian companies and provide additional incentives for Russian economic growth generally.

**Figure 4. Dynamics of Oil Production in Russia**

<table>
<thead>
<tr>
<th>Year</th>
<th>Million tons</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
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</tr>
<tr>
<td>2001</td>
<td>15</td>
</tr>
<tr>
<td>2002</td>
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<td>101</td>
</tr>
<tr>
<td>2008</td>
<td>110</td>
</tr>
<tr>
<td>2009</td>
<td>113</td>
</tr>
</tbody>
</table>

**Figure 5. Wealth of Oil and Gas Funds of Russia**

<table>
<thead>
<tr>
<th>Year</th>
<th>Bn rubles</th>
</tr>
</thead>
<tbody>
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</tr>
<tr>
<td>2008</td>
<td>6612</td>
</tr>
<tr>
<td>2009</td>
<td>4600</td>
</tr>
</tbody>
</table>

Investment in innovation: the key factor in an oil company’s competitiveness

Oil companies participate directly in establishing, developing and introducing technologies to meet their operational targets.

The systematic technological development of Rosneft was a key factor in ensuring its leading position as a company in Russia and worldwide. Today, Rosneft is the largest company in the Russian oil industry, competing with international majors in key production indicators (Table 1).

The targets of Rosneft’s innovative approach are determined by the strategic tasks of the company and correspond to Key Performance Indicators (KPI). Large-scale investments are required to achieve these goals. According to preliminary estimates, Rosneft’s investments in ongoing modernisation programmes will amount to 530 billion rubles by 2014. Together with other operational development programmes, the overall volume of investments will amount to 2.1 trillion rubles.

The sources of Rosneft’s innovative development include its own technologies and developments engineered in cooperation with leading Russian and foreign research and development centres (about 38 per cent), as well as technologies obtained through Russian and foreign service companies (about 62 per cent).

The company cooperates with 28 Russian research centres and academic institutes and 12 foreign research centres in the form of long-term research and development programmes that are of practical importance to Rosneft. The company reconstructs connections between the fundamental science and industry research and actual operations.

Rosneft establishes research and development clusters in every major region on the basis of its own corporate
international partner should arrange project finance, transfer the experience of managing large-scale projects, and ensure the creation of service infrastructure in Russia, as well as quality engineering with the transfer of knowledge and experience to Russian contractors.

It is very important to make sure that imported technology is used as a lever for the accelerated development of Russian technologies and equipment, putting an end to technological dependence on imports. Of course, international fora, particularly, the World Petroleum Council (WPC) constitute one of the most important forms of international scientific and technical cooperation. The Russian National Committee of the World Petroleum Council (RNC WPC) was specially formed for this purpose and has been functioning for over 50 years.

RNC WPC unites production, service and research and development companies, organisations in academic institutes and institutes of the Russian Academy of Sciences, ensuring a full representation of the Russian oil and gas complex. Well-known experts and scientists work in public sections of the Committee.

Recently, RNC WPC has been developing direct bilateral relations with other national committees of the World Petroleum Council. Russian-Chinese oil and gas cooperation fora established by the Russian and Chinese national committees are a good example of such relations. The first such forum was held in 2007 in Beijing, the second one took place in 2010 in Moscow. These events proved to be a very effective way of exchanging information and we, together with our Chinese partners, have decided to continue this practice in the future.

In conclusion, I would like to emphasise that the stimulation of innovations, investment and cooperation is essential for the Russian oil industry if it is to achieve a new operational level; from the exploration and development of new hydrocarbon reserves to refining, engineering and producing new fuels.

The development of the oil industry gives, in turn, a substantial boost to the Russian economy and will facilitate a shift towards a more innovative development model.
Going North: realising the Arctic’s hydrocarbon potential

BY HEGE MARIE NORHEIM
SENIOR VICE PRESIDENT, NORTHERN AREAS EXPLORATION & PRODUCTION NORWAY, STATOIL

The discovery of oil in 1969 was a rags-to-riches fairytale for Norway. But now the giants of the deep are shrinking. What does the future hold? Will our past experience enable us to solve the challenges of the future?

A new chapter is beginning in our home waters. The mammoth fields of the North Sea are dwindling, and the game is changing. Although we have the highest level of exploration at any time in our history, new oil finds are smaller and scattered. They are also less accessible and more challenging to recover. It is a trend that’s changing the way we work – but in our business change is the only constant. We have been adapting our technology and refining our methods ever since we started work on the Norwegian continental shelf (NCS), nearly four decades ago.

The quest for new resources is taking us to areas as yet undeveloped – deeper waters, harsher environments, complex reservoirs. As we move steadily northwards, we are crossing new frontiers for our industry: to storm-tossed and icy seas, and wells with high pressures and temperatures. As the largest operator in Norway by far, our innovation is driving development on the continental shelf as a whole.

New areas

Estimates prepared by the US Geological Survey indicate that the world’s total undiscovered resources are equivalent to 1500 years of the current Norwegian production. It is expected that more than 20 per cent of these resources are found north of the Arctic Circle – that is to say, in Arctic and sub-Arctic areas. This equals nearly 300 years of production from the NCS. More than two-thirds of this volume is probably gas and nearly 85 per cent of the resources are expected to be found offshore.

The Norwegian Arctic shelf is unique with its access to infrastructure and no issues of ice due to the Gulf Stream

Oil production on the NCS has already passed its peak. The North Sea has been thoroughly explored and the geology is known. We continue to make finds, but they are smaller. No new exploration acreage has been allocated since 1994. We believe that there are major resources waiting to be found, and we believe that many of them are located in areas where we have not yet been granted access.

The Norwegian authorities opened the Barents Sea for exploration in 1981 and the same year Statoil discovered the huge Snøhvit gas field. Over the course of these thirty years Statoil, the authorities and a number of international players have developed fields and a strong foothold in the far north, partly through drilling of more than 80 exploration wells.

On the NCS the areas off Lofoten and Vesterålen are the most attractive acreage with regard to the possibility of finding large new fields that can warrant independent developments and new infrastructure. Statoil wants the authorities to give careful consideration to how a portfolio of such projects and resource volumes can be realised. These resources could offer a new lease of life for the NCS, extending its life for decades – as well as providing a major boost to local economies.

The border agreement reached between Russia and Norway in the Barents Sea was announced this spring. More than 40 years have passed since Norway and the former Soviet Union started negotiations on this ocean area. The news about the agreement therefore attracted great attention when it was presented. Oil drilling in this area may still be years away. After the agreement has been ratified, guidelines and terms for oil and gas production must be clarified.

The clarification of potential new acreage in this area is of great interest to Statoil. In terms of exploration this is an interesting but very immature area with a high level of uncertainty. A major discovery in the area may be far from shore and potentially face technological challenges related to ice and darkness. It may take up to 20 years before any oil or gas field may come on stream.

Northern areas: Our commitment to responsible development

Few controversies in Norway today are as challenging as the question of exploration off our Arctic coast. We understand the concerns. Our coastline has a uniquely beautiful environment and abundant fish stocks.

But we already operate in the Arctic – and we already comply with the strictest environmental standards in the world. We have drilled more than 80 explorations wells in the Barents Sea since 1981. We built the world’s northernmost LNG plant on the island of Melkeøya by Hammerfest.

A government-sponsored study has concluded that our presence in the Arctic would reduce the total risk of oil spills reaching shore, since the measures we would provide would protect the coast from accidents caused by passing ships.

We would provide the world’s best emergency preparedness against oil spills – and we would continue to coexist with the environment, local communities and traditional industries as we have done for years. We can be relied upon to act responsibly in the Arctic.

Technology and opportunities

Step-by-step technological development characterises the NCS, Statoil and Norwegian supplier companies. We have a 40-year history of industrial development which has seen
The above map shows the status of the petroleum activity areas on the Norwegian continental shelf as of 1st August 2009.
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us move from the south towards the north. We have moved from shallow to deep waters and from surface installations to subsea and remote-controlled solutions. The direction and speed have been determined by market demand, access to resources, new challenges and fields that are large enough to finance the need for new demanding technology.

Major challenges in the Arctic are ice and rough weather conditions, as well as long periods of continuous darkness, cold, very little infrastructure, vast distances at sea, and rich and important ecosystems. The Norwegian Arctic shelf is unique with its access to infrastructure and no issues of ice due to the Gulf Stream.

Statoil is well-positioned in Arctic petroleum activities. First and foremost, Statoil has experience from nearly 30 years of activity in the Norwegian part of the Barents Sea. In the Russian sector Statoil participates in the onshore Kharyaga field as well as the development of the gigantic Shtokman gas field, located 600 km from shore in the Barents Sea. Other international Arctic assets in which Statoil is active are in Newfoundland and Alaska, and we are considering participating in the Greenland authorities’ plans to conduct exploration drilling off their east coast.

Statoil is one of the oil industry’s pioneers when it comes to production in cold Arctic regions. So far, we have developed the world’s only Arctic LNG facility to process production from the Snehvit gas field. Snehvit is located at 70 degrees north, at the same latitude as the frozen seas north of Alaska. Winds, freezing temperatures and turbulent seas make extreme demands on those intending to function and survive here, whether it is the region’s flora and fauna, traditional industry or oil and gas operations. In fact, the Snehvit development represents an important breakthrough for energy recovery in the northern regions.

The surface of the sea reveals nothing. The field is in fact sheltered from the elements at a depth of 300 metres beneath the surface. Every day 20.8 million standard cubic metres of natural gas liquids (NGL) and condensate are transported 143 kilometres through the seabed pipeline to Melkøya by Hammerfest. The Gulf Stream keeps the sea free of ice all year round. Winter storms, however, can whip up huge waves that make surface installations difficult to operate. On the seabed however all is peaceful. The seabed installations have also been constructed in a way that allows the fishing fleet to continue to operate here. Trawlers may be drawn over the seabed templates with no risk of entanglement.

Statoil is the world’s largest operator of subsea wells at depths greater than 100 metres. Subsea or downhole separation of water with associated direct injection back into the field will also be essential in handling production both above and below the ice. Strong technological development in multi-phase transport of mixtures of oil, gas and water is expected to further increase transportation distances. And on top of all this comes electrification and remote operation from shore. The way forward in the Arctic will be dictated by market demand and available technology.

The market for Arctic resources

European countries will have to make decisions that will have a large impact on the future energy mix. Significant new power capacity must be built in the near future to replace existing old capacity and to fulfil new environmental requirements. Gas is the obvious energy choice for the power sector. It is competitive in terms of price and supply security and it has lower greenhouse gas emissions and a long-term potential.

Statoil is the second largest supplier of gas to Europe. Through the flexible and integrated gas pipeline infrastructure and LNG, Statoil can reach large parts of the European markets. The system is also very cost-effective. We exploit economies of scale and keep unit costs low. This means that we are able to develop smaller fields that could not have developed their own transport solution as stand-alone developments. These system properties do not exist to the same degree in other locations, which makes the Norwegian infrastructure unique in a global context.

Statoil believes that the gas demand for power generation will increase in Europe and the US towards 2030. With a strong position in gas we work actively to position ourselves in relation to Arctic gas opportunities. We also have the necessary commercial expertise and the right market positions to take part in this growth.

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Snehvit is Europe’s first export facility for liquefied natural gas (LNG) and the largest-ever industrial project in northern Norway. Natural gas produced from the Snehvit, Albatross and Askeladd fields in the Barents Sea are received and processed at the plant (pictured) on Melkøya island outside Hammerfest.

Photo: Helge Hansen/Statoil
Oil and gas developments in the Caribbean basin

BY DAVID RENWICK
CARIBBEAN ENERGY CORRESPONDENT, WORLD PETROLEUM

The Caribbean archipelago, which stretches from Cuba in the north to Trinidad and Tobago in the south, contains three countries that produce oil and gas – the two mentioned above and Barbados.

For the purpose of this article, however, it makes sense to include Suriname, which is on the mainland of South America and Belize, which is on the mainland of Central America, because both are regarded as ‘Caribbean’ in a political and economic, if not geographic, sense, belonging as they do, to the regional grouping known as the Caribbean Community and Common Market (Caricom).

Trinidad and Tobago is by far the oldest hydrocarbons producer among the five, having first started to extract oil commercially in 1908, which makes the industry 102 years old this year. Belize, on the other hand, is the youngest: its first barrel began gushing out of the ground in 2005, a mere five years ago. Two other Caricom member states are actively looking for hydrocarbons at the moment – Jamaica and Guyana (Suriname’s neighbour in South America).

After producing oil for more than a century, it is perhaps little surprise that crude output in Trinidad and Tobago is falling and is now down to around 106,000 bbl/d, after having attained peak production of 229,589 bbl/d in 1978.

There are several reasons for this – no new discoveries of conventional oil since 2001, when BHPBilliton found a deposit of about 90 million barrels in Oilocene age rock in block 2c, off Trinidad’s north-east coast, only a modest enhanced oil recovery (EOR) programme in existing known formations and little or no attention paid to the recovery of heavy oil (18 degrees API gravity or less), of which there is believed to be at least one billion barrels on land and nearshore Trinidad’s west coast.

This collapse of oil production is particularly significant for Trinidad and Tobago because it means that the government has lost considerable amounts of income, especially in 2008, when prices zoomed up to US$147.50 a barrel: about 58 per cent of its tax revenue is collected from the energy sector.

Oil is also crucial to the maintenance of foreign exchange earnings: about 88 per cent of exports consist of oil, natural gas and petrochemicals. The country’s major oil producer is actually the government itself or, rather, a state-owned entity called the Petroleum Company of Trinidad and Tobago (Petrotrin). Its current output is about 36,848 bbl/d, the majority of which, some 22,300 bbl/d, comes from nearshore fields in the Gulf of Paria off Trinidad’s west coast and operated by its Trinmar subsidiary.

Other significant liquids producers are BHPBilliton Trinidad and Tobago (around 14,000 bbl/d) and BP Trinidad and Tobago (bpTT) with 21,000 bbl/d, although the vast majority of that is the very light oil called condensate, made available in conjunction with natural gas production.

Vigorous efforts to reverse the decline in oil production are currently under way, having been started by the previous People’s National Movement (PNM) government, which lost the May 24, 2010, general election to a coalition of parties known as the People’s Partnership, in which the dominant influence is the United National Congress (UNC), the official opposition in the last Parliament. It is widely expected that the incoming Minister of Energy and Energy Industries, Ms Carolyn Seepersad-Bachan, will continue the policy of her predecessor in this respect.

A key part of this effort is offering new acreage for exploration and seven blocks off Trinidad’s north, east and west coasts are currently open for auction under production sharing contracts (PSCs), Trinidad and Tobago’s preferred method of doing deals with petroleum companies. At least four of the blocks are considered by the ministry to have oil potential.

In the third quarter of 2010 (the time identified by the previous government), a number of blocks in what is known as deep and ultra deep water, well out in the Atlantic to the east of Trinidad and north of Tobago, will also be open for bids by interested explorationists. Deep water is regarded by the ministry as that ranging from 1,000 to 3,500 metres. There are 39 delineated blocks so classified, though only a handful are likely to attract interest because of the financial and technological challenges involved. Earlier exploration in the ‘shallower’ part of the deep in the late 1990s by the likes of ExxonMobil, Shell and BP, identified no oil deposits, so this may also act as a deterrent, although the ministry has acquired much improved imaging since that time.

Deep horizon exploratory drilling on land is already under way, based on PSCs signed in 2008-09 and is also regarded as having oil potential. Deeper drilling – 10,000 feet and below – has never been undertaken to a significant extent on land in Trinidad and Tobago’s century of oil, but it is believed there are new liquid accumulations awaiting discovery there.

An active EOR programme on land and a start on seriously tackling heavy oil are also new crude-winning initiatives that had been announced by the former administration. While oil production has been tumbling, natural gas production, by contrast, has been rising rapidly in Trinidad and Tobago.

In 1996, 679 million cubic feet a day (cfd) of gas was produced. By 2009 that had skyrocketed to 4.2 billion cfd. While new oil finds have been minimal, new gas discoveries have been plentiful – bpTT alone identified about seven new gas fields in the 1990s in the Trinidad east coast continental shelf area, where the majority of such discoveries have been made.
While proven oil reserves have been stuck at 621 million barrels for some time, proven gas reserves have jumped from 8.2 trillion cubic feet (tcf) in 1993 to 15.3 tcf in 2008 (the most recent annual gas reserves audit by the Ryder Scott company that is available). Proven reserves hit their highest point of 20.7 tcf in 2002 but Trinidad and Tobago’s greatly-admired ability to be able to monetise its P1 gas has taken place at a much faster rate than probable reserves have been able to be shifted over to the proven column or entirely new proven reserves added.

The country’s gas commercialisation successes have centred principally on gas-based petrochemical production (11 ammonia plants, seven methanol plants) and liquefied natural gas (LNG): Trinidad and Tobago is now placed seventh worldwide, after entering the business only 11 years ago.

The gas monetisation process is expected to carry on under the new People’s Partnership (PP) government, who will presumably continue with the PNM administration’s policy of using gas to go further downstream to produce the raw materials from ammonia (melamine), methanol (polypropylene), steel and aluminium that can form the basis of a much more diversified local manufacturing sector.

Belize, the new kid on the Caribbean oil block, is still a very modest producer, as is to be expected, after only five years in the business.

Current crude output from the only producing field, Spanish Lookout, is around 5,000 bbl/d, a figure that is expected to rise this year when a second field, Never Delay, starts production. Both are operated by a company called Belize Natural Energy (BNE), 50 per cent owned by individual investors, mainly Irish.

At least 16 other companies are falling over themselves to join what they see as a potential Belize oil bonanza, with the enthusiastic support of the government. Current Belize Prime Minister, Dean Barrow, has said: “we want to encourage as many companies as possible to try and find the considerable amount of oil that we know Belize possesses.”

Barbados, on the other hand, has actually been in the business for 27 years, although its output has tended to hover around 1,000 bbl/d for most of that time. This is refined in Trinidad by Petrotrin and returned to Barbados as fuel oil.

All crude is derived from land fields, under the control of the state-owned Barbados National Oil Company (BNOC) and only one exploratory well has ever been drilled offshore. BHPBilhiton has been negotiating exploration rights to two offshore blocks from a 24-block auction which took place in 2007. The round attracted little international company interest, which may be a telling indication of how the petroleum world views Barbados’ prospects.

Cuba is actually the second largest oil producer in the insular Caribbean, with about 52,200 bbl/d at the present time, having been around 62,000 bbl/d in 2003, so, like Trinidad and Tobago, its crude output has shown a declining trend. All of this comes from land and nearshore fields but the communist isle has placed its faith for the future in the offshore, where it has delineated 59 blocks in its portion of the exclusive economic zone (EEZ) in the Gulf of Mexico.

There are now 10 companies or consortia, including Spain’s Repsol, Norway’s Statoil, India’s ONGC, Venezuela’s PDVSA, Brazil’s Petrobras and China’s Sinopec holding offshore blocks in which they intend to drill. The few wells sunk in the offshore up to now have not been successful but companies are generally taking an optimistic view of Cuba’s EEZ prospectivity.

Suriname’s crude output is now up to 16,000 bbl/d, all of it from three onshore fields under the control of state company Staatsolie. Suriname prefers to leave the offshore to international companies, however, and four of them hold acreage in the Atlantic ocean – Repsol (block 30), Murphy Oil (block 37), Inpex (block 31) and Tullow (block 47). Repsol has had one disappointment so far, with the West Tapir dry hole in 2008 but it is likely to try again and Murphy is expected to drill one exploratory well late in 2010 and another in 2011, followed by Inpex with one well.

Guyana, Suriname’s next door neighbour, with whom it had a long-standing maritime boundary dispute, mainly triggered by expectations of oil discoveries, but which is now settled, is also
actively encouraging offshore exploration. Several offshore wells have been sunk in the 94 years that the country, home to Caricom’s headquarters, has been prospecting for oil but although there have been oil shows, no commercial discoveries have been made. The Horseshoe well, sunk by a small Canadian independent called CGX Energy in its Corentyne block 2002, was a dry hole but CGX, which under its president and CEO, Kerry Sully has displayed dogged faith in Guyana’s prospectivity, is poised to try again in early 2011 with the Eagle One well.

Repsol is also in Guyana as well as Suriname and Cuba and is operator of the Georgetown block, where seismic has now been completed and drilling should commence soon. ExxonMobil and Shell have also acquired seismic in the Stabroek block. CGX also holds two other blocks – Corentyne Annexe and Pomeroon. Onshore Guyana, CGX also drilled three wells in its Berbice concession in 2005 but with no discoveries.

But Jamaica is undoubtedly the most aggressive of all the non-petroleum producing Caribbean archipelago states in its renewed search for oil and gas (either would be acceptable, since Jamaica is on an oil-substitution campaign for electricity generation and would be able to monetise any gas find almost immediately).

After one formal bid round in 2005 and a ‘block road show’ in 2007, the Petroleum Corporation of Jamaica (PCJ), the government-owned agency which handles all exploration arrangements with international companies, has now offered all the 19 remaining open offshore blocks as well as four onshore blocks up for auction under production sharing contracts (PSCs). The offshore acreage is located south, east and north of Jamaica.

Dr Raymond Wright, the country’s ‘Mister Energy,’ who retired as group managing director of PCJ three years ago but has been retained as special projects manager in charge of the block auction, believes there is enough seismic and other data, particularly the 6,118 line km speculative 2D survey by CGGVeritas acquired in 2009, to convince companies of the exploration potential of Jamaica. He is even suggesting that the onshore blocks could contain ‘shale gas resources’. He is convinced that, with oil prices having recovered, explorationists will once again be attracted to ‘frontier petroleum provinces’ and, he insists: “Jamaica very much falls into that category.”

Like Guyana, Jamaica has long been attempting to find oil (for 55 years, in fact) but the Holy Grail has eluded it so far. The earlier bid round and road show did produce some interest from smaller companies, namely, Australia’s Finder/Gippsland for blocks 6, 7, 10, 11 and 12, Canada’s Rainville/Sagres Energy (blocks 9, 13 and 14) and Hong Kong’s Proteam (1, 5, 8 and 17).

No drilling in any of the 12 blocks has yet begun but Finder/Gippsland will probably be first off the mark in 2011.
Canada’s oil sands: meeting future energy demand

BY PETER WATSON
DEPUTY MINISTER OF ENERGY, ALBERTA, CANADA

Alberta, Canada has a long-entrenched international reputation as place of abundant natural beauty. From the majestic Rocky Mountains, to rich prairies and vast forests, its natural heritage is cherished worldwide.

Recently, the world’s attention has been equally focused on what lies below the surface – the second-largest proven oil reserves in the world, the Alberta oil sands.

Alberta now has great opportunity to help play a significant role in meeting growing global energy demand. It also has a responsibility to advance technological solutions that not only apply to environmental challenges with oil sands development but help with sustainable energy extraction worldwide.

The Alberta innovation that helped unlock the resource is also being used to open the door to a cleaner energy future.

Unlocking the resource

Although always a major player in the conventional North American oil and gas industry, it took a technological awakening to put Alberta’s oil sands on the international agenda. Once considered too remote, too difficult to extract and too expensive to produce, the potential of the Athabasca oil sands has grown from initial 1999 estimates of about five billion barrels to today’s estimate of 170 billion barrels of proven, extractable oil. Technology is what got Alberta to this point in less than a decade. While it may not be achieved in our lifetime, the oil sands contain some 1.7 trillion barrels of bitumen.

Alberta’s proven reserves are second only to Saudi Arabia. As traditional sources of crude oil are depleting, Alberta will increasingly be relied upon to meet the need.

As the only non-OPEC, OECD producer with the potential to substantially increase energy production in the short term, Alberta is well on its way to being counted among the major energy suppliers to the world.

Growing energy demand

World energy demand is forecasted to increase by 40 per cent in the next two decades. While there is recognition that the world must transition to alternate forms of energy, carbon-based sources will continue to represent the lion’s share. Estimates of oil demand in 2035 range from 97 million to 113 million barrels per day. It is imperative that the world get its energy to heat homes and fuel engines from jurisdictions that take their environmental responsibilities seriously. Offering a secure, reliable and safe energy source regulated by a stable, democratic government, Alberta is undoubtedly one of those jurisdictions.

Creating opportunities

However, there’s more to the story than just meeting global energy demands. Oil sands activity has major economic benefits, both inside and outside Alberta. An October 2009 report by the Canadian Energy Research Institute found oil sands development will result in an estimated 343,000 new US jobs between 2011 and 2015. The report also suggests an additional US$34 billion to US GDP in 2015, US$40.4 billion in 2020, and US$42.2 billion in 2025. Between 2000-20, the oil sands are expected to generate over 5 million person-years of employment with over one-third of this employment occurring outside Alberta. Investment is forecasted to exceed US$135 billion over the next three to five years.

Technological innovation spurs opportunity

Success wasn’t always in the cards. Historically, the cost of extracting oil from the bitumen sands was enormous – the market value of extracted crude would not cover the capital costs, labour and energy required in the recovery process. Through extensive research into technological solutions, the potential of the oil sands grew exponentially from the inception of the first commercially-viable facility in 1967. Since that time, limited open-pit mining has rapidly evolved into deep underground extraction techniques (in situ) that are less disturbing to the land. In situ methods now account for more than half of oil sands extraction in the region. In total, 80 per cent of the proven reserves are most economically extracted using this technology.

The discovery of cyclic steam stimulation and steam assisted gravity drainage techniques was the biggest factor leading to success. Today, research and development by government, industry and academic partners continually improve upon these techniques while finding new, more efficient and reliable extraction methods.

Overcoming environmental challenges

Although the oil sands are in themselves a solution to meeting growing energy demands, the extraction processes come with their own set of challenges. As technologies evolve to increase the productivity and efficiency of oil sands facilities, research is also focusing a great deal of attention towards mitigating environmental impacts.

Like all large-scale, long-term industrial operations, oil sands extraction has a significant impact on the environment. These are formidable challenges that face the government of Alberta and the oil sands industry. Water use and water quality, tailings pond management, air emissions, greenhouse gases and land reclamation each require unique solutions. Strong legislation and stringent monitoring forms the basis of ensuring environmental integrity. But the real solutions will be found through ongoing, comprehensive research into technological answers to these big ticket questions.
Clean energy research and innovation

Over the next five years, Alberta is expected to invest US$6.1 billion on green technology – that’s more than all the other provinces combined, according to a recent report by the Conference Board of Canada. This includes a commitment of US$2 billion towards carbon capture and storage technology. This is one of the largest investments of its kind in the world in game-changing technology that the Canadian and US governments and global experts deem essential to a cleaner energy future. Alberta is already developing a collection of CCS projects, pipelines, storage and financing that is unique in the world.

More than US$1 billion has been invested by the Alberta government and industry in research and development at academic institutions across the province. Clean energy research focusing on improvements in the oil sands sector is occurring at the two leading universities in the province: the Centre for Oil Sands Innovation at the University of Alberta and the Alberta Ingenuity Centre for in Situ Energy at the University of Calgary.

Government, industry and academic and research centres are committed to finding new and better ways to more quickly reclaim land, further reduce the volume of fresh water used, decrease the size of tailings ponds and increase energy efficiency in the oil sands region.

Addressing climate change

Alberta is also the only jurisdiction in North America with mandatory reduction targets for large emitters across all sectors. This programme incentivises companies to invest in best technology to ensure continued reductions. While the oil sands region accounts for less than one-tenth of one per cent of global emissions, reducing greenhouse gas emissions is top-of-mind. To date, the oil sands region has reduced GHG emissions per barrel of oil by an average of 39 per cent since 1990, with some facilities achieving reductions as high as 45 per cent.

State of the environment

The oil sands region is Alberta’s most heavily monitored region for air, land and water quality. Data from ongoing monitoring partnership organisations helps tell another success story: solutions to environmental challenges are being found. Air quality in the oil sands region is monitored 24 hours a day, 365 days a year and is rated as good 95 per cent of the time. Water monitoring in the regions waterways show no detectable contamination from oil sands operations. While the overall state of the environment is good, ongoing work will ensure continuous improvement.

Investing in the future

The oil sands have always been about innovation and that will continue because not all the answers have been found. There continue to be challenges associated with oil sands production and there’s a lot of work yet to complete. Although solutions will not be developed overnight, government and industry are committed to finding new and better solutions. The past few years show remarkable gains in production efficiency, with few emissions, less energy and less water needed to produce a barrel of oil sands-derived crude. The trend will continue, but we still have a ways to go.

The world will be dependent on carbon-based fuel for some time to come. Alberta’s goal is to be a world class energy supplier and champion of energy technology, while ensuring that development happens in the most socially and environmentally responsible way. The growing global energy demand must be met – Alberta can play a significant role in meeting this demand in a responsible fashion.
Although rich in petroleum and other fossil-fuel resources, Indonesia is currently a net importer of crude oil. What is your view of the prospects for discovering new oil and gas reserves in the country?

My belief is that Indonesia has considerable potential for finding new oil and gas reserves as well as other energy sources, and as Gita Wirjawan, Chairman of Indonesia’s Investment Coordinating Board said recently, the country is focusing on increasing its exploration activities in the short term. As Mr Wirjawan also noted, the government has re-crafted the business plan for Pertamina to set higher ambitions for the company, both from an upstream standpoint and also from a downstream point of view. The government realises that it must work together with Pertamina if there is going to be a long-term future for the oil and gas sector in our country.

Pertamina is planning to increase production to one million bbl/d by 2015 – a target linked to our aspirations to be a world-class National Oil Company (NOC), hence the focus on upstream production. US$4.6 billion is being allocated for investment, with 60 per cent of this set aside for upstream business, including acquisition activities. Pertamina’s production has increased steadily over the past three years. In 2009, the company was the only Indonesian oil and gas company to do so; its competitors’ production figures are all decreasing.

Does Pertamina have plans to convert the country’s substantial coal reserves into petroleum liquids?

Coal Bed Methane (CBM) is a new form of alternative energy but further studies need to be made to ascertain its full commercial viability. We are currently sharing risk with various partners to study its potential and, if it is workable, it would help to offset our sizable domestic gas demand. South Sumatera and East Kalimantan are both considered to have considerable coal resources and consequently, potential CBM sources. Pertamina has four blocks in Indonesia and three of them are currently producing: Blok PSC CBM Sangatta I, Kalimantan Timur; Blok PSC CBM Sangatta II, Kalimantan Timur; and Blok PSC CBM Tanjung Enim, in Sumatera Selatan.

Pertamina is planning to increase production to one million bbl/d by 2015 – a target linked to the company’s aspirations to be a world-class National Oil Company

To what extent will Pertamina need to partner with other international oil companies and NOCs to bring these, and other projects to fruition?

Pertamina is keen to foster partnerships with other companies that are mutually beneficial. Naturally, technological input is important to the company, as is promoting an improved working culture as part of our investment in human resources.

Primary energy demand is increasing in Indonesia and some forecast that electricity consumption will show an annual increase of around 8 per cent in the run-up to 2020. What is Pertamina’s strategic role, alongside State electricity company PLN, in meeting this demand?

The Indonesian electricity sector’s energy resources requirements are primarily coal, followed by fuel oil, gas, water and finally geothermal. Pertamina provides PLN’s energy resources, supplying the company with fuel oil, gas and geothermal energy. The government is planning to reduce the use of fuel oil in stages, from 26 per cent to 1 per cent of total supply by 2018, and gas from 17 per cent to 10 per cent of total supply. Coal and geothermal energy sources will replace them.

In support of this programme, Pertamina is planning to have a coal-fired production capacity of 1.342 MW by 2014 and will, in addition, concentrate on promoting clean and renewable energy – in other words, geothermal. It is one of our core businesses and is growing exponentially. We have 15 of our own operational areas, five joint
contract geothermal areas and two joint venture geothermal areas, nationwide.

Three areas where we are currently operating are Kamojang, Lahendong and Sibayak, which have been producing since 2007, with impressive figures of 15.8 million tonnes of steam and 2.088 GWs of electricity. It is planned to start production at Ulubelu Unit 1 (1 X 55 MW), Ulubelu Unit 2 (1 X 55 MW), Sungai Penuh (1 X 55 MW), Lumut Balai (1 X 55 MW), Hululais (1 X 55 MW), Kotamobagu (2 X 20 MW) and Karaha (1 X 30 MW) in 2011. Once these programmes are fully operational, all that has to be done is to increase their production output.

How would you describe Pertamina’s business today and what is your vision for the future of the company? Pertamina, as a State Owned Enterprise, delivers the biggest profit to the government of any company in Indonesia, and in 2009 found itself in 30th position among the world’s top oil and gas companies (Source: Energy Intelligence Group).

Pertamina is an integrated oil and gas company, operating in both the upstream and downstream sectors. We are the pioneers of Indonesia’s LNG business. Our downstream businesses include refining, distribution, marketing and trading. Although we have the leading market share nationally in fuel products, aviation and lubricants, we are continuing to expand our markets abroad.

Our vision is to be a world-class company and we are confident that we are getting close to it. Pertamina has a clear roadmap setting out a 15-year development agenda. Five years’ work has already been done and our next task is to be a regional leader in Southeast Asia between 2011 and 2016. In the final five years of our plan we aim to be a world-class NOC.

You are the head of a major oil company in an industry that has traditionally been male-dominated. Do you feel any additional responsibility as a role model? Gender equality has never been an issue at Pertamina: women work just as hard as men and take the same responsibility for their work, and as such are given every opportunity to contribute to the company as professionals. My appointment demonstrates that.
One of the most important factors in the successful development of the hydrocarbon sector has been the institutional reform implemented in 2003, which marked a break with the past and started what today is a real success story in Colombia’s petroleum policy: the new role of Ecopetrol, focused on the operation of a chain of production, transport, refining and distribution activities; the promotion strategy and the flexible and transparent business model created by the National Hydrocarbon Agency (ANH).

Proof of the excellent results of their management and the investment confidence which the Colombian government has generated lies in the increase in the number of Exploration and Production Contracts and ‘TECs’, technical evaluation contracts, with the increase in the first of these being particularly outstanding. Whilst for 2002 seven exploration and production contracts were granted, for 2010 the total number is 230. Also, whilst the format of technical evaluation contracts did not exist eight years ago, to date 80 of these have been awarded.

For the forthcoming month of June the Ministry of Mines and Energy and the ANH together have prepared the ‘Open Round Colombia’, in which 225 blocks representing more than 52 million hectares are on offer; 83 companies have confirmed their interest in taking part.

As a result of the preparation of areas with the help of state investment resources, a highly competitive model and intensive promotion efforts, the targets for exploratory activity have been met and widely exceeded, with so far a total length equivalent to more than 74,000 kilometres of two-dimensional seismic information and the drilling of 347 exploratory A-3 wells in the course of the current four-year term.

As a result, in addition to intense activity in the development of heavy crude, the renewal of mature fields, the commissioning of fields which had not been developed, investments in technology and an increase in the output from existing fields, at present production in Colombia is 776,000 barrels a day. By the end of the year this is expected to reach 800,000 barrels a day and in the next five years to break through the million barrel barrier.

This increase in production has also been reflected in an increase in Colombia’s oil reserves, which are currently more than 2,000 million barrels in confirmed reserves and more than 3,000 million across proven, probable and possible reserves. At this point it is worth mentioning that in the year 2002 Colombia’s proven reserves were of the order of 1,631 million barrels and only guaranteed our self-sufficiency to the year 2009. Today, 8 years later, and with more than 1,400 million barrels consumed in that period, the loss of self-sufficiency in petroleum, which was forecast for the year 2009 at the start of President Uribe’s government, has already been deferred beyond the year 2020, which we can claim to have achieved for our country with the petroleum policy we have been promoting in the last few years.

Colombia, although it is not yet an oil country, is shaping up to be one of the most attractive countries in Latin America for prospecting for hydrocarbons because of its competitive contractual terms, the notable improvement in the physical security of operations and the quality of its human resources.

The challenges we are now facing are of a different kind, since the big obstacle of people’s perceptions of the lack of security in operating in Colombia has been overcome. In future we must make sure that the entry of new industries into our regions is accomplished in accordance with all the rules for harmonious relationships with the communities and with the environment, both highly relevant topics which you have tackled on the agenda these last few days. The investments needed for projects already identified throughout the production chain in this sector amount to around US$34,000 million between the years 2009 and 2015.

This figure includes investment in the exploration and development of fields already discovered, expansion and modernisation of the refineries in Cartagena and Barrancabermeja, and also the construction of new transport and storage systems for crude, gas and refined products. 50 per cent of these investments, 12.6 billion pesos, will be borne by Ecopetrol. This does not include the development of new discoveries or new transport and export solutions arising from

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**Colombian Crude Oil Reserves**

<table>
<thead>
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<th>Year</th>
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<tbody>
<tr>
<td>2003</td>
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</tr>
<tr>
<td>2005</td>
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</tr>
<tr>
<td>2007</td>
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</tr>
<tr>
<td>2009</td>
<td>1,478</td>
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Source: Agencia Nacional de Hidrocarburos
these, which are beginning to emerge and which may easily involve additional investments of more than US$2,000 million. On the subject of biofuels we can confirm that the Colombian leadership is already internationally recognised.

When this government took office, the first steps were already being taken, using the example of the experience of countries like Brazil; today, Colombia is consolidating and enhancing its biofuel programme, in the belief that this represents an excellent option for improving the quality of the fuels used in Colombia, investing in clean energy and helping to expand the range of energies available; and also for promoting the generation of new jobs.

Our country has 3 million hectares suitable for the production of biofuels which would not represent a threat to our food supply nor to our native jungle and rainforests, but on the contrary an opportunity to make better use of the land, with a higher density of use per hectare and added value for our economic production.

In addition, throughout almost the whole of our territory mixtures of diesel with 8 per cent and 5 per cent biodiesel are being used and we are working to increase this mixture to 10 per cent throughout the whole of Colombia in the second half of the year. In support of this objective, to date five production plants have been opened and in June another one will be commissioned, giving a production capacity of 486,000 tonnes per annum. These plants will require a total investment of US$158 million and 108,000 hectares of land dedicated to growing the raw materials.

Being aware of the opportunities which these investments represent, the government is working to boost the domestic market and at the same time prepare us to make the most of our export markets. To this end it is essential to ensure access to the markets of North America and Europe and that is what we are working towards.

Other crucial topics are: eliminating the subsidies for liquid fuels, which allowed the government to invest those funds in meeting the needs of the most vulnerable people in Colombia and to make fiscal conditions in the country consistent; and the handling of domestic prices for both petrol and fuel oil. With regard to the creation of the Fuel Price Stabilisation Fund, that has proved a good move because it has helped to mitigate the impact on the Colombian people of the marked tendency of international oil prices to rise.

As we announced in this same context last year, in fulfilment of the government promise to improve the quality of fuels, from 1st January this year the sulphur content of diesel in Colombia has been reduced from 2,500 to 500 parts per million and Bogotá has even cleaner diesel, having switched from a 500 to 50 ppm sulphur content.

As regards gas I would like to say that there is no doubt that achievements have been made thanks to some very favourable circumstances, such as the investments in the 1991 mass production plan for gas and to the reassurance which the discoveries of gas in Guajira in the seventies represented for Colombia. The regulations and the market model chosen were the right ones for that situation but the problems which dogged the model and the regulations came to the fore when the phenomenon of El Niño appeared in the middle of last year.

This work will culminate in the adoption of the policy by means of a CONPES* document or a decree from the government. There is no question of adopting measures which affect a particular segment of the service chain. It is a matter of drawing up an administrative act which will reflect the Ministry’s renewed commitment to and confidence in a sector which has great development potential.

Colombia is becoming increasingly attractive to foreign investors, its enormous wealth of natural and energy resources, its qualified workforce, strategic position, legal stability and business opportunities have brought it to the attention of the major world companies. Its energy policy complies with international requirements and with the needs of a constantly growing country which requires a supply of efficient and clean fuels to ensure its development and social and economic growth.

In the future the rhythm of growth which we have managed to achieve thanks to this government needs to be maintained so that our sector can continue to play a key role in the Colombian economy and in the position of Colombia on the strategic world map.

* National Council for Social and Economic Policy
The legacy of the 16th World Petroleum Congress

BY NEIL MCCRANK
CHAIRMAN, CANADIAN NATIONAL COMMITTEE, WORLD PETROLEUM COUNCIL

The 16th World Petroleum Congress was held in Calgary from 11-15th June, 2000, and was the first World Petroleum Congress to be held in Canada. Its theme was Petroleum for Global Development: Networking People, Business and Technology to Create Value. Almost 3,000 delegates from 97 countries attended the Congress. Overall attendance, including accompanying persons, press and exhibitors totalled 4,600, almost matching the 15th World Petroleum Congress attendance, which was the largest World Petroleum Congress in two decades.

The sessions programme was comprised of over 300 presentations in plenary or feature addresses, review and forecast papers (RFPs), forum papers and posters. The programme was developed by the World Petroleum Congress Scientific Programme Committee with considerable input from the Canadian Organising Committee, the World Petroleum Congress Executive and national committees of other member countries.

The Calgary Congress offered many innovations, including a Global Business Opportunity Centre (an exhibition with a strong business development orientation) and an improved electronic international communication system for national committees, session chairmen, authors, and other Congress participants.

The decision to attempt to bid for a World Petroleum Congress in Calgary was made in 1990 after the Canadian National Committee determined that there was broad industry and government support. The first bid to host the 1997 Congress was not successful, but the Canadian National Committee persisted and in 1996 Canada was awarded the hosting of the 16th World Petroleum Congress. Hosting such a large and prestigious international event was an awesome undertaking but the Canadian National Committee determined to make it a success. The Canadian National Committee appointed an organising committee comprised entirely of dedicated volunteers to develop a budget and organisation that would make Calgary proud. Eventually, under the expert leadership of Co-Chairmen James K. Gray and Ray P. Cej, the organising committee recruited a small staff who, along with over 1,000 volunteers, worked through to the successful completion of the Congress in June 2000.

The 16th World Petroleum Congress was an unqualified success with extensive compliments coming from Congress participants from around the globe. At the time of the Congress, Canada was just emerging as an energy power and Calgary, the host city, was just beginning to take its place as an important energy centre. The 16th World Petroleum Congress was instrumental in developing this reputation.

Shortly after the Congress in 2000, the recognition of Canada as a major supplier of petroleum products was enhanced when the international energy community recognised the extent of the reserves ‘proven and probable’ that existed in Western Canada (approximately 176 billion barrels of oil in the massive oil sands).

With the knowledge that Canada was becoming an energy power, international oil and gas companies began to focus more attention on developing a presence. With that development, it became easier for Canadian oil and gas companies and related companies, such as engineering and service sector organisations, to venture abroad to conduct business in other parts of the world. This also had the added benefit of enhancing the reputation of Canada as an international energy power.

It is acknowledged that the 16th World Petroleum Congress in Calgary contributed to Canada and Calgary, Alberta taking their place on the oil and gas world stage. One of the outstanding legacies to come out of the 16th World Petroleum Congress was a surplus of funds that has been dedicated to educational programmes at Canadian universities and other educational centres. This surplus of funds, due to the strong sponsorship and volunteer support of the 16th World Petroleum Congress, was US$4.2 million.

The 16th World Petroleum Congress was instrumental in developing Calgary’s reputation as an important energy centre

The Canadian National Committee decided to set-up scholarship endowments for energy related studies. This programme has continued since 2000, with over 1,600 scholarships, of US$3,000 each, being awarded over the past several years. This programme became known as the World Petroleum Council Millennium Scholarships Programme and in total awarded US$4,848 million in Millennium Scholarships to attract young people into the petroleum industry. The sponsors of the Calgary Congress in 2000 and many other related sector companies are receiving positive results on their investment in the form of highly motivated, high performing personnel in essential areas of this dynamic industry.

In addition, this scholarship programme has inspired other World Petroleum Congress member countries to develop their own scholarship programmes – Brazil, South Africa and, most recently, the Spanish Organising Committee offered 50 international scholarships for young people in the industry to attend the Youth Forum in Madrid, Spain.

The World Petroleum Congress provides an opportunity for a country to put on display its petroleum resources and its expertise in extracting them. The track record of the Congresses has been for there to be advancements in new ideas generated by the coming together of the world’s leading scientists and executives in the petroleum industry. The 16th World Petroleum Congress was no exception to this rule and the legacy left behind is important and enduring.
The role of LNG’s value chain in the global energy mix

INTERVIEW WITH HAMAD RASHID AL-MOHANNADI
CHIEF EXECUTIVE OFFICER AND MANAGING DIRECTOR, RASGAS

How is Qatar, through the development of RasGas and its sister company Qatargas, contributing to the security and reliability of global energy supplies?
RasGas recently delivered LNG to our 14th country. The delivery to Argentina was added to destinations that include Korea, India, the United States and a number of countries in Europe. Looking to the future, RasGas will work to further expand the destinations of Qatar LNG. It is through these efforts of extending the reach of Qatar LNG that we are helping to satisfy the global demand for reliable and clean energy.

What is the significance of RasGas shareholders’ recent investment in the LNG supply value chain?
RasGas’ shareholders have invested in LNG receiving terminals and secured capacity to ensure delivery of LNG from Qatar to the world’s liquid gas markets in both Europe and North America. These terminals include the Zeebrugge terminal in Belgium, the Adriatic terminal in Italy and the Golden Pass Terminal in the US. These investments have secured sufficient market access and capacity for our new production. These long-term investments are integrated across the entire value chain, creating cost efficiencies and providing diversity, allowing RasGas to become an efficient and reliable LNG supplier in these markets.

How are RasGas and its customers addressing the need for flexibility as a result of volatile market conditions?
RasGas has addressed this in three ways; firstly through our marketing strategy, secondly through our integrated value chain and lastly through diversification flexibility in some of our contracts. The RasGas marketing strategy is to have a balanced portfolio with a global market reach. The integrated value chain, and in particular the flexibility in our shipping, and access to terminal capacity through our shareholders, has provided us with an ability to respond to customers’ seasonal and inter-regional demand. Lastly, in some of our contracts we have the ability to satisfy market demand utilising contract flexibility for diversions.

What is your current outlook for the levels of LNG global demand and supply, and its effect on pricing?
The global long-term outlook for demand for all forms of energy is a very positive one of growth. For natural gas, and by association LNG, the outlook is also a very positive one. For RasGas we continue to focus on key long-term markets and continue to expand our market reach with new customers. It is through this approach of a balanced portfolio of long-term and short customers that we are able to support seasonal and inter-regional demand. The recent delivery of the first Qatar LNG to Argentina supports our view of growing inter-regional demand for LNG.

What are the long-term prospects for Qatar’s North Field, and what share of the global LNG market do you predict for Qatar before the end of this decade?
The North Field is the world’s largest non-associated gas field with proven reserves of 900 trillion cubic feet. In capitalising on our huge reserves of natural gas, the State of Qatar has a multi-directional and fast-track strategy to develop the gas industry, extending across the entire value chain of LNG trains, tankers, receiving and gas storage facilities and pipeline gas.

We will continue providing the world with reliable, long-term, and clean energy, helping to develop sustainable economic growth around the world. By the end of 2010, the State of Qatar will complete all its planned LNG projects with total production capacity of 77 million tonnes per annum to support the global LNG demand growth.

How is RasGas responding to the policies of governments to reduce carbon emissions, and what role can the LNG industry generally play in this regard?
In the wake of the latest Copenhagen conference of parties, the State of Qatar, while not driven by emission reduction targets, has the potential for significantly contributing to worldwide climate change efforts as a leading LNG and hydrocarbons producer. LNG and natural gas will play a more important role in the global energy portfolio as their production is emitting significantly less CO₂ into the atmosphere, compared to other fossil fuels. But LNG production is still an energy-intensive process and as such, many improvements are available or need to be evaluated by a socially responsible industry.

RasGas has invested in the future with its latest facilities benefiting from state-of-the-art technologies and economies of scale resulting in a further reduced carbon footprint.

RasGas is also looking at reducing the impact of its first processing facilities, in particular with major efforts being spent in flare minimisation, one of the eight teams actively involved under the RasGas Emissions Reduction Steering Committee. Compared to 2008, RasGas reduced its flaring by 40 per cent in 2009, for each million cubic feet of raw gas that was brought into the plant. And compared with other LNG companies involved in the industry benchmarking, these initiatives have seen RasGas ranked as the lowest emitter of greenhouse gasses (GHGs) on a normalised basis.

Furthermore, RasGas is working closely with the Ministry of Environment and its shareholders on GHG initiatives. We are developing our corporate GHG policy and strategy. It will cover a myriad of opportunities, many of which are already ongoing such as implementation of best GHG accounting practices, evaluating carbon capture and storage options, energy efficiency improvements and investment in green infrastructures.
Qatar looks forward to big developments as Host Nation

INTERVIEW WITH HIS EXCELLENCY ABDULLAH BIN HAMAD AL-ATTIYAH
DEPUTY PREMIER AND MINISTER OF ENERGY AND INDUSTRY, QATAR

What does it mean to Qatar, and to you personally, to be the host of the 20th World Petroleum Congress?
On behalf of His Highness Sheikh Hamad Bin Khalifa Al Thani, and the people of Qatar, I would like to say how honoured we are to have been selected to host this important global event. It has taken 74 years for the largest petroleum congress in the world to come to the Middle East, where most of the world’s oil and gas reserves are located. The 20th World Petroleum Congress, hosted by Qatar, will focus on the petroleum industry’s role in delivering reliable, sustainable energy to the global market. I am sure the Congress will be a successful and memorable occasion that will not only celebrate the achievements of the petroleum industry, but also make a valuable contribution to the sharing of information and ideas within the industry.

Looking ahead to the Congress, what do you anticipate will be the major themes for discussion?
The Congress theme – Energy Solutions for All: Promoting Cooperation, Innovation and Investment – encompasses a broad range of topics, including the role of gas in the global energy mix, innovations in the supply chain, complementary energy sources and, most importantly, the industry’s commitment to sustainability. Given the high calibre of the speakers that will be present at the event, I am sure that even the most experienced industry professional will come away from the Congress having learnt something new.

Qatar is a world leader in GTL and LNG technology. What major developments do you have planned over the next few years?
Qatar is already the number one producer and exporter of LNG in the world and home to the largest and most modern fleet of LNG tankers. At the same time, it continues to be a pioneer in the gas-to-liquids industry, as well as one of the leading suppliers of petrochemicals, fertilisers and other manufactured products and by-products derived from its natural resources.

Qatar is on track to be the world capital of the gas-to-liquids industry and has embraced a number of commercial-scale GTL projects based on various processes developed by the leading technology providers in the world. These clean, low-sulphur products will play a key role in reducing localised emissions in the coming years.

The Oryx GTL project, which commenced operations in mid 2006, will at full capacity use around 330 million cubic feet per day of lean gas to produce 34,000 barrels per day of GTL products. The Qatar Petroleum-Shell Pearl GTL project will at full operation produce around 140,000 barrels per day of GTL products as well as significant quantities of condensate and LPG. The first stage is expected to come on-stream later this year.

Gas-based petrochemical industries are rapidly expanding with 12 projects under construction and further ventures in the planning stages. The total cost of existing or near completed petrochemical ventures, refineries and metal industries is estimated at over US$20 billion, some US$7.04 billion of which has already been spent on expansion plans with around US$13 billion expected to be spent on ventures planned to be completed and commissioned by the end of this year.

With the global recession and additional gas supply from the US, the LNG business is experiencing some challenges. What is Qatar’s strategy for tackling these challenges?
When you are in this business you need to be resilient to external shocks. We manage changing market conditions by diverting our cargoes to take advantage of opportunities in other parts of the world. Today we are the only country with this level of flexibility. Customers need someone to move very quickly. In the 1990s there were cargoes but there were not enough ships. Today we have the ships, we have the cargoes and we are ready to move quicker than anyone.

One of our biggest challenges is the disconnect that exists in some markets between the gas price per BTU and the oil price. Therefore, one of our key challenges is convincing the world of the need for a more equitable pricing of natural gas. Ultimately, this will benefit both producers and consumers by providing a sound investment environment and adequate supplies of gas at fair prices.

Do you expect there to be closer cooperation between gas exporting countries in future?
The Gas Exporting Countries Forum (GECF), with its secretariat now established in Doha, aims at enhancing cooperation amongst producing and consuming countries. Its goal is the exchange of expertise in gas exploration and transportation, and to draw up frameworks for world gas markets. The GECF is not just about cooperation between exporting countries. The founders actively seek the participation of consuming countries in the development of the gas industry.

Long-term energy trends suggest that world natural gas consumption will increase by an average of 1.6 per cent per year from 104 trillion cubic feet in 2006 to 153 trillion cubic feet in 2030. Natural gas will remain a key energy source for industrial sector uses and electricity generation. The industrial sector currently consumes more natural gas than any other and is expected to continue that trend through 2030, when 40 per cent of world natural gas consumption will be for...
industrial purposes. In particular, new petrochemical plants are expected to rely increasingly on natural gas as a feedstock. It is no exaggeration to say that the future of human prosperity depends on how successfully we tackle the challenge of natural gas supply and demand. The industry needs greater mutual support to ensure the uninterrupted supply of energy to the world, and wise and prudent utilisation of our natural resources. In this context, the role of the Gas Exporting Countries Forum is essential.

The talent shortage, particularly of skilled engineers, and a lack of effective training are often mentioned as challenges for the petroleum industry as it ramps up to meet demand. How should this situation be addressed and what is Qatar doing in this regard? The shortage of qualified manpower is an issue facing the energy industry worldwide. At Qatar Petroleum we have several strategies for ensuring that we have the human resources that we need to keep pace with our ambitious expansion. For example, we are developing strategic links with the educational institutions within Qatar to increase the number of home-grown engineers and other specialists. This cannot solve the shortfall overnight, but it will build up the knowledge base for the future.

Is Qatar looking into developing any other energy sources? Qatar recently signed a MOU with the US Department of Energy in the field of renewable and alternative energy science and technology cooperation. The agreement acknowledges the strategic importance of promoting energy security through diverse energy sources and types, improving cooperation in renewable and alternative energy partnerships, economic growth through clean energy, and reducing global greenhouse gas emissions.

Among the joint initiatives we aim to pursue are advances in carbon capture, transportation, and sequestration technologies. We also look forward to opportunities for co-investment in areas such as photovoltaic technologies and cogeneration of electricity from the oil production process.
Qatar: Host Nation of the 20th World Petroleum Congress

WITH ITS WORLD-CLASS ENERGY INDUSTRY, STRATEGIC LOCATION, ADVANCED TOURISM AND CONFERENCE INFRASTRUCTURE AND TRADITION OF HOSPITALITY, THE GULF STATE OF QATAR IS SETTING THE STAGE FOR A TRULY MEMORABLE CONGRESS IN 2011

Qatar’s dramatic transformation from a tribal fishing and pearling village to a global energy player is a remarkable and inspiring feat of nation building. Oil and gas have given Qatar one of the highest per capita incomes in the world and made it one of the fastest-growing economies. Displaying an enlightened approach to prosperity, Qatar is channelling its wealth not into trophy assets but into funding the advancement of culture, science, and education. Its strategic path towards a post-hydrocarbon economy will be through a vibrant, knowledge-based society.

Incredibly energetic and ambitious, the State of Qatar has emerged from virtual anonymity to become one of the most forward-thinking nations in the Middle-East, with increasing regional and global influence. By 2030, Qatar aims to be an advanced society capable of sustaining its development and providing a high standard of living for all of its people. Qatar's National Vision defines the long-term outcomes for the country and provides a framework within which national strategies and implementation plans can be developed.

A high quality conference and exhibition destination
Reasons why Qatar is ranked as a high quality conference and exhibition destination for the 20th WPC Congress include:
• Easily accessible global crossroads, strategically located astride the new economic powerhouses of the East and the consumer markets of the West
• Progressive, modern Arab state where English is widely spoken
• One of the safest countries in the world consistently ranking high in the Global Peace Index, attracting a host of high profile conferences, exhibitions, and events such as the 15th Doha Asian Games
• Highly eco-aware country, with trailblazing research and technology projects geared towards achieving a sustainable, green and clean future
• Distinct focus on high-end tourism with infrastructure investments geared for the meetings, incentives, conferences, and exhibitions market, supported by a full range of event support services
• Thriving hotel industry with a full range of accommodation options and room capacity rising to 26,000 by 2012
• A place that welcomes visitors as honoured guests and dear friends, blending traditional hospitality with international service standards
• Rich and carefully protected heritage providing a unique visitor experience

A welcoming nation for business
Qatar has welcomed traders to its ports for centuries. Now it is attracting those seeking a quality destination for business, meetings, culture, and sport while enjoying an exotic location.

Incredibly energetic and ambitious, Qatar has emerged from virtual anonymity to become one of the most forward-thinking nations in the Middle East, with increasing regional and global influence. Oil and gas have made the Arabian Gulf State one of the world’s fastest growing economies, Qatar is channelling its wealth into funding the advancement of culture, science and education. Qatar provides an upscale world of facilities and attractions. It is the ideal destination for discerning travellers, so close to Europe yet a world away, offering a cultural experience steeped in Arabian traditions.

The vision for a leading knowledge-based economy
A US$130 billion investment has transformed Doha into the art and culture capital of modern Arabia, illuminated by stunning museums and cultural venues designed by the world’s most prestigious architects. Alongside the new landmarks is a host of luxury hotels perched on the Caribbean-like coastline. Restaurants feature international menus including Asian, Italian, French, and the best of Middle Eastern cuisine.
A thriving nightlife centred in the five-star hotels, state-of-the-art sporting facilities, and sophisticated shopping precincts round up Qatar’s appeal as a truly world-class destination.

Location and heritage
Qatar is a peninsula of 11.437 sq. Km. located halfway down the west coast of the Arabian Gulf. Latest estimates released put Qatar’s population at more than 1.5 million – nearly double the figure in the last census in 2004.

Qataris are passionately committed to upholding their heritage and cultural values while forging one of the most advanced societies in the world. In fact, nowhere else in the world does the past and the present co-exist so harmoniously.

Qatar’s progressive master plan is being hailed as the 21st century model for urban planning, yet many of its signature projects evoke the golden age of the Ottoman Empire.

The Muslim call to prayer reverberates through the age-old souqs (bazaars), competing with the hustle and bustle of progress. Lofty minarets share the skyline with futuristic corporate towers. Young women in black abayahs and young men in white robes vigorously debate foreign policy in the Qatar campuses of top American universities. Remote-controlled titanium robots race champion camels in the centuries-old Bedouin sport. Healing indoor gardens within a steel and glass medical centre are as eagerly awaited as the all-digital facilities.

Arabian experience
Qatar strives to be the archetypal Arabia and enriches visitors’ experience. Beyond the conference rooms awaits an amazing array of authentic Arabian encounters.

Experience the age-old thrills of falconry or camel racing. Marvel at the legendary Arabian horses or the exotic Oryx. Take a desert safari and camp out in Bedouin tents. Listen to the sand ‘sing’ and bask in the breathtaking beauty of a desert sunset. Step into Qatar’s 6,000-year history replete with magnificent forts, quaint seaside towns and ancient
for this new global crossroads. Doha International Airport is served by 26 international airlines which all operate regular flights from Europe, the US, and the Asia-Pacific among others. Qatar is only seven hours away from the capital cities of Europe and Asia and 13 hours from major destinations in North America. A new airport, said to be the benchmark for all future airports, is currently being built to be an international transport hub for up to 50 million travellers each year.

The New Doha International Airport will also be the hub for Qatar Airways, which flies to over 80 global destinations. Qatar Airways is one of the world’s fastest growing carriers and one of only five airlines to be awarded five-star status. It opened the first dedicated terminal for first and business class passengers. Aircraft powered by natural gas, another world first, is next on its agenda.

Tourism and hotels
With a tourism strategy focused on meeting the highest standards in facilities and services, Doha is quickly gaining a reputation for its sumptuous hotels and their extensive dining, entertainment, leisure, and fitness offerings. Qatar is investing US$17 billion over the next five years into tourism infrastructure, including the construction of hotels, resorts and other leisure facilities. To meet demand, hotel capacity will increase by 400 per cent to over 26,000 rooms and apartments by 2012.

New Hub for a New World
The focus of business in the new century has moved east. Qatar’s unique location close to the new economic powerhouses of India, Southeast Asia, and the Far East, as well as the consumer markets of the West, has set the stage
The foundation has a single-minded conviction to create Qatar’s legacy of educational and scientific achievement. Qatar’s capital city of Doha showcases this exciting and ambitious vision. Top-flight American universities, and elite research and technology institutions have sprouted from the desert to form an oasis of knowledge and innovation called Education City. The 1,000 hectare (2,500 acre) enclave includes six universities – Virginia Commonwealth, Weill Cornell Medical, Texas A&M, Carnegie Mellon, Georgetown and Northwestern; the Sidra Medical and Research Centre; and Qatar Science and Technology Park.

Qatar National Convention Centre is a member of the Qatar Foundation and is also located in Education City. On completion in 2012, Sidra Medical and Research Centre (SMRC) will be the first academic medical centre of its kind in the region. Qatar Foundation set up a US$7.9 billion endowment fund to finance SMRC, the largest endowment of a medical centre anywhere in the world.

The Qatar Foundation and its 21 corporate partners in the Qatar Science and Technology Park (QSTP) have invested more than US$800 million to transform Qatar into one of the most advanced countries. QSTP is an international hub for technology-based companies and an incubator for start-up enterprises – the future Silicon Valley of the Middle East.

For Further information on the 20th World Petroleum Congress and contact details visit the website at: www.20wpc.com
Enhanced oil recovery: challenges & opportunities

BY SUNIL KOKAL AND ABDULAZIZ AL-KAABI
EXPEC ADVANCED RESEARCH CENTRE, SAUDI ARAMCO

Recovery is at the heart of oil production from underground reservoirs. If the average worldwide recovery factor from hydrocarbon reservoirs can be increased beyond current limits, it will alleviate a number of issues related to global energy supply. Currently the daily oil production comes from mature or maturing oil fields and reserves replacement is not keeping pace with the growing energy demand. The world average recovery factor from hydrocarbon reservoirs is stuck in the mid-30 per cent range. This challenge becomes an opportunity for advanced secondary and enhanced oil recovery (EOR) technologies that may mitigate the demand-supply balance.

This paper presents a big-picture overview of EOR technologies with the focus on challenges and opportunities. The implementation of EOR is intimately tied to the price of oil and overall economics. EOR is capital and resource intensive, and expensive, primarily due to high injectant costs. The timing of EOR is also important: a case is made that advanced secondary recovery (improved oil recovery or IOR) technologies are a better first option before full-field deployment of EOR. Realisation of EOR potential can only be achieved through long-term commitments, both in capital and human resources, a vision to strive towards ultimate oil recovery instead of immediate oil recovery, research and development, and a willingness to take risks. While EOR technologies have grown over the years, significant challenges remain. Some of the enablers for EOR are also discussed in this paper.

EOR/IOR definitions

At this stage, it is important to define EOR. There is a lot of confusion around the usage of the terms EOR and IOR. Figure 1 shows these in terms of oil recovery, as defined by the Society of Petroleum Engineers (SPE)\(^1,2\). Primary and secondary recovery (conventional recovery) targets mobile oil in the reservoir and tertiary recovery or EOR targets immobile oil (that oil which cannot be produced due to capillary and viscous forces).

Primary, secondary and tertiary (EOR) recovery methods follow a natural progression of oil production from the start to a point where it is no longer economical to produce from the hydrocarbon reservoir. EOR processes attempt to recover oil beyond secondary methods, or what is left. Recovery, especially EOR, is closely associated with the price of oil and overall economics. On average, the worldwide recovery factor from conventional (primary and secondary) recovery methods is about a third of what was originally present in the reservoir. Improving the recovery factor can be achieved by deploying advanced IOR technologies using best-in-class reservoir management practices, and EOR technologies.

Worldwide EOR oil production

The total world oil production from EOR has remained relatively level over the years, contributing about 3 million barrels of oil per day (Figure 2), compared to ~85 million barrels of daily production, or about 3.5 per cent of the daily production. The bulk of this production is from thermal methods contributing ~2 million barrels of oil per day. This includes the Canadian heavy oil (Alberta), California (Bakersfield), Venezuela, Indonesia, Oman, China and others. CO\(_2\)-EOR, which has been on the rise lately contributes about a third of a million barrels of oil per day, mostly from the Permian Basin in the US and the Weyburn field in Canada. Hydrocarbon gas injection contributes another one third of a million barrels per day from projects in Venezuela,
the US (mostly Alaska), Canada and Libya. Hydrocarbon gas injection is mostly implemented where the gas supply cannot be monetised. Production from chemical EOR is practically all from China with the total worldwide production of another third of a million barrels per day. Other more esoteric methods, like microbial, have only been field-tested without any significant quantities being produced on a commercial scale.

These numbers were taken from the SPE literature, Oil and Gas Journal and other sources, and probably are a little conservative because some of the projects are not reported, especially the new ones. A better estimate of the total EOR production will be about 10-20 per cent higher than the 3 million per day figure quoted above.

**EOR current status**

The global average or aggregate recovery factor from oil reservoirs is about a third. This is considered low and leaves a substantial amount of oil underground. A global effort has been under way for some time to increase this number and one reason for its failure is the relationship between oil price and resource availability. Figure 3, from the International Energy Agency, shows the connection between production cost and oil resources and the cost of converting them to reserves.

The cheapest injectant for producing oil is water. As long as companies can produce oil by injecting water, they will continue to do so. Another ~2 trillion barrels of oil can be produced with the price of oil below US$40 (2008 $) per barrel. Many of the EOR technologies kick in when the price of oil is between US$20-80 per barrel. In the early 1980s there was tremendous interest generated in EOR due to oil price escalation. The number of EOR projects and R&D investment peaked in 1986. The interest fizzled out in the 1990s and early 2000s with a collapse in the price of oil. A renewed and growing interest has taken hold during the past 5 years with a collapse in the price of oil. A renewed and growing interest has taken hold during the past 5 years with a collapse in the price of oil. A renewed and growing interest has taken hold during the past 5 years with a collapse in the price of oil. A renewed and growing interest has taken hold during the past 5 years with a collapse in the price of oil. A renewed and growing interest has taken hold during the past 5 years with a collapse in the price of oil. The lag between the price of oil and EOR projects. In the last price escalation, interest was mostly in the US but this time the interest in EOR projects is global.

Besides the link of EOR to oil price, the projects are generally complex, technology-heavy and require considerable capital investment and financial risks. The risks are aggravated with the fluctuations in the price of oil. The unit costs of EOR oil are substantially higher than those of secondary or conventional oil. Another challenge for EOR projects is the long lead time required for such projects. Typically, it may take several decades from the start of the concept – generating laboratory data and conducting simulation studies – to the first pilot and finally, full commercialisation. Two examples are given here, one each for thermal (Figure 5) and miscible gas injection (Figure 6) projects. While there has been some discussion in the literature of applying or deploying EOR at an early stage of a reservoir’s life, this is generally difficult, and not necessarily the best option, due to the risks involved and lack of data availability, that can easily be obtained during the secondary stage of recovery.

The two most popular EOR methods as discussed below are thermal (steam) and miscible gas injection, which are mature technologies. In chemical EOR, polymer injection is reaching commercial status (Figure 7). Acid gas injection, in-situ combustion (including the newer high-pressure air injection, (HPAI)) and combination chemical flooding are still in the technology development stage. Microbial, hybrid and other novel technologies are in the R&D stage. This compounds and restricts the application of EOR for a given field. If thermal and miscible gas injection methods are applicable to a given reservoir, then the decision to move forward is a little easier. If not, the decision is harder, and depends on the availability of injectant, economics and other factors previously discussed.

**EOR technology matrix**

EOR methods are classified by the main mechanism of oil displacement. There are really just three basic mechanisms for recovering oil from rock other than by water alone. The methods are grouped according to those which rely on (a) A reduction of oil viscosity, (b) The extraction of the oil with a solvent, and (c) The alteration of capillary and viscous forces between the oil, injected fluid, and the rock surface. EOR methods are therefore classified into the following three categories:

- **Thermal methods (injection of heat)**;
- **Miscible gas injection methods (injection of a solvent)**;
- **Chemical methods (injection of chemicals/surfactants)**.
SAGD is primarily being applied in Alberta and several hybrid technologies (e.g., injection of solvent with steam) are being tested. This technology is ripe for being applied in other parts of the world. Air injection, if tamed and understood, may also have applications in light oil reservoirs as the injectant supply is plentiful. Steam flooding too has been tested successfully in light oil reservoirs that satisfy certain criteria (depth < 3,000 ft, oil saturation-porosity product > 0.1).

Miscible gas EOR
Gas injection, especially CO$_2$, is another popular EOR method, and is applicable to light oil reservoirs, in both carbonates and sandstones. Its popularity is expected to increase for two reasons: increased oil recovery through miscibility and disposal of a greenhouse gas. There are over 100 commercial CO$_2$-EOR projects, the bulk of them concentrated in the west Texas carbonates of the Permian Basin in the US. Their success has partially been due to the availability of low-cost natural CO$_2$ from nearby fields and reservoirs. Another important CO$_2$-EOR project is Weyburn-Midale in Saskatchewan (Canada) where CO$_2$ is sourced from a gasification plant in North Dakota and piped across the border. Many other CO$_2$-EOR projects are on the drawing board as a result of environmental reasons (sequestration).

Hydrocarbon gas is also an excellent solvent for light oil reservoirs, if available. In places where it cannot be monetised (no local market), it can be injected into an oil reservoir for EOR. This has been the case in Alaska, Venezuela, California, Indonesia, the former Soviet Union, and Oman. Lesser (small commercial or field trials) have been reported in Brazil, China, Trinidad and Tobago, and other countries. SAGD has been mostly popular in the oil sands and extra-heavy crudes of Alberta, and tested in Venezuela with limited success. Several hybrid versions of SAGD have been reported but remain at field-trial levels only.

In-situ combustion projects, not as popular as steam flooding, have been reported in Canada, India, Romania, and the US. It has been applied mostly to heavy oil sandstone reservoirs. A new version, HPAI, for light crudes has been gaining in popularity over the past 10 years and shows potential, especially in light oils and low permeability carbonate reservoirs. Several projects have been concentrated in the north-western US and Mexico is also considering HPAI for one of its fields.

The future of thermal methods is perhaps the brightest for the more difficult heavy oil and tar sands resources. Currently, SAGD is primarily being applied in Alberta and several hybrid technologies (e.g., injection of solvent with steam) are being tested. This technology is ripe for being applied in other parts of the world. Air injection, if tamed and understood, may also have applications in light oil reservoirs as the injectant supply is plentiful. Steam flooding too has been tested successfully in light oil reservoirs that satisfy certain criteria (depth < 3,000 ft, oil saturation-porosity product > 0.1).

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Hydrocarbon gas is also an excellent solvent for light oil reservoirs, if available. In places where it cannot be monetised (no local market), it can be injected into an oil reservoir for EOR. This has been the case in Alaska, Venezuela, Libya and Canada. Other gases, such as nitrogen (Cantarell field, Mexico) and acid or sour gases (Tengiz field, Kazakhstan, Harweel field, Oman and Zama field, Canada), have, or will be injected, although to a lesser extent than CO$_2$ and hydrocarbon gases. The current challenges in gas injection as an EOR method are gravity segregation, and most importantly, availability of a low-cost gas source.

The future of gas injection lies primarily with CO$_2$. There is a concerted effort around the world to reduce carbon capture costs. Once this becomes feasible, injection of CO$_2$ may become widespread in light oil reservoirs. Hydrocarbon gas injection has limited potential except where there is no market for it.

Chemical EOR
In chemical EOR or chemical flooding, the primary goal is to recover more oil by either one or a combination of the following processes: (1) Mobility control by adding polymers to reduce the mobility of the injected water, and (2) Interfacial tension (IFT) reduction by using surfactants, and/or alkalins. Considerable research and pilot testing was done in the 1980s and a string
of projects were implemented during that time, mostly in the US. Consequently, none of those projects were successful, at least economically. The only place where chemical EOR has been successful, especially polymer, is in China over the last decade. Based on the success in China and the recent increase in oil price, a renewed vigour has come into chemical EOR and several field trials and pilots are ongoing, and/or on the drawing board. The famous one is the Marmul field in Oman. Other projects are in Canada, the US, India, Argentina, Brazil, Austria and Argentina. Surfactant injection has not produced any successes and remains challenging, especially in a high salinity, high temperature environment. Alkalis, although cheap, bring along a string of operational headaches (scaling, emulsions, plugging, etc.). Nearly all of the polymer floods have been implemented in sandstones, and carbonates remain a major challenge.

Chemical EOR faces significant challenges, especially in light oil reservoirs. One of the reasons is the availability, or lack of, compatible chemicals in high temperature and high salinity environments. Alkalis, although cheap, bring along a string of operational headaches (scaling, emulsions, plugging, etc.). Nearly all of the polymer floods have been implemented in sandstones, and carbonates remain a major challenge.

Advanced IOR and best practices
A good ‘first’ option for any reservoir is to maximise secondary stage recovery. Advances in technology and the utilisation of best-in-class reservoir management practices will enable the maximisation of water flooding oil recovery before deploying EOR. Saudi Aramco is perhaps the world leader in optimising the recovery from its reservoirs through prudent reservoir management practices. Some of these include10 the deployment of maximum reservoir contact wells (MRC), intelligent autonomous fields, gigacell simulation, deep diagnostics (ability to see inside the reservoir with clarity), and advanced monitoring and surveillance technologies. These are just a fraction of available technologies that may help improve oil recovery and should be considered before full-scale deployment of EOR.

Another option to consider before EOR is ‘smart water flooding’. Here, the idea is to inject water with an optimised composition (in terms of salinity and ionic composition) into the reservoir instead of any available water that may currently be injected or planned to be injected. Recent research has shown11,12 that salinity and/or ionic composition can play a significant role in oil recovery during water flooding and may yield up to 10 per cent or higher additional oil recoveries when compared to unoptimised water injection. This option has several advantages compared to EOR:

- It can achieve higher ultimate oil recovery with minimal investment in current operations (this assumes that a waterflooding infrastructure is already in place). The advantage lies in avoiding extensive capital investment associated with conventional EOR methods, such as expenditure on new infrastructure and plants needed for injectants, new injection facilities, production and monitoring wells, changes in tubing and casing, for example.
- It can be applied during the early life cycle of the reservoir, unlike EOR.
- The payback is faster, even with small incremental oil recovery.

Figure 9 shows the results from a BP study11 of incremental oil recoveries (over and above water-flooding recoveries) in several sandstone reservoirs.

Smart water flooding is relatively new and in the technology development stage, however, the idea of customised water for improving oil recovery is very attractive. There have been a few field trials and pilots, mostly in sandstones, and fewer in carbonates. The initial results are promising and a number of questions remain, although R&D has been accelerating in

TECHNOLOGY AND INNOVATION
this area. Saudi Aramco, through its upstream arm (EXPEC Advanced Research Centre), has initiated a strategic research programme in this area to explore the potential of increasing oil recovery by tuning the injected water properties.

Another aspect of water flooding that can be improved is the monitoring and surveillance (M&S) of projects. In many cases, adequate monitoring is not done because of the cost involved. This may, however, be detrimental to the overall recovery during water flooding. While an optimum M&S plan cannot be predetermined for a given reservoir, some of its components include: the time-tested open/cased hole logging, coring, flood-front monitoring, single and interwell tracer tests, and emerging technologies, such as: borehole gravimetry, crosswell and borehole to surface electromagnetic (EM), and geophysical methods (crosswell seismic, 4D seismic and 4D vertical seismic profiler (VSP)). A good M&S plan is essential in optimising oil recovery at the secondary recovery stage, and even more important during the EOR phase.

EOR enablers
Significant challenges still remain for the widespread deployment of EOR. Ultimately, however, companies will have to resort to EOR as the ‘easy oil’ gets depleted. This section discusses some of the EOR ‘enablers’5.

Focus on ultimate oil recovery
There is a concerted move around the world as companies (especially the national oil companies, and increasingly the international oil companies) realise that they need to focus on ‘ultimate’ oil recovery and not on ‘immediate’ oil recovery that is driven by short-term profits. This commitment to a long-term view will ensure the optimum exploitation of oil resources by keeping depletion rates low, improving secondary oil recovery through sustainable development and focusing on long-term profits. Appropriate EOR methods can then be deployed to maximise ultimate oil recovery.

Moving towards difficult resources
As the easy and conventional light oil gets depleted, a move towards more difficult hydrocarbon resources is already well under way. These resources include heavy and extra-heavy crudes, oil sands, bitumen and shale oil. Typically, the conventional oil recovery for these resources is generally low. An EOR method has to be implemented relatively early in these reservoirs. This has been, and will be, a primary driver for EOR, especially thermal, in the more difficult resources worldwide.

Life-cycle planning
A more holistic approach in the life-cycle planning of a reservoir is happening across the industry. The motivation towards maximising recovery, rather than thinking about short-term profits, helps in better resource exploitation. Life-cycle planning includes thinking about EOR early enough to conduct relevant R&D studies, feasibility testing and conducting pilots to enable key decisions to be made at the right time.

R&D
Investment in R&D is essential to generate the right options for field development. Often, in a drive to produce oil as fast as possible, incorrect strategy is adopted to develop an
miscible with the oil at moderate reservoir pressures. The number of projects injecting CO2 for EOR has been steadily rising and is anticipated to increase further in the foreseeable future. In many ways, this is a win-win situation, sequestering CO2 at the same time as producing incremental oil.


Capability development

EOR projects are inherently complex compared to conventional recovery methods. These projects are also manpower-intensive, requiring highly-skilled professionals to run them. For companies that nurture, develop and possess these competencies, implementation of EOR will be easier. In addition, EOR professionals also ensure better IOR implementation strategies.

Stepwise implementation

EOR projects are also facilitated by stepwise implementation and integration of R&D, technology, people, and commitment. A stepwise implementation involves moving from laboratory scale tests, single well tests, pilot tests and on to full-field implementation. This will significantly reduce risks associated with typical EOR projects, and eventually improve overall economics.

Energy security

EOR implementation may be aided by a company’s or country’s need for energy security concerns. The US is a prime example of this need and has taken a true leadership role in EOR implementation in its fields, in spite of being a free economy. Another example is PDO where the dwindling oil production rates have forced it to implement EOR projects aggressively.

Environmental concerns

In recent years, a strong boost to EOR has come from environmental concerns. This is especially true for CO2-EOR. CO2, a greenhouse gas, has been closely linked to global climate change. There are incentives to sequester this CO2. It is also a very good solvent for light crudes and is generally
The International Energy Agency (IEA) has recently developed a reference scenario for oil production which indicates that by 2030 half of the estimated total 100 million bbl/day will come from reservoirs and fields that are currently not yet developed or found. This includes Enhanced Oil Recovery (EOR).

A second IEA study, from 2008, concludes that the production-weighted average decline rate for oilfields is increasing from some 7 per cent today to 9 per cent by 2030, which means that it becomes even more urgent to develop the world’s remaining resources. The conclusion is therefore that sustained investment is required to reverse the rapidly declining production. Although these more rapid declines might suggest depleted fields, a lot of oil continues to be left in the reservoirs and Improved and Enhanced Oil Recovery are the key mechanisms to increase ultimate recovery.

If we look at the recovery status of a portfolio of fields, we can introduce the concept of reservoir complexity, a number that indicates how complex a reservoir is in terms of geology and fluid characteristics. Fields with low complexity often have a high ultimate recovery, fields with a high complexity generally have a lower ultimate recovery. A systematic analysis including benchmarking allows us to segment the portfolio into a few groups; one where we speak of top quartile recovery and a number of groups of reservoirs that fall short of this. This type of analysis offers a significant opportunity to screen and plan for improved recovery.

Enhanced Oil Recovery Mechanisms

The physics of oil recovery essentially points to only two major factors that need to be addressed to increase ultimate recovery. The first is lowering the residual oil saturation by changing the wettability or interfacial tension and the second is maximising the sweep efficiency through better well placement or mobility control.

Addressing the geological complexity as well as the fluid characteristics often requires a customised solution. That is why there are a significant number of different EOR processes, of which the optimum has to be selected for each given reservoir. An often heard phrase is “Fluid properties and geology determine the technology”.

In the figure to the right a so-called maturation or S-curve with EOR processes and their technical maturity is depicted. The top right contains a number of so-called mature EOR technologies, such as miscible gas injection, cyclic steam soak, vertical stream drive and polymer flooding, all of which are well established and can be implemented in many situations without significant adaptation.

In the middle are the processes requiring a significant amount of optimising and often field trials to get the correct full field design. These include Alkaline Surfactant Polymer (ASP) flooding, Enhanced Polymer Flooding, In-Situ Combustion (ISC), High Pressure Steam Injection (HPSI), Steam-Assisted Gravity Drainage (SAGD) and Designer Waterflooding.

The technologies in the bottom-left group are immature but very promising and have proven their worth in extensive laboratory experiments and model studies. These require further de-risking in field trials before embarking on full field developments. This category includes catalytic or heater oil upgrade and conversion in the subsurface, use of solvents, gas foams and hybrid processes.

Applications

During the last several years Shell and its affiliates have initiated a significant number of Enhanced Oil Recovery projects covering chemical, thermal and miscible flooding applications in a variety of geological and hydrocarbon settings.

In Syria, successful field trials were conducted with the designer waterflood concept, where the salinity and ion composition of the injection water is designed such that the wettability of the rock is changed to reduce the residual oil saturation. Residual oil saturation reductions of 14 per cent around the well-bore were demonstrated in these trials and our Joint Venture in Syria is now embarking on large-scale developments.

The concept is not totally new. Some 10 years ago we saw the positive effect of switching from injecting saline produced water to fresh water with a clear oil bank response in the production wells in combination with low-salinity water breakthrough. A series of Alkaline Surfactant Polymer trials were also...
conducted in a number of fields in the Middle East and Russia. The successful outcome of these single well tests is a near complete oil de-saturation around the wellbore, in line with the lab tests. Joint Ventures are now progressing plans for continuous injection tests in patterns as a final step before full field implementation.

Key in de-risking and sanctioning these type of EOR projects is a far more detailed understanding of the fundamentals in rock and fluids physics and chemistry that each have a major impact on the ultimate recovery. This required a significant upgrade of our experimental capability to measure relevant rock and fluid properties, as well as the ability to visualise and model the EOR processes at various geological and time scales. State of the art experimental facilities have been built to enhance visualisation and understanding of flow processes in cores, as well as to measure accurate physical and chemical properties under realistic in-situ conditions.

Achieving the technical optimum recovery is not the only criterion for successful field development. Enhancing energy efficiency and minimising the CO₂ footprint have also become important drivers and a number of recent advances have been made that will lead to further improvements in the Unit Technical Cost (UTC) and environmental footprint.

Technical Cost (UTC) and environmental footprint.

The shell proprietary reservoir simulator and modelling toolkit has been upgraded to include relevant EOR processes and rock/fluid interactions in sufficient detail, covering for example In-Situ Combustion, Polymer floods, Designer Waterflooding, Alkaline Surfactant Polymer flooding, Thermally Assisted Gas-Oil-Gravity-Drainage, solvent, and hybrid applications at various modelling scales, ranging from the pore and core scale to full field simulations.

Smart Fields

So far only enhanced recovery mechanisms have been addressed. This is, however, only half of the solution to obtain maximised ultimate recovery. Top quartile Well and Reservoir Management (WRM) is equally important, as many leading operators have demonstrated. WRM for EOR however also requires a next generation of surveillance and WRM tools that are being developed as part of the Smart Fields concept.

Smart fields technology, also referred to in the literature as ‘e-field’ or ‘digital oilfield’ technology, involves an integrated approach (the ‘value loop’ as indicated in the picture on the right) covering data acquisition, the use of reservoir and production system models, decision making and automation and control in the assets in a fully integrated and closed-loop fashion. The measurements may originate from sensors in smart wells, but could also involve simple surface measurements from conventional wells, or originate from other sources such as time-lapse seismic or other areal surveillance methods.

Extending the Smart Field concepts to EOR requires definition of the appropriate levels of smartness for each of the Smart Field Life Cycle: data acquisition, modelling, integrated decision making and operational field management with a high level of integration and automation. For operational EOR projects mainly targeting improved sweep efficiency and operational cost reductions, new surveillance methods and technologies
were developed and deployed in collaboration with oil and gas industry service providers to obtain better and cheaper data.

Example are the use of various geophysical methods to measure (steam) flood performance, high-temperature internal control valves to improve steam injection conformance, fibre optic sensing applications or advanced tracer tests.

Down-hole fibre optics developments for the oil and gas industry are going through a revolution and will see more mainstream applications for a variety of applications in the next decade. With this development comes the PetaByte challenge. Whereas in the last century fibre optics applications such as distributed temperature sensing (DTS) applications had a data rate of several MegaBytes per day, the recently tested down-hole acoustic applications (DAS) produce over a million times more data in the order of several TeraBytes per day. The figure to the right shows the data volume per day in bytes per day for the last several decades. It shows a 1000 fold increase in data volume per decade for a typical measurement in a well. To handle this data volume increase we require a change to the way we acquire, analyse, and store data. Apart from the more obvious improvements in hardware capacity, also changes are foreseen in smarter exception based surveillance and real-time data filtering and processing to avoid storing and analysing all data.

An important part of the Smart Fields concept is closed loop reservoir management to ensure the data gathered in the operations phase is used to improve reservoir models and speed-up the field management cycle. Novel mathematical optimization and control methods are rapidly maturing to assist automatic history matching, high-grading geological reservoir models and reducing the remaining uncertainties, leading to better well off-take or injection policies, high-grading geological realisations as well as improving insights in what key parameters drive the objective function (such as Net Present Value (NPV), cumulative reduction) over the full life cycle, rather than at discrete points in time.

The much faster turn-around cycle resulting from the tighter coupling of real-time data with faster and more responsive reservoir models will result in better and faster decisions. Use of advanced automation and control solutions at the surface (e.g. robotics & automation) and down-hole (e.g. internal control valves) will result in much quicker implementation of the decisions as well. The goal is to reduce the reservoir management feedback loop from months to days. In that way we can optimise reservoir sweep and reduce life-cycle costs, and hence achieve much better ultimate recovery at lower cost levels.

Conclusions

Enhanced Oil Recovery will become an increasingly important part of the oil supply due to more rapidly depleting fields under primary and secondary recovery schemes.

Addressing the geological complexity as well as the fluid characteristics often requires a customised EOR solution for each given reservoir. Top quartile well and reservoir management for EOR projects requires the application of new technologies and workflows to accommodate higher data volumes as well as manage more complex recovery processes.

Apart from pursuing improvements in ultimate recovery, energy efficiency and the CO\textsubscript{2} footprint have become important drivers, and a number of recent advances have been made that will lead to further improvements in Unit Technical Cost (UTC, $/bbl) and environmental footprint.

Dissemination of knowledge, workflows and experience across the various projects has resulted in a global EOR approach shortening the duration of screening, feasibility and development efforts as well as reducing the need for field trial or pilots, overall reducing the cycle time for EOR projects.
Deepwater drilling continues to be expensive, yet the prize remains both elusive and massive. Many of today’s exploration targets lie in the later Mesozoic and Tertiary extensional regimes when vast amounts of salt were deposited, and whether this is highly mobilised such as in the Gulf of Mexico, or mostly still in situ such as offshore Brazil, it presents significant issues and technical challenges. Indeed, the costs associated with addressing many of these have been sufficient to cause a temporary halt in new activity planning when commodity prices fell dramatically in early 2009, but with stabilisation beginning to return, interest is beginning to pick up once again.

Without doubt, the risk of drilling and completing a deepwater well successfully represents a serious challenge to the technology and ingenuity of exploration and production (E&P) companies as well as to the service companies involved. Among the operators, Petrobras has been particularly successful in developing the needed processes as the successes of the Santos basin so clearly demonstrate.

In both sub-salt and pre-salt deepwater prospects, the technical challenges begin with the identification of the potential reservoir. In many ways, the mobilised salt trend in the Gulf of Mexico represents the most extreme geophysical challenge in the world where the problem is to find a way of seeing beneath salt structures that themselves are highly complex. Either energy must be transmitted through the salt and back again, or novel ways of focusing energy around the salt must be found. As most of the energy gets reflected by the top and does not even penetrate the salt the usual approach is to look round the salt in a technique known as wide-azimuth 3D.

This has become the established norm in the Gulf of Mexico and a quick look at multiclient data licenses in this area since 2008 shows that more than two thirds of these sales are associated with wide-azimuth surveys despite the wide availability of newly depth-imaged narrow azimuth data. The message is clear; when it comes to risk reduction, E&P operators do scale down, but aren’t willing to trade down. Indeed as targets become more complex, survey techniques evolve to provide evermore complete coverage, or illumination, of the potential reservoir. One of the latest methods is known as coil shooting where the acquisition seismic vessel steams in a series of overlapping circles thereby constantly varying the azimuth. This has already been proven to provide both better illumination, and significantly lower cost, than wide azimuth, and can be achieved with a single vessel. Yet even this very recent technique has now developed further to a double coil, or helix pattern with the objective of finally unlocking the secrets of the most complicated and thickest salt structures in the Western Gulf of Mexico. Such surveys are also rendered more efficient through the use of the latest-generation seismic vessels that provide improved transit speeds, lower power consumption, reduced emissions and lower levels of pitching and vibration for a friendlier work environment.

In the highly attractive deepwater blocks offshore Brazil, sedimentary salt cannot be avoided. Where it is unevenly deposited, wide-azimuth and coil-shooting patterns will clearly help. However, the main challenge is getting sufficient detail of the shape of the salt to enable proper depth imaging and then ensuring that sufficient energy be available to illuminate the pre-salt section. The final challenge is then to do the best job possible in inverting from seismic data to geology given the paucity of well control.

Traditionally, this is constrained by well data, and it is always improved when calibrated by such information. However, seismic data typically has a gap in its frequency content, which means that it cannot be inverted reliably in the absence of reasonably dense well data. This is very much a Catch-22 situation – to decide where best to place highly expensive wells a reliable inversion is needed, but to make that inversion, a number of wells are needed in the first place.

Technology helps again. To increase the confidence in using seismic for deepwater reservoir characterisation with limited well control, a way must be found to add valid data at the bottom of the spectrum preferably as low as 2 or 3 hertz, which fill...
the gap and allow confident extrapolation a long way away from the well. New DISCover* technology, which involves some seismic streamers towed more deeply – to provide the vital low-frequency content – is yet another example of the way seismic experts are finding new approaches to long-established problems using the unique WesternGeco Q-Technology* single-sensor platform.

**New applications and new products will be needed in order to fully realise the potential of Brazil’s pre-salt resources**

There is, however, one major unknown where seismic signals do not provide a clear answer; what type of fluid is in the reservoir? Borehole-based resistivity – the very first measurement developed by Schlumberger in the 1920s – has long been recognised as a good hydrocarbon indicator because oil-bearing formations exhibit higher resistivities than those that are water-filled. A much larger-scale measurement of the same type, controlled source electromagnetic (CSEM), is now available and acts as a valuable complement to seismic.

It is worth looking at the workflow required to integrate such different measurements as this illustrates the complexity and opportunity offered by frontier exploration. In a typical case the original seismic would have been acquired earlier, perhaps as part of a regional programme. Given the structural complexity of the new areas, as well as the presence of sedimentary salt, a significant investment in depth imaging would be required. Once the seismic has been properly focused and placed in depth, satellite imagery and hydrocarbon seep analysis is added. The integrated information is then loaded into the Petrel® workflow process software and the resulting interpretation analysed by creating a geological history that evaluates hydrocarbon charge, maturation and eventual migration. This, combined with the structural setting, generates several potential prospects, and it is these prospects that are then subjected to CSEM survey to permit an estimate of the fluid type present.

This workflow, enabled by complementary measurements and a collaborative and multidisciplinary workflow sharing a common software platform, is just one example of how our industry is breaking down barriers—barriers that we can no longer afford whether they exist between team members, across disciplines, or between service providers and operating companies.

Some challenges still remain – today’s CSEM measurements are relatively cumbersome, with signal-to-noise levels such that fluid identification below very thick salt is a way off. However, experience is growing and WesternGeco has already completed a multiclient project in the Potiguar Basin, offshore Brazil covering 1300 sq km. Among other geophysical techniques, the change from narrow to wide-azimuth 3D seismic, well established in the Gulf of Mexico, adds value but is little used elsewhere. But the advances in depth imaging, which are extremely computer intensive, are growing rapidly internationally with the algorithms used increasing the computer effort demanded by several orders of magnitude.

I began this story by mentioning both Petrobras’ contribution to deepwater exploration, and the continued high cost of drilling such wells. Clearly, the service industry must pursue its efforts in developing the technology needed to mitigate the risk associated with placing those wells. As the excitement over pre-salt resources leads to the realisation that the development work needed will be immense, it becomes clear that using existing technology in new applications while developing new products to fill the gaps that remain is essential. I believe that part of the solution to this lies in targeted research and engineering efforts focused on specific issues and operated closely with key customers. At Schlumberger, we are already doing this in a number of facilities in Abu Dhabi, Calgary, Dhahran, Kuala Lumpur, Moscow and now Rio de Janeiro. It is an extremely efficient way to address the significant challenges that remain as we come to rely on ever-smaller pockets of oil, trapped in ever deeper and more complex reservoirs.

* Mark of Schlumberger
Reducing GHG emissions: an industry perspective

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Oil and gas account for about 33 per cent of anthropogenic greenhouse gas emissions, of which 85 per cent during their end use by consumers and industry. So greenhouse gases and possible ways to curb emission levels are a matter of concern to the oil and gas industry.

We will not get into the debate on climate change here. However, with industrial operations in 130 countries, we take this issue into account in everything we do and implement effective measures to curtail our emissions. However, targets have to be compatible with our primary responsibility, which is to supply the energy required for economic activity and human well-being and development, now and in the future.

In the context of post-Kyoto policies, as discussed in Copenhagen, Total would like to see a global, balanced agreement come out of the negotiations. As a leading operator in an industry that deals in long-term horizons, we need policies that provide visibility concerning the regulations that will apply over time and in the world’s different regions, so that we can make the right medium- and long-term strategy and technology choices. Right now, without a realistic carbon cost model on which to base forecasts, the economic feasibility of certain options is unclear. The following article describes what we are doing to address these issues.

Total deploys a comprehensive strategy to manage and lessen the climate impacts of all our operations. Our approach focuses on reducing the flaring of associated gas produced with oil, optimising the energy efficiency of our facilities and products, capturing and storing carbon dioxide, and developing alternative energies to supplement oil and gas.

Managing our emissions more effectively: reducing flaring and improving energy efficiency

The first step in minimising our climate impact is to manage the emissions associated with our operations.

In 2009, our greenhouse gas emissions stood at 55 million metric tons of carbon dioxide equivalent. The flaring of unused gas associated with oil production accounted for close to a third of them. In 2000, we decided not to undertake any new projects involving continuous flaring. Since 2004, we have also been a member of the Global Gas Flaring Reduction (GGFR) private-public partnership initiated by the World Bank and have pledged to halve flaring in our operations from 2005 levels by 2014. We deploy a range of solutions tailored to local situations to achieve those goals, including process selection, reinjecting surplus gas into reservoirs, developing the gas as LNG, and reselling the gas to local industry. However, these solutions are not always easy to implement, due to technical complexity or complicated relationships with partners.

Total is also a major consumer of energy. Consequently, using less energy is a priority focus of our greenhouse gas reduction strategy and requires making our facilities more energy efficient. In 2000, we set up an Energy Committee comprised of technical experts and representatives from our various units, to promote a culture of energy efficiency at Total and translate it into practical measures addressing the specific needs of each business.

We set clear targets for improving energy efficiency, ranging from 1 to 2 per cent a year depending on the type of activity involved. Their main objective is to decrease the energy used for industrial processes, by upgrading equipment, better managing installations, especially boilers and furnaces, improving operations monitoring and control systems, and investing in cogeneration units.

We have achieved substantial energy savings. In the last few years, for example, the Carville facility in the United States has increased output 30 per cent while cutting its energy use. In Gonfreville, France, the construction of a new styrene plant boosted energy efficiency 30 per cent, while reducing associated carbon emissions by the same amount. Also in France, we launched the country’s biggest cogeneration unit, at the Normandy refinery, in late 2004. The unit supplies the steam the refinery needs (450 metric tonnes per hour) while at the same time producing 250 MW of electricity that is resold to the power grid.

In addition, in October 2008 the French Environment and Energy Management Agency (ADEME) and Total signed a memorandum of understanding to lead and finance a joint R&D programme to improve the energy efficiency of industrial processes. The programme aims to support small and medium-sized businesses working on energy-saving technologies.

Helping customers shrink their environmental footprint

Most greenhouse gas emissions associated with oil and gas combustion are generated by their use as a fuel for transportation, buildings and industry. That’s why offering our customers products and services that help reduce their consumption and/or greenhouse gas emissions is an integral part of our commitment.

We invest extensively in R&D to develop fuels and lubricants for today’s new engine designs. Since 2005, for example, we have offered drivers automotive fuels formulated to optimise combustion and reduce engine friction loss, with our Total Excellium Diesel and Total Excellium 98 gasoline.

We are involved in biofuels. In 2008, we produced and blended almost 800,000 metric tons of ethyl tertiary butyl ether (ETBE) in gasoline and blended more than 1.4 million metric tons of fatty acid methyl ester (FAME) in diesel, strengthening our position as a leading biofuel operator in Europe.
Finally, for several years now our retail networks have offered our customers advice and services to lower their emissions. Choosing the right fuel and lubricant, checking tyre pressure and engine settings, and practising eco-driving are simple ways to make savings and avoid carbon dioxide emissions.

With our new Total Ecosolutions programme introduced in early 2009, we also aim to design more efficient products and services that will enable our customers to scale back their use of natural resources, such as energy, fossil fuel-sourced carbon and water, and reduce the environmental impacts of their utilisation, including the greenhouse effect and emissions.

After a rigorous evaluation process, 13 products and services have been selected to date, for the fields of transportation and buildings. Our fuel economy lubricants for cars improve fuel efficiency 2.5 per cent, while solutions combine heating oil and solar thermal heating, for example. We have also used innovative petrochemical technologies to develop eco-efficient products. Polyethylene Luminè used to make transparent packaging film, for example, means that our customers who process it into finished products use fewer materials and less energy during manufacturing.

By using this first group of selected products and services, our estimation is that our customers can avoid 500,000 metric tons of carbon equivalent emissions annually, an amount equal to the emissions from 160,000 vehicles over the same period.

Our push to develop more advanced solutions is an ongoing process. We will gradually expand our line of Total Ecosolutions products and services.

Carbon capture and storage (CCS)

According to the International Energy Agency, carbon capture and geological storage could deliver 20 per cent of the required reduction in carbon dioxide emissions worldwide by 2050. The CCS process is well suited to industrial facilities emitting large quantities of carbon, such as thermal power plants, cement plants, refineries, petrochemical plants and steel plants. It supplements efforts to reduce emissions at source, through energy efficiency and renewable or carbon-neutral energies. Total is directly concerned by carbon capture and storage at some of our industrial facilities.

CCS technology is still in its infancy and, compared with the targets that must be met before it can have a real impact on emission reduction, the quantities actually captured and stored today are tiny. Although theoretically there is nothing to prevent its application, several major problems remain unsolved. One of the biggest is its extremely high cost; a combination of technological advances and economies of scale will be required to bring it down to acceptable levels. Regulations will also need to be clarified and the method will have to be explained to the public to make it more acceptable.

We are applying all our knowledge and skills to help improve CCS technologies and facilitate their commercial application. In 2007, for example, we decided to invest in the world’s first end-to-end demonstration project for carbon capture and storage near Lacq, in southwestern France. The project covers the entire industrial carbon capture, transportation and storage chain, from the extraction, treatment and combustion of natural gas, carbon capture via the oxy-fuel combustion process, transportation of the captured carbon and finally its injection and storage in a depleted gas field. Oxy-fuel combustion is a technique that burns fuel using pure oxygen instead of air, to produce waste gas with a carbon concentration of 90 to 95 per cent.

The pilot began operating in early 2010 and will capture and store 120,000 metric tons of carbon over a period of two years.

The primary objectives are to improve our control of the oxy-fuel combustion process, significantly lower the costs and boost the energy efficiency of capture, and gain proficiency in an end-to-end carbon capture, transportation and storage system. This first-ever European storage trial in a depleted reservoir is also expected to validate methods and monitoring tools, for future, larger-scale operations.
It has attracted the interest of the international scientific and technology research community, and in October 2009 was endorsed by the Carbon Sequestration Leadership Forum, a ministerial-level international climate change initiative focused on the development of improved cost-effective technologies for the separation and capture of carbon for its transportation and long-term safe storage.

Also in France, as part of the €100-million Carbon Demonstrator Fund, Total is coordinating an initiative of interest to the energy, refining, petrochemicals, cement and other industries that emit carbon. The project consists of a two-year (2010 and 2011) evaluation of the feasibility of shared commercial-scale transportation and storage infrastructure for carbon-emitting sources north of the Loire River. It would include a demonstration unit to inject 100,000 tons of carbon, the threshold in the relevant EU directive.

This work is part of an international network of operational and R&D projects in which we are participating, in order to pool expertise and share findings for the benefit of all stakeholders.

Helping to create a more sustainable energy mix

As an energy producer and provider, we are developing low carbon energy sources to supplement our core oil and gas business. Solar energy, nuclear power and biomass are our priority focuses.

Total has been active for more than 25 years in photovoltaic solar energy, which is fast becoming more efficient and cost-competitive. We are positioned across much of the photovoltaic chain through our subsidiaries Photovolttech, which makes first-generation, crystalline silicon wafer-based photovoltaic cells, and Tenesol, which designs, produces and installs solar panels.

Technological advances are very important in the solar energy field, which is why we acquired a stake in Konarka, a US startup specialised in third-generation photovoltaic organic cells, in December 2008. We also formed several R&D partnerships in the fall of 2009 with world-class organisations, covering first-generation cells, second-generation thin films, and solar batteries.

Total believes that photovoltaic solar energy is essential to the success of the fledgling energy transition, though it still has a way to go before it really takes off.

By our estimate, nuclear power will grow 30 per cent between now and 2020. Our strategy is to partner with major nuclear industry operators, to combine our knowledge and expertise and our experience in major projects, especially international projects, with the skills needed for nuclear projects. We want to build up our nuclear operations gradually. Total currently has an 8.33 per cent interest in the European Pressurised Reactor (EPR) project being considered for Penly, in northwestern France.

Finally, one R&D avenue we are studying is biomass-to-energy and biomass-to-chemical conversion, reducing competition with food crops. Options under study include biofuels, bio-DME, and the production of bioplastics from sugar through the Futerro joint venture. In 2008, we joined France’s Futuro project to research and develop cellulosic bioethanol and are also participating in the BioTfueL project to develop a biofuel production process based on lignocellulosic biomass. In April 2009, Total also announced the acquisition of an interest in US-based Gevo, which is using innovative technologies to develop a portfolio of bioproducts for the automotive fuel and chemical markets.

As you can see, managing and curtailing greenhouse gas emissions has to be approached from a number of different, strategically interrelated angles that can be combined, with a strong determination to succeed. Total has committed to this path and announced clear objectives. So far, our combined efforts have paid off: from 1990 to 2008, our Refining business cut its specific emissions by 17 per cent and Exploration & Production slashed its specific emissions by 40 per cent. Looking ahead, internal estimates project that by 2015 our initiatives will reduce our total emissions by about 15 per cent from 2008 levels, for a constant reporting scope.

1 Cogeneration is a process improving unit’s energy efficiency, by producing steam and power at the same time.
F
rom the Arctic cold of Northern Norway and the burning heat of the Sahara desert to the wide open prairie of the USA and Canada, carbon capture and storage (CCS) is already being put to use on an industrial scale. CCS is a climate mitigation tool with demonstrated effect that captures the greenhouse gas carbon dioxide (CO₂) from large point sources and locks it away in deep geological reservoirs away from the atmosphere. If we need to achieve significant CO₂ reductions in the coming decades – and I believe this to be the case – CCS should play a crucial part alongside energy efficiency, fuel switching (e.g. coal to natural gas) and renewable energy. Handling CO₂ represents such an important challenge for the oil and gas industry as a whole, that most likely we will have no option but to fully implement and utilise all these tools in our efforts to successfully manage climate change mitigation.

A credible role for CCS
Can we possibly move from our status quo towards a fully-fledged CCS industry over the next 10-30 years? There are no straight answers to that question, but in my opinion the one thing most needed is a sufficiently high and global cost of emitting CO₂ to the atmosphere to support climate change mitigation. This may seem like an unexpected point of view coming from an international oil and gas company. However, it is my belief that nothing is gained by the industry ignoring the issues in our global society as a whole. Producing enough and affordable energy in order to raise the standard of living of billions of impoverished people in developing countries is one of those critical issues that needs to be addressed and resolved. Climate change is another – and very closely linked – challenge. 

Extensive experience with geo-storage
Several aspects of the CO₂-capture, transport and geological storage process are already quite well known to the oil and gas industry. Even so, when compared to the huge global climate change mitigation task at hand, the CCS process as a total chain from source to sink is still in its infancy. There are about five CCS-projects of significance in the world today: Sleipner (Norway), Snøhvit (Norway), In Salah (Algeria), Rangely (USA) and Weyburn-Midale (USA/Canada). These projects all have in common that the CO₂-capture takes place at high pressure and that the cost is baked into the larger cost of the facility as a whole. Thus far no large scale CO₂-capture projects from flue gases (power plants, industrial flue gas) have been realised. Cost estimates for such plants vary by several hundred per cent depending on country, company, retrofit or new-build, brown-field or green-field and so forth. The cost structures are uncertain, particularly for the large CO₂-capture structures and technologies needed. This is one of the main reasons why the Norwegian government, Statoil and Shell joined forces to build the US$900 million European CO₂ Technology Centre Mongstad in order to test and verify improved CO₂-capture technologies from combustion sources. Earlier this year, South Africa’s Sasol also joined the consortium.

There is a substantial and growing support of CCS in the political sphere. One prime example is that the European Union has now started its CCS Demonstration Programme which currently includes six demonstration projects that should be operational by the end of 2015. For the EU, this demonstration programme is essential in order to accelerate technology development, drive down costs, build public confidence – and ensure CCS is commercialised by 2020. As a global solution to combat climate change, CCS is also seen as a way to boost European industry, creating new jobs and promoting technology leadership. As part of the EU recovery package, €1.050 billion has therefore been set aside for funding these demonstration projects.

The new energy and climate package from the EU includes a CO₂-storage directive as well as a revision of the EU emission trading system (EU ETS) that provide regulatory framework and financial incentives for CCS. The CO₂ storage Directive has now to be transposed in EU Member States before June 2011. It proposes rules for managing environmental risks and addresses issues such as exploration permits, storage permits, CO₂ stream, leakages, closure and post-closure obligations by operators and transfer of responsibility. As part of the revision of this Directive in 2015, the EU could even introduce mandatory CCS for all new power plants.

Commercial challenges
A variety of unsolved issues must be addressed and solved before CCS can realise its full potential as a mainstream mitigation vehicle:
• The industry must be convinced that the long-term cost of emitting CO₂ to the atmosphere will be as high or higher than the cost of CCS.
• The capital cost and energy use associated with CO₂ capture must be reduced.
• The risk and liability issues associated with the operation and the CO₂-management after the storage has been closed needs to be fully examined and resolved. The risks of seepage from a storage reservoir are low. However, the financial burden may be perceived as too high for industry and insurance companies compared to the long-term cost savings.
• Agreements allowing countries to store CO₂ in other countries need to be put in place in order to allow for large-scale CO₂
projects such as in the North Sea and elsewhere. In this specific case the recent change of the London Protocol is an important step forward in the right direction.

- The general public and key regulators must identify, understand and support CO₂-storage as a sound, safe and sustainable way of managing CO₂.

**CO₂ is today mostly emitted without cost**

For centuries, mankind has been emitting CO₂ to the atmosphere. For the most part these emissions do not have any costs attached. One of the most important factors holding back the deployment of CCS – and indeed all other climate change mitigation efforts – is therefore the lack of a world-wide, sufficiently high and predictable CO₂ price.

**CO₂ and enhanced oil recovery (CO₂-EOR)**

In 1972, the use of injected CO₂ for getting more oil out of old reservoirs was tested in Texas for the first time. The US is still the front-runner in regards to this oil recovery technology, having some 100 ongoing projects based on naturally occurring CO₂-reservoirs. These projects have provided instrumental learning which has greatly benefited the development of the CCS technology used in projects around the world. A system of 5,000 kilometres of CO₂-pipelines is in place to transport CO₂ in the US and in recent years the technology of CO₂-EOR has spread to countries such as Canada, Brazil, Mexico, Trinidad & Tobago, Turkey, Slovakia and others. Moving forward, it is expected that the Middle East will be an interesting region for CO₂-EOR developments. In October 2009, Saudi Aramco announced that they will be injecting nearly a million tonnes of CO₂ per year from 2013 into the Ghawar oil field. This, I understand, is a pilot project to explore the opportunity for later, larger scale CO₂-EOR in this mammoth field, the world’s largest known oil accumulation.

**Next steps?**

It is my opinion that CCS will move towards becoming more than a strategy for ‘clean coal’, the current focal point of CCS in energy policy worldwide. However, I find it likely that the major oil and natural gas companies will continue to dominate geological storage of CO₂, while other players will dominate the capture and transportation business. My reasoning for this is as follows; the oil and gas companies have many years’ experience of extracting oil and gas from and injecting fluid substances back into geological formations. Secondly, the oil and gas companies are moving into reservoirs with increasingly carbon-heavy oil. Finally, the industry must start to prepare and adjust to these new technologies and tools since regulators and the public in the future will no longer approve the high CO₂ emissions of today’s and the industry have no option but to enforce sustainable operations.

With time, CCS will not only become an integrated part of the oil and gas industry, but it will also be adopted by utilities owning power plants fired by coal, oil, natural gas and biomass. We will also see CCS in the fuel transformation sectors (e.g. refineries) and in emission-intensive industrial sectors such as cement, iron and steel, chemicals, pulp and paper. The present policies and technologies do not take this variety into account, but I think they should, and in ways that does not give rise to serious distortion of competition.

We are also observing an emerging CCS-technology which is highly compatible with energy efficiency, alongside which renewables, fuel switching and nuclear can make a real difference in the fight against climate change. Pioneers among industrial actors, governments, researchers and environmental NGOs are also enthusiastically exploring this path. There are of course, some groups sceptical towards CCS that question its safety and whether the CCS technology will shift the focus from renewable energy or energy efficiency. In my opinion we need all these tools to address climate change and secure sufficient and affordable energy. Therefore, my hope is that CCS will take its place – and be broadly accepted – as a climate solution from an industry seeking not only to be part of the problem, but also aspiring to be a significant part of the solution.
M
erk Oil, like the rest of the industry, has been confronted with a great conundrum, the solution of which could change not just the way oil companies operate but how we all consume energy.

The IEA says demand for energy will increase 40 per cent by 2030 and the overwhelming majority of that increase will come from developing nations, where 1.5 billion people still live with no electricity. Demand for oil will increase 24 per cent over the next two decades just as the industry is facing depleting reserves and increasingly difficult exploration conditions.

At the same time, the IEA in its 2009 World Energy Outlook says that “without a change in policy, the world is on a path for a rise in global temperature of up to 6°C, with catastrophic consequences for our climate”. CO₂ emissions are set to rise just under 40 per cent in the energy sector and 33 per cent as a whole, if no climate policies are implemented, the IEA says. This means the oil industry is placed in a particularly difficult situation – on the one hand we must find the investment and technology to extract more oil than we currently do if we are to keep markets supplied. At the same time, we must learn how to do this in a far cleaner and environmentally responsible way by reducing our CO₂ footprint.

To rise to the challenge of increased oil demand against a backdrop of fewer bountiful and accessible discoveries, some companies have been developing novel recovery processes including injection of water, gas or chemicals into fields to sweep more oil out, under one technique referred to as Enhanced Oil Recovery (EOR). At the same time, to address the issue of climate change, some players in the industry have also begun tentative Carbon Capture and Storage (CCS) projects, whereby CO₂ is captured, transported and locked safely away inside a geological formation, such as a depleted oil field.

We believe that the two processes could go hand in hand – that it could be possible to capture unwanted CO₂ and pump the gas into maturing fields to recover more oil. Such a proposition could provide a win-win solution, helping to both boost oil production out of existing assets and to mitigate CO₂ emissions. We are serious enough about the viability of such a project to have sought out commercial partners and are now surveying our fields for suitable sites for CO₂ injection.

We know that we can squeeze more oil than first expected out of maturing fields through the injection of water or gas into rock formations. In North America producers have been using naturally-occurring CO₂ to do just that for decades. We ourselves are experts at water flooding of our Danish North Sea fields which are characterised by high porosity but low permeability chalk reservoirs. With such experience, we believe we can be capable of EOR operations using CO₂ gathered from power plants or other large emitters of CO₂ that needs to be disposed of safely.

In contrast, there are only a handful of sizeable CCS projects around the world, most notably in Norway, Canada, the United States and Algeria. Yet, the potential of CCS projects is immense – the IEA estimates CCS should provide around 20 per cent of the CO₂ cuts needed from the energy sector to mitigate climate change. The World Bank thinks that figure could be higher at 33 per cent and others still say 50 per cent. But the distance between CCS’s infancy stage and the fulfilment of its potential as a key tool in fighting climate change is huge. One of the key obstacles is cost – it is still significantly more expensive to capture, transport and store CO₂ safely than to pay for the right to emit. Moreover, there is no money to be made purely from CCS.

The regulatory landscape surrounding the environment and energy is now changing fast. Governments across the globe have stepped up their support for a range of projects that are aimed at mitigating climate change. The EU’s executive arm, the European Commission, for example is offering billions of funding for CCS demonstration projects. EU member states and the companies functioning in them are already part of the Carbon Emissions trading scheme, and some governments have imposed or are considering imposing a tax on CO₂ emissions. While such measures may be hard for industries to swallow if they do not change the way they operate, we think the inevitable changes could provide business opportunities.

Measures that make emitting CO₂ into the atmosphere expensive will force industries, particularly the power sector, to take action on CCS. Moreover, combining CCS with EOR, also introduces income into the process, through the sale of the extra oil that can be recovered as a result. Thus, development of CCS-EOR could be a significant activity for the oil industry at a time when it deals increasingly with maturing and challenging fields. As large, accessible discoveries become fewer and far between, many oil companies have begun to focus on getting more out of the fields that they do have.

Around the world oil companies manage to gather just 35 per cent of the oil in their fields on average, according to industry estimates, before recovery becomes commercially unviable and reservoirs are abandoned. Yet, if applied today, industry experience and estimates show that EOR could boost production from existing fields by 5-15 per cent, depending on the specification of each field, where a 5 per cent increase would provide another 10-20 years of oil supplies at today’s rate.

That is why we believe the combined CCS-EOR technology appears to be a win-win solution. It can take damaging CO₂ out of the atmosphere. It can create entire new business opportunities within the industry and it can help oil companies increase supplies from their existing fields to meet global demand and fuel economic growth.
The idea of converting coal and biomass into liquid fuels raises multiple expectations among nations and companies’ strategists, while those less aware of the technology involved consider it as some kind of new alchemy.

CTL can play a part in solving energy security issues. However, the technologies are known to be complex, uncertainties exist regarding their competitiveness, and environment issues are not always clearly assessed.

The commercial experience of CTL has so far been limited to that of one company, Sasol, in South Africa. However, tremendous research work is being done and demonstration plants have recently commenced production with near-to-commercial capacities. Thanks to the considerable information made available in recent years, the benefits of CTL are now better articulated and the questions raised by the process better answered.

**CTL and other acronyms**

CTL generally means the conversion of coal (including lignite) or petroleum coke into liquid fuels.

Biomass is often added to coal. Several projects are referred to ‘Coal-&-Biomass-To-Liquids’ or ‘CBTL’, but the simpler expression ‘CTL’ is often maintained for CBTL projects. In this paper, ‘CTL’ encompasses both CTL and CBTL. At this point, it is important to mention that BTL (Biomass-to-Liquids) is not in the scope of CBTL. We consider that the models of BTL and CBTL respectively are fundamentally different, mainly due to the capacities of the units, which are significantly smaller for BTL than for CBTL units.

The principle of converting coal to liquid fuels is the same as converting it to other fluid hydrocarbons, mainly natural gas and petrochemicals. The processes consist of transforming molecules contained in coal and adding hydrogen to them. The expression “Coal-To-Fluids”, referring to all these types of conversions, is appearing in the industry, reinforced by the fact that the versatility of the processes makes it possible to transform a project initially designed for producing a given fluid to another one for another fluid production.

This paper focuses on CTL, with some references to useful experiences from other CTFs.

**CTL: already a long story**

CTL was first carried out at the beginning of the 20th century in Germany, where two technology routes were developed and patented: the ‘indirect route’ by Franz Fischer and Hans Tropsch and the ‘direct route’, by Friedrich Bergius.

These processes, applied in Germany, became uncompetitive with the discovery of large and easy-to-produce quantities of crude oil in the 1950s.

Later in the century, in order to secure its petroleum requirements, South Africa began an ambitious industrial CTL programme which resulted in today’s only commercial operations. After the second oil shock, several billion dollars were allocated to research on CTL in the US before a slowdown linked to the decrease of the price of crude oil in the 1990s. Today, CTL and more generally CTF projects are being studied in most countries that are rich in coal. China is by far the most active, with several coal-to-chemicals plants already in operation, four demonstration CTL plants accumulating thousands of hours of tests and several coal-to-gas projects officially approved in recent months.

**Energy security**

The comparative availability of crude oil, natural gas and coal on a global basis is universally known. Petroleum products’ availability is key to the independence and development of countries, linked to needs for transportation and defence where liquid fuels cannot be substituted, at least in the medium term.

While reserves and resources of fossil energy are often discussed on a global basis, their geographical repartition...
holds a strategic importance, as fluid energy (crude oil and natural gas) is generally located far from most consuming regions (notably North America, Asia and Western Europe), while coal and lignite are freely available in most of them.

Opportunities also exist in areas where coal is available but expensive to transport, preventing it from being sold on the international market.

**Several technologies available**

Several processes are available to convert coal to liquid fuels, although there are few commercial operations. The processes which today enjoy the most studies and developments can be gathered in (i) the ‘indirect route’ and (ii) the ‘direct route’. They are represented in Figure 1, with pictures illustrating the commercial and ‘demonstration’ plants, which themselves have capacities between 7,000 and 20,000 bbl/day.

The first route is called ‘indirect’ because a first step consists in producing an intermediate: synthetic gas or ‘Syngas’, composed of carbon monoxide and hydrogen. In the second step Syngas is used as a feedstock in four main different processes:

- ‘Fischer-Tropsch’ synthesis produces liquid fuels: this process has been commercially applied by Sasol for decades; two demonstration plants have been started in China in 2009, by Lu’An and Yitai;
- ‘Methanol to Gasoline’ process after methanol synthesis: a demonstration plant, using ExxonMobil's MTG process, is being tested by JAMG in China;
- Production of petrochemicals from methanol: several units exist in China;
- ‘Methanation’, the production of methane or ‘Substitute Natural Gas’; Dakota Gas has operated this process for decades in the US.

In the second or ‘direct’ route, coal is pulverised and mixed in a recycled slurry in which hydrogen is added under pressure. A demonstration plant has been started by Shenhua in China.

Both indirect and direct routes are seen to have respective advantages, in terms of versatility and quality of outputs (naphtha and diesel respectively). Most projects today are based on indirect processes, mainly thanks to the higher level of knowledge accumulated by experience and research so far. The lessons learnt from running demonstration plants will help characterise all tested technologies.

**Sustainable development: two levels of analysis**

CTL is a chemical step included within a long energy channel. It is important to assess its environment footprint at two levels, local and global. ‘Local’ relates to the environmental impact at the place where the material is mined, converted or consumed. ‘Global’ is linked to greenhouse gas emissions.

**Local footprint**

The environmental impact of coal mining is important to manage. Depending on the type of mine and operation conditions, it is controlled by the mining industry and is not within the scope of this paper.

The second step is precisely CTL. CTL presents the same characteristics as chemical and refining operations. The water requirement can be a sticking point. Studies are being made to decrease water needs, but scarce availability can make projects impossible in some areas. The solid wastes generated by CTL processes are the same as the ones produced by power plants and used in the same applications. The treatments of gaseous and liquid effluents are similar to the ones applied in the refining industry and do not raise particular questions.

The third and last step is the consumption or combustion of the fuel. Liquid fuels produced from coal, often referred to as ‘synthetic fuels’, are significantly cleaner, notably in terms of sulphur, than conventional fuels produced from crude oil. Vehicles using these fuels then generate cleaner emissions, which benefits the quality of air in cities.

**Global footprint**

Global footprint is a major issue for any energy channel. CTL’s raw material is coal, the most carbonaceous fossil fuel. This means that, for a given production of energy, CO$_2$ emissions are higher from coal than from other fossil feedstocks such as natural gas or petroleum. In addition, CTL, as an intermediate process between mining and final combustion, requires energy consumption which results in CO$_2$ emissions. CO$_2$ emissions are specifically addressed in CTL projects, most of which include carbon capture and storage (CCS). CCS and other process features will impact the carbon footprint of a CTL plant. However, more than the carbon footprint of the sole plant, it is important to compare the global CTL energy channel to others, from the extraction of primary energy (mining or oil extraction) to final consumption, for example, for a vehicle.

This is done in analyses “from the well to the wheels”: the total greenhouse gases generated are then analysed: primary feedstock extraction, transportation of this feedstock to transformation place, conversion/refining, transportation of finished fuel and final combustion. Published results generally show that total greenhouse gas emissions for liquid fuels produced from coal in CTL plants equipped with CCS are up to 10 per cent lower than conventional fuels produced from crude oil. This compares to an increase of 60-120 per cent if CCS is not applied. The addition of biomass to coal brings significant progress, especially if combined with CCS: the carbon footprint is then...
ALTERNATIVE FUELS

construction and the cost of capital are known when a project is decided. However, the volatility of the price of crude oil over the coming decades remains, with consequences for the financing of CTL projects.

Developments

Most coal-rich countries and mining companies host research centres and conduct technology improvement programmes in CTL. Subjects include the optimisation of classical processes described earlier. Many start-ups, often linked with research centres, contribute to this dynamics, with innovative projects in new areas such as underground coal gasification, CTL+algae or Nuclear+CTL systems.

The industry monitors the results communicated by Shenhua, Yitai, Lu’An and JAMG on the operation of their demonstration plants, which are accumulating thousands of hours of experience. In the medium term, the USA and China have presented forecasts for the development of CTL, which should represent more than 600,000 bbl/day by 2020. Shenhua, the world leader in coal, plans to produce 440,000 bbl/day by that year, with the goal of distributing its production under a self-owned station network.

Conclusion

As coal is freely available in most energy-consuming regions, CTL will remain driven by energy security concerns. Greenhouse gas emissions are a key environmental issue. Technology improvements, CCS and the addition of biomass are the best allies of CTL. They open up opportunities for mitigating the carbon footprint in a more efficient way than conventional liquid fuels. Technologies are available. Today, there are few commercial plants in operation but demonstration units are being operated at close-to-commercial scale.

CTL is capital-intensive. Once the cost of construction and financing is known, project profitability will be subject to the volatility of crude oil prices and the cost of coal. With 2008 energy prices, CTL is highly competitive. Research is being actively developed in CTL. This development and the lessons from demonstration plants in China will pave the way for the short-term development of this industry.

International co-operation has played a key role in the progress made in technology, environment footprint improvement and competitiveness of CTL. Partnerships are now being created regarding financing projects. By providing up to date information on innovation to participants and offering them the best opportunities for meeting other members of the community, the World CTL Conference (www.world-ctl.com) has acted as the catalyst for international co-operations, such as in Beijing on 13-16th April 2010 and next year in Paris in February 2011.
Oil companies have recently acquired positions in sugarcane ethanol in Brazil. After BP’s soft-start, joint-venturing with start-up company Tropical BioEnergia, the boldest step was taken by Shell who announced a joint venture with Brazil’s largest sugar-cane crusher, Cosan. That was followed by Petrobras’ announcement of its US$920 million investment in Açúcar Guarani, a sugar and ethanol producer in Brazil.

Because of earlier developments by international oil companies to adapt their logistics to handle ethanol in most parts of the world, it seems like a logical step to establish positions and construct an international supply chain that will transform today’s fragmented ethanol markets into a more integrated and global marketplace. Some important supply links are still missing, and have been on the drawing board for quite some time, particularly pipeline systems which are designed to enhance transportation efficiency and reliability.

Brazil, the main exporter of ethanol, for example, is heavily dependent on truck transportation and still uses small chemical tanks to store ethanol. Exports are still predominantly made by chemical carriers and demurrage and road congestion remain important issues for ethanol exporters. New supply systems are expected to become operational by the middle of this decade and will significantly improve this situation. In the US, where ethanol moves mostly by rail, there are places like California where bottlenecks for waterborne ethanol imports are relevant.

Market access, however, remains a major hurdle. In spite of encouraging advances over recent years, stemming from the establishment of US RFS, California’s Low Carbon Fuel Standard (LCFS), European mandates or even China’s reduction of import taxes on ethanol, there are still significant hindrances to a global and integrated fuel market.

In the US, RFS targets are still limited by blend walls, waiting for EPA’s position on increasing the blend ratio to somewhere between 12 and 15 per cent, well below Brazil’s long-standing 25 per cent blend. In Europe, with the exception of a few countries, like Sweden, who are open to imports, not many additional imports are to be expected in the next few years, because the increase in local demand has already been taken up, mainly by new plants in Rotterdam and the UK.

China is probably the one country set to benefit most from ethanol opportunities because its oil companies will start looking at opportunities to bring in cleaner fuels to complement their own production which is limited by land and water factors.

As a result of uncertainties related to market growth, investment in new capacity has gone down significantly and forecasts for increases in production over the next five years fall well below potential. Financial backers of the ethanol industry, from equity and debt side, cut credit lines dramatically during the recent crisis, and it is a situation that is not seen as improving soon.

It is interesting to note that, while many developed countries drag their feet and remain entangled in local issues which limit their ability to significantly increase their use of ethanol and other cleaner fuels, Brazil’s demand for this fuel continues to grow strongly at double-digit rates, aided by a few intuitive and simple factors which have been present from the inception of the ethanol programme, more than 30 years ago. Although market mechanisms have dominated the recent increase in demand for ethanol, markets have been free to function because the underlying conditions have been present.

**Acting simultaneously on all links of the supply chain, Brazil has set a new paradigm in renewable energy. Today, sugarcane-derived ethanol is responsible for over half the fuel supplied to light vehicles in the country**

A main factor supporting the ethanol market in Brazil has been government intervention to ensure coordination of changes across the value chain.

Brazil’s ethanol programme was started in the seventies with incentives for sugar producers to invest in new capacity through favourable financing. As new production came on-stream, Petrobras, a government-controlled oil company was made responsible for moving ethanol throughout a country of continental dimensions using its pipelines, tankers and terminals. At the same time, ethanol supply became mandatory across the country, and the automotive industry was stimulated through lower taxes to provide the market with ethanol-dedicated engines. At service stations, designated pumps were and remain available for pure ethanol (E100) delivery.

Acting simultaneously on all links of the supply chain, Brazil has set a new paradigm in renewable energy (it is already a leader in hydropower generation). Today, ethanol is responsible for over half of the fuel supplied to light vehicles, with obvious positive consequences to air quality at city levels and also lower CO₂ emissions and high CO₂ capture.

What is surprising is that, in spite of this model being around for more than 30 years, it is still little known throughout the world. Today, all Brazil’s ‘gasoline’ is in fact a 75/25 blend of gasoline and ethanol (E25): all of the service stations also sell pure ethanol (E100) and, for the past few years, more than four out of five new cars sold in Brazil are flex-fuel vehicles, which can run on any gasoline and ethanol blend. Those who are price-conscious and fill up with the most economical fuel
will normally not be able to work out what the blend ratio is on their car tanks, if alternating fill-ups between ‘gasoline’ (E25) and ethanol (E100).

To Brazilians, it comes as a surprise that most foreigners fail to understand that cars can and do run on ethanol, and that those that do understand are often bombarded by misconceptions propagated by those who see ethanol as a threat.

Take the fuel v food debate, for example. While Brazil is a country 200 times the size of the Netherlands, for example, sugar cane for ethanol production is grown in an area which in aggregate is smaller than that of the Netherlands. Brazil has the largest inventory of degraded pasture lands in the world, enough to be occupied by additional food and energy crops, without even needing to advance into protected areas of the Amazon, a place unsuitable for sugar-cane growth, for climatic reasons.

Going back to oil companies, why is the movement led by Shell relevant? First, because the financial commitments made by these oil companies confirms that sugar cane is the most efficient, cost-effective feedstock for ethanol production and that Brazil will be the major player in this field in the foreseeable future. Sugar-cane ethanol yields 8 units of energy output for every 1 unit of energy input, while corn ethanol yields less than 2:1.

Second, as major gasoline producers move into this market, they will help arbitrate investment decisions in their refining systems where gasoline directly competes with ethanol. Reducing gasoline production demands costly adjustments in refinery configuration and may ultimately lead to the closure of inefficient units, but it also brings opportunities to optimise octave levels and reduce sulphur, aromatics and particulates emissions at a lower cost.

Third, it signals a change in the oil companies’ practice of waiting for breakthroughs in biofuel yields (so-called second-generation biofuels), and suggests they now realise that an efficient platform of production is needed if they are to benefit from future innovations. It may also signal a view that important evolutions are just around the corner. Pilot plants are already being established in Brazil by venture capitalists with the objective of using engineered yeasts to produce not ethanol but diesel-type fuels from sugar. And jet fuel and petrochemicals will follow.

But it would be difficult to see this movement by international oil companies unrelated to expectations of a growing international trade in ethanol. Once cost, reliability and sustainability of the project have been taken care of – obviously through continuous investment, it is the growth of foreign markets that remain the biggest uncertainty. But, that is something that the major oil companies, more than any other agents, are able to understand and it is they who can act to boost trade.

Not only are they close to consumers in the main consuming countries, but they are also more able to engage foreign automotive engine producers, with whom they have a long history of cooperation, into supporting strategies consistent with the introduction of biofuels. It is very difficult, for example, to understand why all cars produced today around the world are not flex-fuel vehicles, as in Brazil, for it is certain that during the next decade, biofuel mandates will inevitably demand that cars are capable of consuming oxygenates. Suffice to say that the flex-fuel cars produced in Brazil are made by manufacturers like: Toyota, GM and Volkswagen that have production lines in Japan, US and Europe respectively. Of course, there are many other manufacturers too.

In short, the participation of international oil companies in the production of sugar-cane ethanol in Brazil is an important sign of progress towards a new and higher level of participation in biofuels in the world energy matrix. However, we must not forget that this is an industry which has developed on the fringes of the mainstream fuels markets, and often in direct competition with oil majors, a situation yet to be settled. Progress in this area will, although benefiting from these new contributors, continue to depend on the efforts of the established ethanol players as well as of those who see this as a next generation fuel – cleaner and more socially and environmentally acceptable. Apart from industry itself, governments will need to, through incisive legislation, play a leading role in stimulating continued growth and access to markets in the biofuels area.
A glance at energy demand projections (Fig. 1) shows a near-doubling over the 40-year period from 1990 to 2030. This goes hand-in-hand with projections for a 55 per cent rise in population, a 150 per cent increase in the number of passenger vehicles on the road, and a doubling of the number of commercial jets in service.

The unavoidable conclusion is that this increasing demand will drive up energy costs as resources become more scarce over time. And this means we have to continue to find alternatives to the energy sources that drove the phenomenal growth of the 20th century – coal and liquid hydrocarbons.

A bridge to future renewables?
The search for alternatives has focused mainly on renewable sources. But something has changed in the last decade that alters all the calculations for the future: the worldwide availability of natural gas, especially shale gas.

If we look at energy sources, liquids are expected to shrink as a percentage of total demand, and nuclear energy is expected to stay flat. Coal, renewables and natural gas will grow. In fact, renewable use could grow at the highest rate over this period. Today, renewables account for some 7.4 per cent of US energy consumption, most of which is hydroelectric power. If, as projected, that figure is 10 per cent in 2030, this suggests, in electricity generation alone, renewables will grow from 300 billion KwH to almost 800 billion KwH. That is the equivalent of more than 50 coal-fired power plants. But how realistic is it to depend on renewable sources to meet this growing demand over the next 20 years? Despite the strong desire by some, the limitations of renewables will not allow this to happen that quickly.

Wind, solar and geothermal energy – which generate only electrical energy – have limitations that will prevent their rapid scaling up to fill the gap. Wind power requires a very large footprint to operate, and the wind does not always blow. Solar power is very costly – three to five times more costly than any other source. Geothermal energy is economically and technically attractive, but it is very location-specific and currently only practical where the tectonic plates meet. Hydroelectric power has similar geographic constraints. And, as they exist today, renewables generate only electrical energy with severe storage limitations and very limited application for powering transportation.

The virtues of natural gas
Natural gas, on the other hand, has properties that help it overcome the limitations of renewables. It has a mature infrastructure in many parts of the world – pipelines, delivery points and storage facilities. And because gas energy is stored in chemical form, it can be physically relocated to meet sudden shifts in demand. Plus, it is an exceptionally versatile fuel source, offering direct heat, power generation and even transportation. More than 11 million natural-gas vehicles are in service worldwide; the technology is proven and commercialised. Also, natural gas produces 29 per cent less carbon dioxide than oil, and 44 per cent less than coal.

Best of all, natural gas is abundant. Even though gas production has climbed in the US in recent years, new technologies and our accumulated experience are allowing us to tap greater reserves. Reserve estimates are growing along with increased consumption.

Reserve estimates have increased by thousands of trillion cubic feet (TCF) and some experts are predicting that shale will provide up to 50 per cent of US natural gas by 2030. The gas is there in the shale plays, and the world is anxious to have it. What more is there to say? It turns out that economic shale gas production is a daunting challenge.

Shale is the most common sediment on Earth, but it is not widely understood. Composition varies widely from one shale play to the next. Each one offers its own set of unique technical completion and production challenges, resulting in a special learning curve for each shale formation.

The keys to unlocking the shales, and, by extension, using natural gas as a bridge fuel to the future of renewable energy, lie in improved understanding of the formation, using more cost-effective technologies to maximise reservoir value, and integrating and optimising the shale gas asset development process. The following discussion touches on some the major inter-related elements.
Shale gas development: Wellbore placement, stimulation and completion

Advances in horizontal-well technology have been decisive in making shale development feasible. Drilling and completing horizontal wellbores exposes much more of the shale formation to stimulation and production.

The first technical challenge is to optimise the wellbore placement, which means navigating through these complex reservoirs with greater precision. A breakthrough in the drilling process is the logging-while-drilling Azimuthal Focused Resistivity Sensor that acquires data in 32 discrete directions around the tool at 14 different depths of investigation – all up to 18 feet into the formation. This information gives early warning of changing lithology and geologic structure. The ability to detect contrasting formations deep into the reservoir provides the confidence necessary to drill faster without the risk of leaving the payzone.

There is no doubt that significant shale gas reserves exist in every part of the world and it is reasonable to predict that reserve estimates in these areas will increase over time as exploration begins.

Once the wellbore is drilled, the extremely low permeability of the surrounding shale formation means that economic production is impossible without stimulation, typically hydraulic fracturing. This operation can account for as much as 50 per cent of the cost of the well. Maximising the return on this investment, like the drilling process, depends on understanding what is happening in the formation and designing the treatment accordingly.

In hydraulic fracturing, one of the important technologies is microseismic fracture mapping. Installing geophones in an offset well enables monitoring the microseisms that occur around the wellbore when the hydraulic fracture process causes the reservoir to deform. This data can be displayed in real time, allowing the stimulation engineers to optimise the treatment design.

Using the seismic curtain as a background, the monitoring software displays the microseisms as coloured spheres (Fig. 2). The relative size of the spheres can even be graded to reflect the magnitude of the microseismic activity. The well trajectory and the top and bottom of the reservoir can be represented as coloured lines. Green spheres can show activity within the bed boundaries, and blue spheres illustrate the activity outside the payzone. When treatment outside the payzone is detected, the engineer can either shut down the treatment early, saving material for future stages, or lower the treatment flow rate.

The purpose of the treatment is to maximise the stimulated reservoir volume (SRV), which correlates very closely to improved production. Achieving maximum SRV is dependent on the ability to see, in real time, what is happening in the formation and to modify the treatment immediately rather than to simply assess the treatment after the operation.

For example, Fig. 3 shows a horizontal well with multiple fracture stages, each represented by different coloured spheres. The spheres are matched with rectangular blocks that are derived from the spatial distribution of the microseismic activity. These blocks represent the stimulated reservoir volume. The information acquired by this treatment can be used to adjust the treatment parameters, such as pumping rate, fluid properties, sand amounts, treatment volumes and spacing along the lateral to help optimise future treatments.

The need to drive down well costs and make shale gas basins economically viable has also led to the construction of horizontal wells with more than 20 frac stages. This is being done with completion technologies that are so efficient that they have helped reduce well completion time by 30-50 per cent.

There are a variety of completion solutions available for shale gas reservoirs; optimising the completion design depends on the specific conditions. For example: Is cement needed to support the formation while providing zonal isolation or can the formation accept an openhole design and compartmentalisation through the use of hydraulic set or swellable packer technology? Is the optimum stimulation a cluster of entry points calling

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**Fig. 2** – Microseismic fracture monitoring changes the game by enabling real-time monitoring of fracture creation and propagation
for a perforated design, or a single entry point with sleeve technology? A range of options is needed to find the one best suited to the reservoir and the surface conditions.

Sleeve technology, in particular, deserves a closer look here. Conventional plug-and-perforate completion methods require intervention for each stage, typically allowing only one or two zones to be stimulated in a 12-hour period. New methods allow as many as nine zones to be completed in 12 hours. Halliburton’s current record is six zones in three hours and 45 minutes. This jump in efficiency comes from using a system of sliding sleeves that enable fracture placement control by consecutively opening the sleeves for sequential treatment of each zone. This technology also enables economical access to the areas of the reservoir that might otherwise be considered marginal and, therefore, left uncompleted.

Using these technologies has allowed an operator in one of the major US shale gas basins to reduce drilling and completion time per well to 32 days. At that rate, an operator rig can drill and complete 10 wells per year instead of the three wells per year with conventional methods.

Natural gas development is environmentally sound

Our industry understands our obligation to develop shale gas assets in an environmentally sound manner and to continually improve our environmental efficiency in the same way we are improving our economic efficiency. We are focusing our efforts on three important areas.

First is the responsible use and reuse of water. Across the industry, considerable effort is being made to develop solutions for the treatment of both produced water and fracture-treatment flowback water. Many of us in the industry believe that innovations such as electrocoagulation will help deliver solutions. Electrocoagulation technology offers an environmentally friendly water treatment option that is not based on chemicals. The technology involves applying an electric charge to a fluid to help remove heavy metals, suspended solids, organic material and many other contaminants.

Second is reducing the overall environmental impact of our operations. This extends from using pad drilling and extended-reach wells, to reducing vehicle miles and the amount of equipment on location, to the possibility of using natural gas to fuel the hydraulic fracturing equipment.

Third is a migration to green chemistry for reservoir stimulation through fracturing treatments. We have succeeded in eliminating the requirement for biocides in fracturing fluids by adopting ultraviolet-light technology, which is familiar from domestic uses such as sterilising tooth brushes.

We have also developed a chemistry scoring index to assign a numeric score to the environmental, physical and health impact of chemistry used in well stimulation. This approach can provide a solid basis for choosing more environmentally focused chemistry while balancing the choices with chemistry performance and overall well-completion costs. This will enable operators to make an informed decision and will assist in ongoing efforts to develop products with improved health, safety and environmental performance.

Bridge to the future

Shale gas development is rapidly advancing in North America, as operators and service companies apply new technologies and assimilate the lessons of experience. So, should we consider shale gas the bridge to an alternative energy future? To answer this question, perhaps we should consider the views of an expert. Theodore Levitt, Professor Emeritus of Marketing at Harvard, in an article entitled *Marketing Myopia*, suggested that the oil and gas industry may find itself in much the same position of retrospective glory as that of today’s US railroad industry9.

This article was published 50 years ago. What Professor Levitt failed to consider was the impact that technical innovation would have in making oil and gas the most cost-competitive energy source. Even today, after half a century of waiting for that prediction to come true, we may discover that this bridge could take another 50 years to cross.

Fig. 3 – Microseismic monitoring can help optimised fracturing results by enabling the calculation of stimulated reservoir volume (SRV)

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1 EIA International Energy Outlook, 2009
2 US Census Bureau Database
3 Vehicle Ownership and Income Growth, Worldwide: 1960-2030 (p 20)
4 Boeing Long Term Outlook
6 http://www.iangv.org/tools-resources/statistics.html
7 http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html
Driving innovation across the LNG value chain

BY MARJAN VAN LOON
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As has been reported by many already, the world needs more energy. By 2050 the global demand for energy is expected to have doubled (IEA's 2009 World Energy Outlook). At the same time environmental stresses are growing: the world must manage its greenhouse gas emissions as a matter of urgency. Over time, cleaner, renewable energy sources will meet an increasing share of demand, but experience tells us that it will take many years to gain overall acceptance of these new energy sources and to build the necessary infrastructure.

At Shell, we estimate that by the middle of this century around 30 per cent of the world’s energy could come from bio-fuels, wind, solar and other renewable sources, and that nuclear could cover around 8 per cent of demand. This will, however, require a massive and coordinated effort by scientists, engineers and investors, and the remaining 62 per cent of primary energy supply will still have to come from fossil fuels. Natural gas, the fossil fuel with the lowest carbon intensity as well as the lowest nitrogen and sulphur dioxide emissions, will play an important role in the future energy mix and in meeting climate change targets. Thanks to innovation, the industry is now able to access the world’s vast unconventional gas resources, providing cost-competitive supplies for many decades. Natural gas can reach consumers in a safe, reliable and efficient manner, both as pipeline gas or as LNG. Shell was involved from the beginning in the LNG industry, as technical advisor in the first commercial liquefaction plant in Algeria, in the design and shipping of the first purpose-built LNG carrier, the Methane Princess (see figure 2), and the buying of the actual LNG from the CAMEL plant for the UK.

Many innovations and technology improvements have lead to more cost effective and efficient plants. This article discusses how Shell is continuously innovating across the LNG value chain from LNG export to LNG import, focusing here on liquefaction and shipping.

Opening new frontiers in liquefaction

LNG train capacities have increased over time in order to capture the advantages of economies of scale. True mega trains of 7 million tonnes per annum (mtpa) and larger have been developed for those locations with very large gas reservoirs.

More recently the focus of technology developments has shifted towards increasing overall energy efficiency and as such, reducing emissions, and towards enabling access to gas resources in more challenging locations like (sub-) Arctic climates or off-shore regions.

New LNG designs, using for example more efficient turbines or waste heat recovery, can have a significant impact on the energy efficiency of LNG plants, thereby saving fuel and reducing CO₂ emissions. But for these designs to become successful in the future, it is important that they are cost competitive compared with less efficient designs. At the same time, it is essential that the new designs do not introduce large technical risks.

Shell developed a next generation LNG train design for the 3 to 6 mtpa range, based on the latest thinking regarding energy efficiency, costs, project and technology risks and operational flexibility. These energy efficient designs, based on aeroderivative gas turbines as compressor drives or heavy-duty gas turbines in combined cycle, are now available and can lead to considerably lower (~30 per cent) CO₂ emissions compared to conventional designs.

The power output of aeroderivative gas turbines is sensitive to ambient air temperature. This can negatively affect the LNG production of designs employing aeroderivative drivers in (hot) climates with large temperature swings. The issue can be solved by chilling the inlet air of the aeroderivative drivers. In this way, designs with aeroderivative refrigerant compressor drivers, like designs with heavy-duty gas turbines in combined cycle, can be applied in a wide range of climates. The new LNG train design offers a choice between simplicity, high efficiency and low CO₂ emissions whilst the concept remains fully scalable between 3 to 6 mtpa.

Floating LNG is complementary to conventional onshore LNG, as it enables tapping into difficult-to-reach off-shore reserves

The export-oriented integrated oil and gas project, Sakhalin II truly opened new areas for innovation. Situated in sub-Arctic conditions, the challenging environment necessitated the pioneering of many new technologies and business solutions.

At the heart of the Sakhalin II development is Russia’s first LNG production plant (shown in figure 1), consisting of two LNG trains, together capable of processing gas to produce a total of 9.6 mtpa of LNG and the offshore export terminal. Shell developed the proprietary Dual Mixed Refrigerant (DMR) process, a two-stage liquefaction process, specifically to help cope with and even exploit the varying ambient temperature of Sakhalin. The LNG project started up in March 2009 producing significantly ahead of projections, and continues to perform well.

To monetise gas from offshore and close-to-shore fields floating liquefaction is being developed. Floating LNG is complementary to conventional onshore LNG, as it enables tapping into difficult-to-reach off-shore reserves. Floating LNG projects are technically feasible, but significant technical
challenges for instance related to full integration of gas production, liquefaction, storage and off-loading need to be addressed. The reduced space and the dynamic motion environment, due to variable met-ocean conditions, requires innovative and breakthrough technologies.

The key dimensions of Shell’s generic Floating LNG concept are 480 x 75 metres, with about 3.5 mtpa LNG capacity plus associated LPG and condensate production, taking total liquid production potential to around 5 mtpa. The Floating LNG design is suitable for a wide range of feed compositions and metocean conditions.

**LNG shipping**

In developing Floating LNG, we not only made use of our experience in liquefaction and in off-shore operations, but also of our track record in shipping. Our expertise in shipping includes feasibility studies, benchmarking, port and terminal advice, technical consultancy, fleet operations and vessel procurement.

At the end of 2009 the world LNG tanker fleet consisted of around 336 vessels. Through our Joint Ventures and direct ownership, we have equity, management or chartering positions in around a quarter of the global LNG fleet. Shell Shipping has been at the forefront of the development of LNG carriers and helped to develop the codes and standards the industry abides by. Our experience extends from the very first LNG vessels through to modern technologically advanced designs.

The majority of ships can carry around 135,000 to 145,000 m³ of liquefied natural gas at atmospheric conditions, in huge, insulated tanks which keep the liquefied gas at -160°C.

As LNG train capacities have increased over time in order to capture the advantages of economies of scale, ship capacities have increased as well. The Methane Princess mentioned earlier had a capacity of some 27,000 m³ of LNG divided over nine cargo tanks insulated with balsa-wood and glass-fibre, in the seventies LNG carrier size increased to around 125,000 m³ and then for many years stayed around 135,000 m³. The Q-Flex and Q-Max LNG vessels introduced by Qatargas in 2008 were a true step-change, these vessels are capable of transporting respectively 215,000 m³ and 265,000 m³ of LNG.

Shell provides ship management and maritime services to a fleet of 14 Q-Max vessels and 11 Q-Flex vessels owned by Qatargas’ shipping company, Nakilat. The agreement covers a full range of services, including staff recruitment, training and operational management of all the vessels.

The developments in shipping follow a similar pattern to the developments in liquefaction, a continuous focus on economics and meeting ever more stringent environmental regulations.
targets is absolutely key. Reducing fuel consumption is a main development area, driven both by cost saving goals and environmental concerns (less fuel consumed means less emissions). Shell actively participates in many industry-wide programmes to improve the environmental performance of its shipping operations. The Shell managed LNG carriers have been awarded Green Passports, which certify the environmental credentials of a vessel and are independently supplied by Lloyd’s Register and Det Norske Veritas, but continuous improvement and development is needed.

The successful changeover from Heavy Fuel Oil (HFO) to Low Sulphur Marine Gas Oil (LSMGO) is such a development. To comply to the European Union Directive 2005/33/EC, which requires all ships at berth in EU ports to reduce sulphur emissions to 0.1 per cent, Shell undertook a detailed study, not only to find the best and safest way to comply with this legislation, but also to meet potential future emission requirements by the International Maritime Organisation (IMO). The evaluation concluded that from the main options evaluated, the switch-over to LSMGO would ensure full compliance while ensuring process safety and personal safety. The primary technical challenge was the application of LSMGO in marine boilers, including high pressure boilers on LNG carriers. In the end many adjustments to the system design and key areas were made to ensure a safe and automated switch-over to LSMGO, to enable the fleet of Shell managed ships to comply as required to the EU directive by 1st January 2010.

Safety has already been mentioned, the LNG shipping industry has a very good safety record with the safety performance of the Shell managed fleet consistently among the best in the industry. The shipping industry works closely together and shares many of their learnings, as for instance was done at the LNG16 conference in Algeria where the results of a joint investigation into the effects of fire on LNG carrier cargo containment systems was presented.

**Conclusion**

The world is changing rapidly, it is not sufficient to do what you have been doing, there is a continuous need to improve. Shell is active through the full LNG value chain, from gas well to burner tip. Our experience has taught us to be passionate about continuous innovation.

It will take technical excellence and continued innovation to push the boundaries of the gas and LNG supply envelope ever further, whilst keeping cost in check. Shell remains committed to work together with its partners and continue with its proud track record of innovation.
No one can say that the natural gas industry lacks challenges. The deep global recession with its sharp and unexpected fall in demand, the increasing pressures to move to low-carbon economies and the potential to exploit massive reserves of shale gas are just three challenges testing our industry's efforts at strategic planning. So, as the world slowly emerges from the economic crisis, where do we stand and what, more importantly, does the future hold for Gazprom and the industry as a whole?

I believe the picture is very positive. Indeed, I am confident that our industry faces a unique opportunity to fuel economic growth and spread prosperity.

Despite the doom-mongers – and thanks to coordinated action across the world – the global economy did not sink into depression. Economic growth is picking up across most parts of the world. So, too, is demand for natural gas. In fact, demand was already back at 2007 levels last year when the financial crisis began seriously to feed into the real economy. As countries recover, it will reach new heights.

Nor has our industry any reason to fear the increased pressures to cut carbon emissions which, despite the failure of the Copenhagen summit, are rightly bound to re-emerge. Indeed, this is a tremendous opportunity if we have the confidence to lead rather than battle actions to reduce emissions and to argue strongly against those who persist in lumping natural gas with other fossil fuels.

Natural gas is not coal or oil. It produces much less carbon for each unit of energy. This makes it the best near- and long-term solution to meet the inter-linked goals of combating climate change and reliably powering economic growth and spreading prosperity. There is, of course, a huge role for renewable energy to play as we move towards a low-carbon world. Also, we are likely to see a new age of nuclear power.

But both renewable and nuclear energy are only part of the solution. They cannot fix the problems on their own. There are question marks about the reliability of wind or solar power since it is not in our gift when the wind blows and the sun shines. Some technologies, although promising, are a long way from development on even a fraction of the scale needed. Nuclear power is still more expensive and comes with its own environmental and security concerns. In contrast, natural gas has proven reserves, is competitive in price and has a modern infrastructure already in place. Burning natural gas instead of coal reduces CO₂ emissions by 50-60 per cent. What is more, new gas-fired power stations can be built quickly, are highly reliable and provide value for money.

We have to have the confidence not to fight against carbon management but to sell natural gas as part of the solution. Without a greater reliance on natural gas, there is little prospect of meeting targets within Europe for a 20 per cent reduction in carbon emissions by 2020. For example, replacing every second coal-based power plant with modern gas-turbine units would be enough to see Europe achieve nearly half of its 2020 emissions reduction target. Reaching this target requires a change of mind-set from governments. It requires government to come up with a specific policy for natural gas.

The rise of shale gas in the US has created expectations of an era of cheap gas and a new global energy balance. It could be, of course, that shale gas will also begin to play a bigger role in meeting energy needs in Europe as has already happened in the US. With seemingly inexhaustible reserves and low transportation costs, shale gas already has a solid share of the US gas market. It is expected soon to make up as much as 14 per cent of the country’s gas production.

This has had a knock-on impact across the world, with less demand for LNG exports in the US. Coupled with the fall in demand due to the global recession, this has exacerbated the imbalance between supply and demand in the spot markets. With large reserves also being found in Europe, some have argued that shale gas poses a major threat to conventional gas producers such as Gazprom. I don’t share these concerns. I believe shale gas reserves will be progressively developed, but only if this can be done in a way which is both environmentally responsible and cost-effective.

Here we are already seeing potential brakes appear on the shale gas revolution. Extracting shale gas requires complex and expensive production technologies than conventional gas. Total well costs can easily be three or four times the cost of a conventional well. According to industry observers, few, if any producers, are making profits when the need to repay interest on the money borrowed to develop fields is taken into account. The result could as well be a price increase of shale gas in the US market.

These price constraints go along with increased pressure on the environmental record of the shale gas industry. The pressures will only increase following the disastrous oil spill in the Gulf of Mexico and heightened public awareness about the environmental consequences of energy exploration.

The US Environmental Protection Agency is already conducting a two-year study into the environmental and human health impact of shale gas drilling. The technology used to release the gas from shale beds uses huge amounts of water, along with potentially harmful chemicals that risk affecting underground aquifers supplying drinking water. While unlikely to halt development altogether, environmental concerns could well slow the growth in development and production. These same concerns are likely to have a bigger impact in Europe which is much more densely populated and which has, in

Putting the ‘shale gas revolution’ into perspective

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general, stricter safeguards for the environment. There are also even bigger hurdles to overcome towards profitability.

Without the need to transport gas across the continent by pipeline, shale gas produced in Europe is potentially less costly than natural gas. The reserves are very large. According to the IEA, the recoverable shale gas reserves in Europe equal 16 trillion cubic metres or just a little bit less than half of Gazprom’s known reserves. But preliminary exploration results suggest that different geology may prevent the simple transfer of American technologies across the Atlantic. ExxonMobil, for example, stopped working in the Mako Trough field in Hungary following two hydraulic fractures and disappointing results.

Even where these problems can be overcome, production costs seem likely to remain significantly higher than in the US. ConocoPhillips believes that, with geological characteristics similar to those of the Barnett field in the US, project profitability in Northern Poland can be achieved at the gas price level of US$318 per mcm compared to US$140-180 per million cubic metres in the richest sections of shale basins in the US.

There is the added complication that European land owners are likely to be less enthusiastic about the development of shale gas reserves. Unlike in the US, they do not own the mineral rights of their land and cannot claim a portion of the revenue from any future gas sales. For all these reasons, it is unlikely that we will see serious production of shale gas before 2015 with little chance of it providing direct competition to imported pipeline gas until 2020 at the very earliest.

And let’s not forget there are abundant conventional gas fields in Russia which are linked through long distance pipelines to European consumers. So why should Europe switch to more expensive and ecologically questionable unconventional gas production? At Gazprom we are not against shale gas. We believe shale gas could be a useful partner to meet growing energy needs. The development of large shale gas fields is likely to see more countries place much more importance on gas in meeting future energy needs, as is already happening in China. The result is likely to be a major boost for gas as a clean fuel in the global energy mix.

Last year, the US Potential Gas Committee increased US gas reserves by almost 50 per cent, almost entirely on the basis of shale gas. If we see a similar reassessment in other countries, natural gas will increasingly be recognised as the plentiful and widely accessible resource. This will lead to much greater emphasis – and investment – to ensure gas is used as the primary fuel for power plants and for transport.

So, we should be enthusiastic partners in the drive to reduce carbon emissions. Natural gas fits the low carbon bill. We should, too, welcome rather than fear technological advances enabling us to harness new reserves of gas in new ways. If we do, I believe the long-term future for natural gas is bright. It is why Gazprom will continue to make the investment needed to help meet the needs of consumers, industry and economies for clean, affordable and reliable supplies of energy for many decades to come.