lacklustre economic performance these past four years will be a top priority for the re-elected President as will be energy supplies.

Even though it recently achieved oil independence, Brazil imports just under half of its natural gas by pipeline. The chief supplier is Bolivia with a small amount from Argentina. In the 1990s, the Brazilian government reinforced the country's hydroelectric power grid with plants fuelled by natural gas, and the country has the world's second largest fleet of NGVs after Argentina (1.46 million and 1.23 million vehicles respectively).

Now with additional supplies from Bolivia uncertain, Brazil must increase domestic production and seek new natural gas supplies. Brazil expects its gas consumption to double by 2010 and is studying the feasibility of building two LNG import terminals. Petrobras expects to double its exploration spending over the next five years to make up for the lost Bolivian imports it originally expected from the expansion of the pipeline. Its five-year plan has gas production hitting 70 mcm/day in 2011 up from 27.5 mcm/day in 2006.

Brazil has failed to attract foreign capital for natural gas development due to a number of factors. Petrobras still has too much market power, fully competitive regional gas markets with broad participation and ample liquidity do not yet exist, gas prices are set rather than negotiated and there is a lack of third party access to the transmission infrastructure. Moreover, unwieldy labour, tax and social security laws make the business environment costly and bureaucratic.

● Argentina: The ins and outs of the gas trade

Economic activity in Argentina is recovering across all sectors as the country rebounds from the catastrophic crash brought on by the collapse of the fixed exchange rate in 2001-2002. Inflation has been relatively controlled, growth is back, interest rates have fallen and the economy has grown more than 8% for each of the past three years.

The economic collapse had also had a severe impact on the energy industry. Fearing the political impact of large tariff increases, the government of

Filling up with CNG at a Petrobras service station in Rio de Janeiro. Brazil has 1.23 million NGVs and 1,300 stations where they can refuel.

Argentina's gas resources include the world's most southerly production facility. This pipeline in Tierra del Fuego collects gas from the offshore Carina and Aries fields operated by Total in a consortium with Pan American Energy and Wintershall.

then President Eduardo Duhalde converted energy prices to pesos at par and froze them. Utility tariffs had been fixed in dollars. Prices today are approximately $0.50 per Mmbtu versus approximately $1.50 per Mmbtu before the devaluation. At the time, he said he planned to renegotiate the contracts of the utilities, but what was supposed to be an emergency measure became an energy policy. The consequences of the new pricing policies were disastrous for the industry.

For most of the utilities, the frozen tariffs covered only their operating costs, so investment stalled as the economy expanded and energy demand grew. This has resulted in widely predicted shortages. Energy prices are at around one-third of the level required for a reasonable return on investment, and many of the electricity companies are in default on their dollar debts. Energy shortages during the past three years have forced the government to lower voltages on the national grid, cut electricity exports to Uruguay, and ration supplies to the biggest industrial users.

President Néstor Kirchner has quietly moved to increase some tariffs, by 35% or so for industrial users of electricity and gas, and promised gas producers that prices would be "normalised" by the end of 2006. He has also launched a plan for new state gas and electricity companies. The investments required to ramp up gas exploration and ease pipeline bottlenecks could exceed $500 million a year.

On October 19, 2006 Bolivia agreed to sell Argentina natural gas worth more than $17 billion over the next 20 years. Facing increasingly serious energy shortages at home, Argentina has no option other than to pay Bolivia higher prices and is pushing a pipeline project to expand access to those supplies. Argentina currently imports

NGC – Partnering with Nature and Communities

"A thing is right only when it tends to preserve the integrity, stability and beauty of the community; and the community includes the soil, water, fauna and flora, as well as the people." **ALDO LEOPOLD**, A Sand County Almanac, 1949

Our principles

NGC believes that the goals of economic well-being and environmental sustainability can be pursued side by side. With this belief, NGC has adopted statements of national interest and health, safety and the environment as major guiding principles which have inspired our strong environmental and social ethos. This ethos is demonstrated by NGC's 10-year Reforestation Plan, which supports our No Net Loss Policy for Forest Resources and aims to restore a sustainable balance between nature and development.

Our programme

This 10-year period will mark the reforestation of 315 hectares of critically-degraded forests in three forest conservancies in Southern Trinidad. The ten-year period will be used not only to plant trees, but to replace any seedlings that may have died during the first couple of years with healthy specimens. Seedlings will also be maintained and monitored. After the 10-year period, a forest of unfelled trees will be presented intact to the Forestry Division of the Ministry of Public Utilities and the Environment.

This reforestation programme arose out of requirements of the Certificates of Environmental Clearance for the construction of NGC's 76.5 kilometre, 56-inch Cross Island Pipeline and Beachfield Upstream Development, a project which involved the construction of a 36-inch pipeline as well as a new slug catcher. The CECs required that NGC reforest an area totalling at least the maximum area of forest cleared during construction. NGC also applied the concept to the construction of the Union Industrial Estate, though this project's CEC did not have a reforestation requirement.

Our plan

- This programme takes place within communities in which we carried out our activities for the construction of the 56-inch, 76-kilometre Cross Island Pipeline, the 36-inch BUD Pipeline and the Union Industrial Estate.
- A social or community forestry approach has been adopted and will involve the local communities in the management, use and protection of forest resources.
- This reforestation will also incorporate an agro-forestry component, allowing community groups, who will be tending to the plantation of forest trees, to plant approved food crops such as tomatoes and pumpkin for subsistence or their own economic gain.
- This reforestation will have spin-off effects including providing food and shelter for wildlife and contributing to soil conservation.
- This programme will, therefore, have positive social effects by providing a basis for community development, creating jobs and fostering an appreciation of our natural resources within the community.

Our progress

Since the programme's inception on World Environment Day, June 5, 2006, the cutting of lines and planting in four of the five blocks of trees has begun. The trees selected for the reforestation are tropical wood species and fruit-bearing species, approved by the Forestry Division. The following table gives a summary of the progress as of December 2006.

Our Pledge

As a national company, NGC is committed to deriving the maximum value of natural gas for the benefit of Trinidad and Tobago. In partnering with the Forestry Division of the Ministry of Public Utilities and the Environment and our local communities, NGC is illustrating its commitment to our national objective: ensuring that development does not happen at the expense of our environment or our people.

This commitment guides our Reforestation Programme and allows us to contribute to the conservation and preservation of our forests for the enjoyment and benefit of our country's future generations.

ITEM	MAYARO (Victoria/Mayaro Forest Reserve)	EDWARD TRACE (Victoria/Mayaro Forest Reserve)	ROCHARD DOUGLAS (Rochard Douglas Forest Reserve)	GRANT'S TRACE (Morne L'Enfer Forest Reserve)	LA BREA (Morne L'Enfer Forest Reserve)
Cutting lines (m)	12,810	13,885		14,500	12,018
Planting:					
Crappo	205	150	**Scheduled**	300	180
Columbian Cedar	770	913	**for 2007**	858	1064
Mahogany	300	200		470	340
Local Cedar	500	750		380	293
Apamate	300	175		300	200
Pommerac	50	25		128	40
Cashima	10				
Total no. of seedlings planted	2135	2213	**Scheduled for 2007**	2436	2017
Area planted (ha)	7.8	7.9	**Scheduled for 2007**	8.8	7.3


REFORESTATION: AN NGC IMPERATIVE
As we continue our role in Trinidad and Tobago's development, building a comprehensive natural gas pipeline network and developing industrial estates, we have been unable to avoid clearing some forested areas.
To give back, NGC has adopted a "No Net Loss Principle" regarding forest reserves, committing us to replace at least the equal of forest cleared.
Already, we have begun a ten-year project that will reforest degraded areas in the Rochard Douglas and Mayaro/Victoria Forests and the Morne L'Enfer Forest Reserves.
In all, over 315 hectares will be replanted to restore these forests to the way Nature intended.
THE NATIONAL GAS COMPANY
OF TRINIDAD AND TOBAGO LIMITED

7 mcm/day and the agreement between Bolivia's YPFB and Argentina's Enarsa calls for a gradual increase of gas export volumes to Argentina to 27.7 mcm/day by 2010. The $5 per Mmbtu export price set in the bilateral agreement was fixed until the end of the first quarter of 2007, and the price now fluctuates according to the market.

Argentina's agreement to this price structure puts added pressure on Brazil to agree to increase the price it pays for Bolivian gas. The agreement between Argentina and Bolivia will also have implications for Chile, more than a third of whose electricity generation is gas-fired, all with gas imported from Argentina.

● Chile: Seeking alternative gas supplies

March 11, 2006 saw the inauguration of Michelle Bachelet as the first female President of Chile. Since the mid-1990s the economy has enjoyed almost 6% growth a year but with only small deposits of coal, oil and gas, energy supplies remain a top priority for the new administration.

Chile is heavily reliant on Argentine natural gas for two-fifths of its electricity. Since the mid-1990s, around $6 billion has been invested in cross-border pipelines, gas-fired power plants and the conversion of industries and homes. Energy security became a major concern in Chile in 2004 when Argentina, hit by an energy crisis, restricted exports of natural gas without consultation with the Chilean government. For two weeks in November 2006 a workers' protest interrupted deliveries to Chile further casting doubt on Argentina's reliability as a supplier.

With gas accounting for 25% of the country's primary energy consumption, Chile is pushing conservation and has started construction on an LNG import project at Quintero, where it hopes to receive gas from Indonesia and Trinidad to serve industrial consumers in the north. The $400 million facility, due to come into operation in 2008, is being built by BG Group in partnership with three gas buyers: ENAP, Chile's state oil company; Metrogas, the country's main natural gas

Trinidad and Tobago is a major LNG exporter (ranking number 6 in 2005 with 14 bcm) and could supply Chile in the future.

distributor; and the Chilean power generating subsidiary of Spain's Endesa. Peru has scrapped a plan to export gas to Chile via a possible pipeline due to the distance and terrain.

● Colombia: New prospects?

In May 2004, Petrobras teamed up with ExxonMobil and Colombia's state-owned company Ecopetrol to explore Tayrona, an area of more than 4.4 million hectares off Colombia's northern coast. Petrobras is so optimistic that there is oil and gas below the Colombian portion of the Caribbean Sea that it plans to expand its operations there. Indeed, its investments in Colombia reached a total of $130 million in 2006, four times as much as in 2005.

Rafael Correa celebrates his victory in Ecuador's Presidential elections.

● Ecuador: Set to renegotiate contracts

No one can accuse Ecuador's politics of being dull having elected in November 2006 its eighth president in 10 years. The new President, Rafael Correa, who won 68% of the votes cast, faces pressure from the poorer voters who have not shared in the limited economic development of recent years. Mr Correa's rise points to how varied, and persistent, the leftist groundswell has become in Latin America. His promises to restructure the country's debt, possibly in an Argentine-style, forced renegotiation, reject free trade and World Bank and IMF polices, together with the distrust he has expressed of transnational corporations, have resonated well with many people in this impoverished country.

Trained in Belgium with a PhD in economics from the University of Illinois, and a former finance minister and university professor, President Correa has pledged to renegotiate contracts with oil companies in order for the government to gain a greater share in the profits. If the companies do not like it then expect the state-owned Petroecuador to take over the oil fields.

Unlike Bolivia's blanket nationalisation, Ecuador's moves against the energy industry have so far been specific to Occidental Petroleum. In May 2006, Ecuador revoked Occidental's contract and took over its operations after accusing it of transferring part of an oil field without authorisation. Occidental says it has complied with its obligations and still hopes to settle. Repsol-YPF is now Ecuador's biggest producer.

Hopefully President Correa will prove to be more pragmatic in office than his harsh campaign rhetoric suggested. His biggest obstacle is likely to be the newly-elected legislature controlled by his opponents. It remains unclear if he would like to be a strident nationalist in the mould of Hugo Chávez or a centre-left pragmatist like Lula da Silva. Meanwhile, the challenge for Petroecuador will be to maintain the capital investment necessary to keep the oil flowing.

● Venezuela: Pipe dreams

Although Venezuela has the largest gas reserves in South America (4.32 tcm), they are relatively undeveloped. Over the years, gas has taken a back seat to petroleum in the country, which is one of the world's leading oil exporters.

Recognising this problem, the Chávez government had made laws more attractive for investors in gas. That contrasts sharply with the blunt measures that wrested control from foreign companies producing oil. However, recent announcements of nationalisations in the electricity and telecommunications sectors were coupled with a declaration that "greater control" would be sought over natural gas projects. At presstime it was unclear how the gas situation would develop.

Chevron has already found enough gas in the Plataforma Deltana area in the east for Venezuela to begin commercial exploitation. Chevron was proposing to export LNG to the US and European markets through a $5.6 billion complex that the state oil company, Petróleos de Venezuela (PdVSA), plans to build outside Güiria.

However, PdVSA also wants the complex to feed a proposed $20 billion transcontinental pipeline and says those plans are a higher priority than exporting LNG. The pipeline would traverse the country from Puerto Ordaz to Santa Elena de Uairén near the Venezuelan/Brazilian border, fork towards north-eastern Brazil, and then extend from Brasilia to Rio de Janeiro, Uruguay, and finally, Argentina. Though Venezuela could reap higher profit margins by exporting LNG to higher-price markets like the United States, Venezuelan officials acknowledge that is not their goal.

Staff at work on an oil production platform on the shores of Lake Maracaibo – up to now gas has taken a back seat to petroleum in Venezuela.

"It's not that the economic part doesn't matter," said Ángel González, General Director of Exploration and Production at the Ministry of Energy and Petroleum, "but it's really not the most important part of this project." Government officials have yet to disclose details on its routes or costs, saying that technical teams are performing preliminary studies. The proposed pipeline has generated political and environmental controversy at home and abroad and it is not clear that President Chávez can muster long-term support in South America for a pipeline that would take at least a decade to complete.

Conclusion

The mixture of politics and energy has always been a volatile one and is not unique to South America. The recent surge in populism has reinforced uncertainty over gas supplies, which are a major headache for the continent's booming economies.

One solution is to look for new sources outside South America and it appears some countries will soon join the international race for LNG supplies. For the southern states the best alternative for supply remains Bolivia. Hopefully the realities of governing and a grudging recognition that Bolivia must cooperate with the very investors that are despised symbols of foreign influence will move the government closer to the political centre as they have in Brazil and Argentina.

Still, as long as the benefits of economic growth flow disproportionately, South America will remain a fertile ground for politicians who promise strong government intervention and a retreat from market economics. In the meantime, dreams of energy self sufficiency and an integrated natural gas market have been postponed as the gas industry adapts and reviews it options.

Terence H. Thorn was the Chairman of IGU Working Committee 9 in the 2000-2003 Triennium and is President of JKM Consulting in Houston, Texas. He may be contacted at tthorn@txthorns.net.

IS IT POSSIBLE TO CROSS THE WORLD IN 730 KILOMETERS?

The Camisea gas pipeline in Peru is a huge project at worldwide level.

Starting in the largest tropical jungle in the earth with a challenging terrain, it goes across the amazing snow covered Andes bringing the natural gas to the Peruvian desert coast.

If Peru has all world geographies and climates, TgP must have used all the knowledge to live within them.

Therefore, to the question above we answer yes: it was possible to build this 730 kilometers pipeline system and we are proud of it.

A project that once was a dream now is a way to carry clean energy to generate development for the people.

TgP Transportadora de Gas del Perú

WOC 1 Studies Current Gas Production and Supply Issues

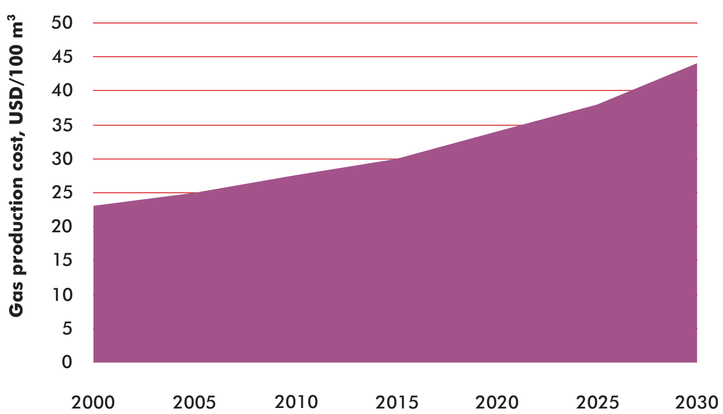
By Vladimir Yakushev and Sergey Leonov

During recent decades the gas industry has developed dramatically around the world. But as demand for natural gas grows so do the costs of exploration and production (*see Figure 1*). New, often remote and hard-to-extract gas deposits have to be developed, while it is also important to search for and develop unconventional sources of gas. Moreover, updating and refining the technology used to search for these resources and extract them requires continual investment.

Challenges are also faced in the international supply chain as the distances between sources and markets increase. The large markets in Europe and North America are becoming the main gas importers, while new players are coming onto the scene in Asia and Latin America. There needs to be continuing development of gas processing and transportation technologies such as LNG, gas-to-hydrates, gas-to-wire, gas-to-liquids and compressed gas to reduce transportation costs and enhance flexibility in the global gas supply chain.

BELOW
Figure 1.

FORECAST INCREASE IN PRODUCTION COST OF NATURAL GAS TO 2030.



Source: WOC 1 data, 2003.

On the environmental side, issues connected to CO_2 sequestration and methane emissions have been on the agenda for a long time and are an important aspect of WOC 1's work. The development of technologies such as CO_2 injection into productive reservoirs not only helps to reduce harmful ecological consequences, but also to lower industrial expenses by increasing gas extraction volumes.

In the current 2006-2009 Triennium WOC 1 is focusing on these and other problems faced by the gas industry. The Committee will gather and thoroughly analyse new information on these issues, and will also evaluate potential avenues for the further development of the role of natural gas in the world economy.

Developing conventional gas resources

With regard to the development of new conventional gas resources, WOC 1's activities cover several areas. One of these is the development and production of additional resources of natural gas from known deposits in so-called "mature" gas-bearing regions. Here, for example, it is possible to extract gas from deeper levels, upgrade existing technology and develop new methods to increase delivery rates.

WOC 1 also plans to monitor the search for new gas deposits in these regions. Although the discovery of new large gas fields in these regions is improbable, the development of average and even small fields, taking into account proximity to main consumption centres and the presence of developed gas-production and gas-transportation infrastructure, can be economically viable. In The Netherlands, for example, a number of small gas deposits have been developed for many years in tandem with the development of the giant Groningen field. This policy has appeared to be very successful, the combination of newly discovered and developed gas volumes providing high security of supply.

The potential of global natural gas production depends not only on proven reserves, but also on the implementation of new development projects and the creation of new transportation routes to bring gas to market. In this context, resources in the Arctic region and deep-water gas deposits show huge potential for the growth of world reserves. Even at this current early stage of exploration maturity, the Arctic region (including the Arctic shelf) has already seen the discovery of such giant gas fields as Bovanenkovo, Shtokman and Ormen Lange.

However, the development of resources in the Arctic region and deep-water fields entails many technological, economic and environmental problems. These include remoteness from the continent, significant sea depths, high tides, frequent storms, drifting ice and complex climatic conditions. Engineering and geological factors, such as the properties of the seabed subsurface and bottom shape, can also complicate the development of deposits. Great water depth,

In The Netherlands a number of small gas deposits have been developed for many years in tandem with the development of the giant Groningen field.

The Arctic region has already seen the discovery of giant gas fields such as Ormen Lange whose gas processing plant at Nyhamna is pictured.

negative bottom temperatures and gas hydrates in overlying sediments represent additional difficulties

All this requires the development of new techniques and technologies, which demands not just huge levels of investment but a high level of international cooperation. Joint development projects and the sharing of experience are crucial in aiding the modification of existing techniques and technologies and the development of new ones. Addressing this area is one of IGU's (and WOC 1's) key tasks in the current Triennium.

With a strong commitment, the significant gas resource potential of the Arctic region and deep-water gas deposits combined with progress in exploration technologies should make their development economically viable in the near future.

Research into submarine gas hydrates is part of the work of the international Ocean Drilling Programme, which uses the scientific research vessel *JOIDES Resolution*.

Developing unconventional gas resources

The potential to increase natural gas reserves by tapping unconventional gas sources arouses great interest all over the world. Unfortunately, levels of knowledge regarding the geological parameters of major parts of these unconventional resources leave much to be desired.

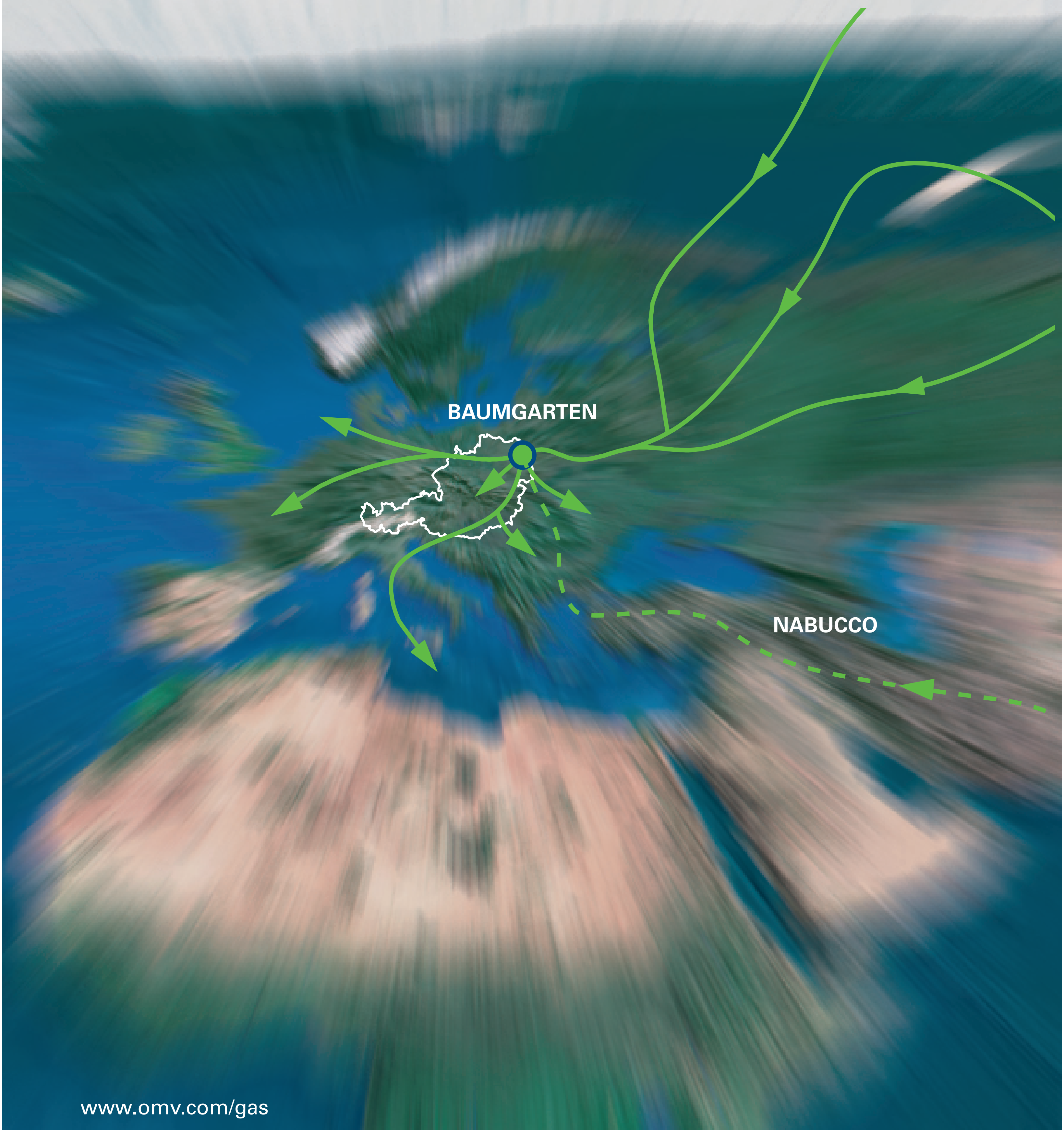
Among unconventional gas sources of industrial value, the wide occurrence of gas hydrate deposits and their huge reserve potential serve as weighty arguments for developing them as an alternative energy source.

Submarine gas hydrates, which possess much greater resource potential than continental ones, are of particular interest around the world. Moreover, submarine gas hydrate exploration has become much more effective recently owing to developments in research techniques in a number of areas. Countries such as China, India, Japan, Germany, the UK and the USA are involved in scientific programmes, which are funded by both governments and petroleum companies.

The main problem in considering the industrial development of continental gas hydrate deposits is the need to develop a new and complex exploration method encompassing a combination of borehole, geophysical, laboratory and geochemical techniques. Also, existing methods of gas hydrate production have a number of serious restrictions due to cost and limited applicability in various geological situations. New and improved approaches are required to make them viable.

As regards other unconventional gas sources, coal-bed methane (CBM) and gases in tight reservoirs are notable.

Despite significant reserves of CBM, the technologies needed for the industrial production of this form of gas differ from those used in conventional natural gas production. The only example of successful CBM production and delivery to the gas pipeline system is in the USA, which is due to the unique geological structure of the San Juan Basin. However, there is a general tendency



OMV keeps natural gas moving to where it's needed

Every year we transport 45 billion m3 of natural gas via the European gas hub in Baumgarten, Austria, to neighboring countries such as Germany and Italy.
With the international NABUCCO gas pipeline project, we are also playing a significant role in assuring Europe's future gas supply.

Move & More. OMV

The only example of successful CBM production and delivery to the gas pipeline system is from the San Juan Basin in the US states of Colorado and New Mexico.

towards cost reductions in CBM production which should make it more viable in a number of coal-bearing regions in the near future.

Producing gas from tight reservoirs is usually complicated by low reservoir permeability. Abnormal pressures are also often widespread in such reservoirs. This usually increases their resource base, but the presence of heavy fractions of condensate and oil reduces the volume of recoverable reserves. Exploration and production of gas from tight reservoirs demands significant volumes of drilling work and the application of the newest technologies, due to low rock permeability.

The HT/HP conditions of deep gas reservoirs (more than 4500 metres in depth) mean that they contain considerable hydrocarbon resources. However, as development of these resources is expensive, only large deposits with relatively high permeability appear to be profitable for gas production. Moreover, there is a lack of geological data to forecast the existence of large deposits at such depths in the majority of sedimentary basins. Pre-mountain depressions characterised by high sedimentation rates and deep intermediate complexes offer the greatest promise. Development of deep deposits requires the creation and implementation of new technologies, the use of high-cost materials and substances and high power inputs. The prospect for the development of such reservoirs and gas sources is highly dependent on the market price of natural gas.

Gas from shallow deposits (less than 500 metres in depth) has considerably smaller resource potential. However, even in the current stages of exploration maturity it can be easily used for local gas supply due to its closeness to the surface, which simplifies its extraction.

Lastly, reserves of aquifer gas have the prospect of being developed in the long term. Two methods are possible for this type of resource: the development of prospective water-bearing layers, as independent sources of gas; and the extraction of associated water-dissolved gas when developing conventional aquifer gas deposits. In the latter case the basic development problem concerns the very low recovery rates of such gas, accompanied by the huge volumes of associated mineralised water which are needed to prevent environmental contamination.

Objective view for WGC2009

WOC 1's studies of trends and problems in the exploration, production and delivery to the consumer of natural gas build on the solid work done in previous Triennia. The broad representation of various countries and companies on the Committee should give an objective view on developments in the upstream sector of the gas industry in the near- to mid-term future. These developments will be reported in full at the 24th World Gas Conference in Buenos Aires in 2009.

Vladimir Yakushev and Sergey Leonov from VNIIGAZ, the Scientific-Research Institute for Natural Gases and Gas Technologies of Gazprom, are respectively the Chairman and Secretary of WOC 1.



IT TOOK US TWELVE YEARS TO PRODUCE 100 BCM OF NATURAL GAS
WE WILL PRODUCE ANOTHER 100 BCM IN LESS THAN FOUR

NOVATEK

OAO NOVATEK is Russia's largest independent gas producer, and the second-largest producer of natural gas in Russia. Our proved natural gas reserves rank among the largest oil and gas companies globally and third among oil and gas companies in Russia.

All of our fields are located in the Yamal-Nenets Autonomous Region, the world's largest natural gas producing region, accounting for over 90% of Russia's natural gas production and approximately 20% of the world's natural gas production. All of our natural gas is sold domestically in more than 30 regions where we supply some of the country's largest power generation and industrial companies. In 2005, we produced approximately 4% of Russia's total natural gas output and supplied roughly 7% of the nation's domestic demand.

Launched in 2005, our wholly-owned Purovsky Gas Condensate Processing Plant is an integral part of our hydrocarbons' value chain. The plant has the capacity to produce 1.6 million tons of stable gas condensate and 400 thousand tons of LPG per annum. The commissioning of the plant has proved a vital link in our mid-stream operations allowing us full control over our processing needs, enhancing the quality of our liquid products and providing access to new marketing channels including the delivery of stable gas condensate to US and European markets.

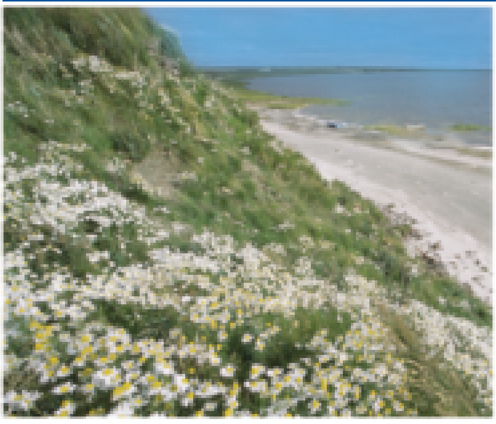
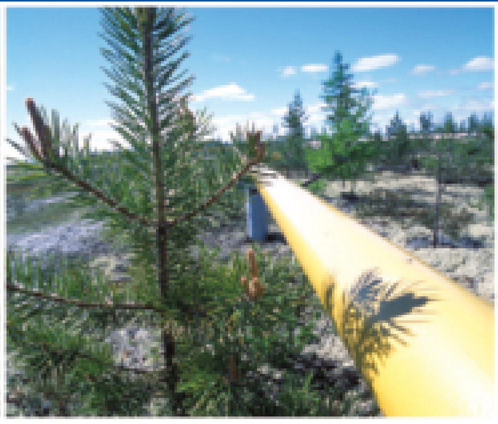
We have ambitious plans to diversify our business by becoming both a leading independent natural gas producer and an active player in the processing, petrochemical and power generation sectors.

Our strategy is to leverage our competitive strengths to increase hydrocarbon production on a sustainable and profitable basis, while operating in a socially and environmentally responsible manner. Specifically, we intend to:

- Substantially increase our production of hydrocarbons, particularly natural gas
- Maintain our low cost structure
- Capture maximum margins on natural gas and liquids sales
- Prove-up our resource base

OPERATING HIGHLIGHTS

2005 Consolidated Production	
Natural gas	25.2 bcm
Crude oil and Gas condensate	2.6 mm tons
Total	186 mm boe
Reserve Base	
Proved	4.6 billion boe
Proved plus Probable	7.4 billion boe
Reserve Replacement Rate	
2005	311%
Three-year average	232%
Reserve-to-production life	25 years


Norway Addresses CO_2 Concerns

By Sigve Apeland

Carbon dioxide is the most significant of the greenhouse gases and looking for ways to reduce emissions is a key issue for all sectors of the energy business. Norway is a trailblazer in this area having inaugurated the world's first commercial-scale carbon sequestration project at the Sleipner West gas field back in 1996. Here, the leader of IGU's Study Group 3.3 reports on recent work by the state-owned Norwegian companies Gassco, Gassnova and Petoro evaluating the use of CO_2 for enhanced oil recovery (EOR).

At first sight using CO_2 for EOR seems like the perfect solution to meet environmental challenges, as well as increasing access to petroleum resources in a world hungry for energy. But there are significant challenges that need to be met in order to realise this potential in offshore oil fields.

CO_2 injection can increase oil production from reservoirs that have suitable characteristics by between 3% and 15% of the original oil in place. How much production can be increased depends on to what extent other EOR methods (water, gas or chemical injection) have been used prior to utilising CO_2, and whether CO_2 can be "routed" through the reservoir as planned, resulting in an "optimal" mix of CO_2 and oil.

Once the challenges related to the reservoir itself have been addressed, however, there are still significant hurdles in relation to technical, commercial and regulatory issues that need to be overcome in order to use CO_2 for EOR offshore.

In North America there are examples of reservoirs of more or less pure CO_2 which are used for the purposes of EOR, but sourcing CO_2 is more complex if no natural sources are available. It can be captured from the flue gas emitted from, for example, gas- or coal-fired power plants, or it can

ABOVE AND OPPOSITE Natural gas in the Sleipner West field in the Norwegian sector of the North Sea has a 9% CO_2 content while its export specification calls for a maximum content of 2.5%. The excess CO_2 is extracted, compressed and injected into a saline aquifer.

be extracted from fossil fuels in a de-carbonising process. Both processes require the establishment of large and capital-intensive facilities on a scale that has not yet been tested anywhere in the world. As an example, a facility for the removal of CO_2 from a 400 MW gas-fired power plant would need to have approximately 10 times the capacity of the world's largest current CO_2 capture facility.

When using CO_2 for EOR, it will eventually follow the oil into the production wells, meaning that a significant amount of the CO_2 will have to be separated and re-injected into the reservoir. Ultimately, the intention is that as much as possible of the accumulated injected CO_2 will be left in the geological formation on a permanent basis, which means that we need to be certain that no CO_2 leakage occurs.

The remainder of this article will elaborate on the issues introduced above, and give a summary of the conclusions from the work that has been done.

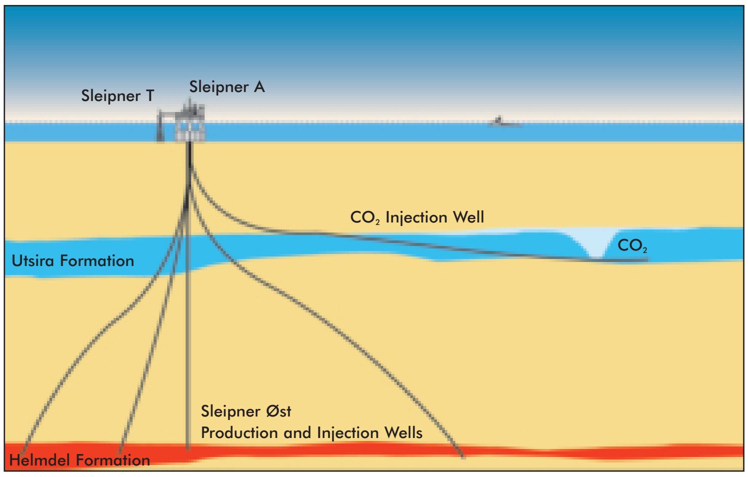
Scope of study

Earlier studies found technical potential for using CO_2 for EOR in oil fields on the Norwegian Continental Shelf (NCS), but drew different conclusions in relation to the economics of CO_2 value chain projects. In January 2006 the state-owned NCS gas transportation operator Gassco received a mandate from the Norwegian Ministry of Petroleum and Energy to initiate a project to identify:

- the potential for the use of CO_2 for EOR in different oil fields on the NCS;
- capture technology and CO_2 sources (both in Norway and abroad); and
- alternative transportation methods for the CO_2.

Based on the identified oil fields, CO_2 sources and transportation methods, costs and income were to be identified and the potential for establishing a commercial basis for the defined CO_2 value chains was to be evaluated.

All analyses were performed at a pre-feasibility level, which means that uncertainty regarding technological qualification and economic results were not formally quantified.



EOR potential

CO_2 has characteristics that allow it to mix with the oil in the reservoir. The oil/CO_2 mix is smoother than pure oil, the CO_2 having a "soap effect", washing the oil/CO_2 mix out of the pores of the reservoir formation. The extra potential for oil production depends on which recovery methods have been used before the introduction of CO_2 to the reservoir, which alternative EOR methods are relevant, and what conditions for CO_2 injection are present (including how many CO_2 injection wells it may be cost efficient to use).

CO_2 injection is a so-called tertiary recovery method for oil production. During primary recovery, the natural pressure in the reservoir is used to drive the oil into the production wells. As the natural reservoir pressure drops, secondary methods such as injection of water or natural gas (which do not mix with oil) are used to maintain the reservoir pressure, driving the oil in the direction of the production wells. Tertiary recovery methods use effects other than pressure to increase oil recovery. Examples of this are thermal recovery, in which steam is used to lower the viscosity of the oil, and chemical injection, where one of the aims may be a reduction in the surface tension of the oil; both techniques have the purpose of making it easier for the oil to flow through the reservoir formation.

NORWEGIAN FIELDS SUITABLE FOR EARLY CO_2 VALUE CHAINS

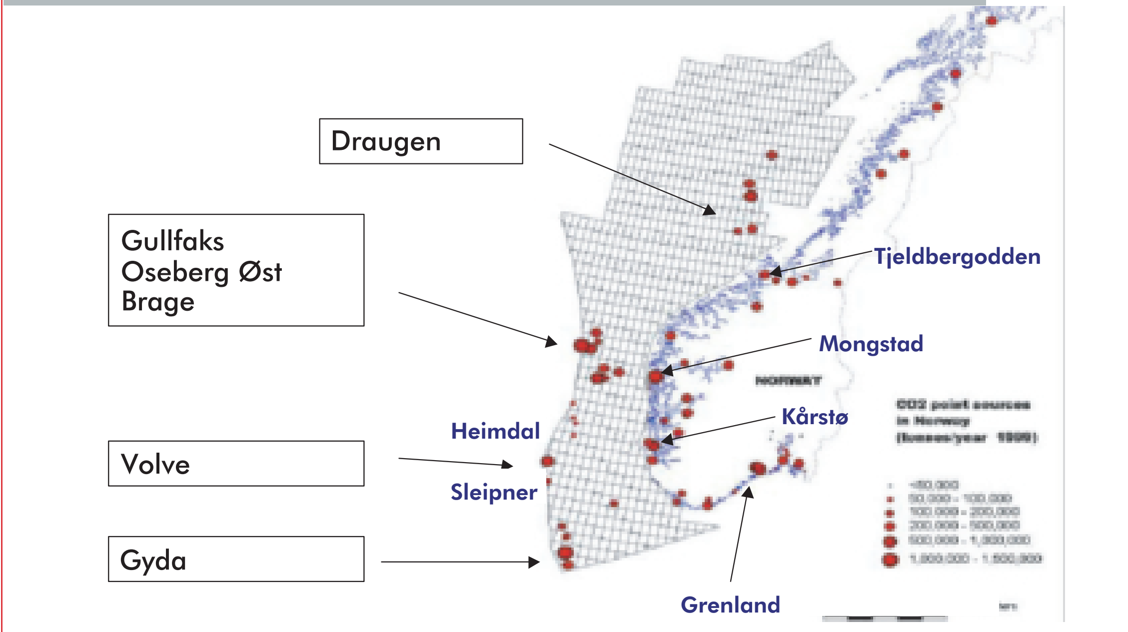


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Figure 1.

In the NCS secondary recovery methods are used extensively, resulting in a lower potential for tertiary methods to be effective than in regions where secondary methods are less prevalent, one example being onshore oil fields in arid regions lacking available water. In the study, which only looked at offshore oil fields, increased recovery rates of approximately 5% of original oil in place were used. Higher recovery rates can be expected for onshore oil fields as the significantly lower cost of drilling injection wells allows for more optimal injection of CO_2 into the reservoir formation.

● Need for production modifications

Introducing CO_2 into the reservoir, and thus also into the well stream of the production wells, implies two challenges as regards the production and processing facilities. First, the mix of CO_2 and water is highly corrosive, which means that those parts of the processing facilities that are in contact with the CO_2 need to be evaluated with respect to corrosion resistance. For facilities that have been designed without CO_2 injection in mind, it is likely that significant sections of the steel would need to be replaced.

Secondly, introducing CO_2 to the well stream means that the amount of gas (natural hydrocarbon gases plus CO_2 in the gaseous phase) increases. If the existing equipment for the handling of gas (e.g. separators) in the facilities does not have the capacity to handle increased amounts, it will need to be replaced. Moreover, CO_2 added to the total gas produced changes the mole composition of the gas mix, and if produced gas is used in gas-fired compressors, these might have to be replaced or modified.

In summary, the study identified that there was a need for modifications to each of the evaluated offshore production facilities in the range of €200-600 million.

● CO_2 capture

The oil fields identified as suitable in the study (see *Figure 1*) were calculated to need in the range of 1 to 5 million tonnes per year of CO_2. Capture of CO_2 on this scale requires facilities that have capacities far beyond any that exist today.

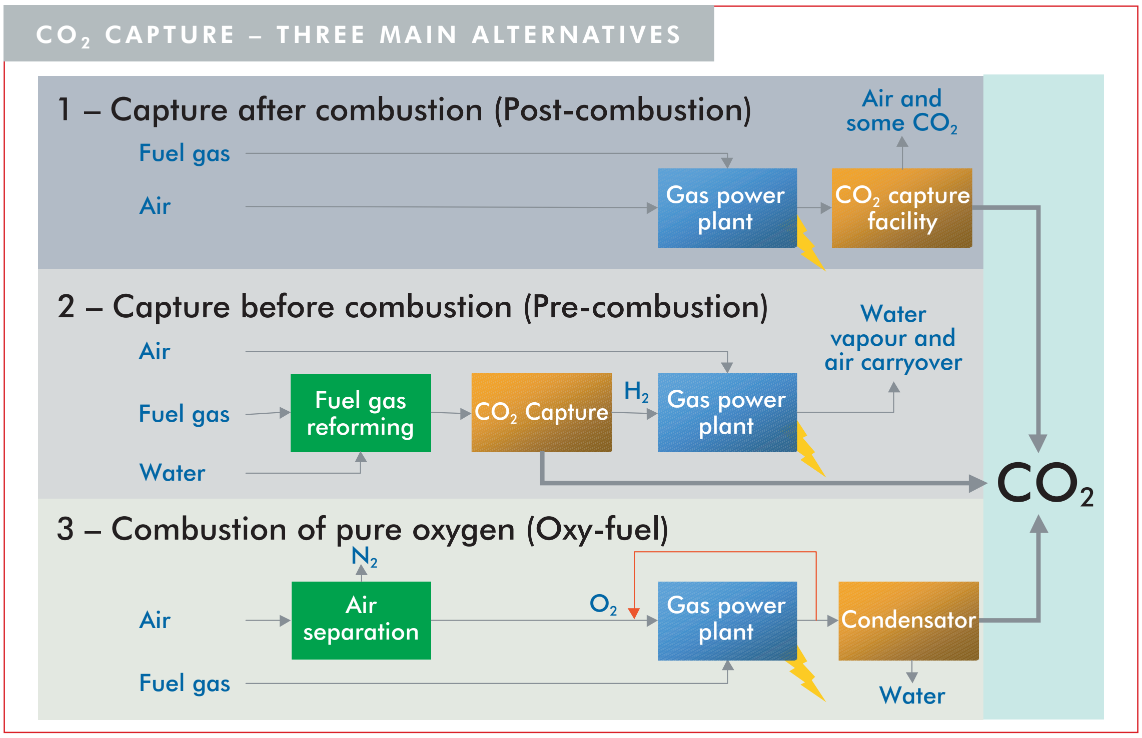

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Figure 2.

In general, there are three methods for large-scale CO_2 capture that can be evaluated in this context (*see Figure 2*):

- Post-combustion: the emissions (flue gas) from the source are directed into a capture facility, for example an amine plant, where amine is saturated with CO_2 in an absorber, the saturated amine/CO_2 is led to a stripper in which the CO_2 is removed from the amine by adding heat, and then the regenerated amine is returned to the absorber.
- Pre-combustion: the fossil fuel is de-carbonised, resulting in CO_2 and H_2, where the hydrogen is used as an energy source, for example for a power plant.
- Oxy-fuel: nitrogen is removed from the air using the resulting (almost pure) oxygen in the combustion process with the fossil fuel. This will reduce the net volume of flue gases, but significantly increase concentrations of CO_2 in these flue gases.

The scope of the study included existing and possible future sources. For existing sources post-combustion CO_2 capture was assumed, since this is the only relevant method that might be used when installing capture of CO_2 after building the source itself. Analyses were performed on sources both inside and outside Norway including coal- and gas-fired power plants, cement and ammonia production facilities, gas treatment plants and ethylene and methanol processing plants.

One major uncertainty that was identified was the regularity of CO_2 supply from the sources. Their main business is the production of electrical power, cement, methanol, etc., and CO_2 is a by-product from each of these processes. Thus, production of CO_2 is dependent on the market situation for these main business areas. For example, if the gas price is high and electricity prices are low, gas-fired power plants may stop operations temporarily, thus also stopping CO_2 production. A shortage of CO_2 delivery over a long period of time is not acceptable for oil producers, given the large investments that they will have made to accommodate CO_2 injection.

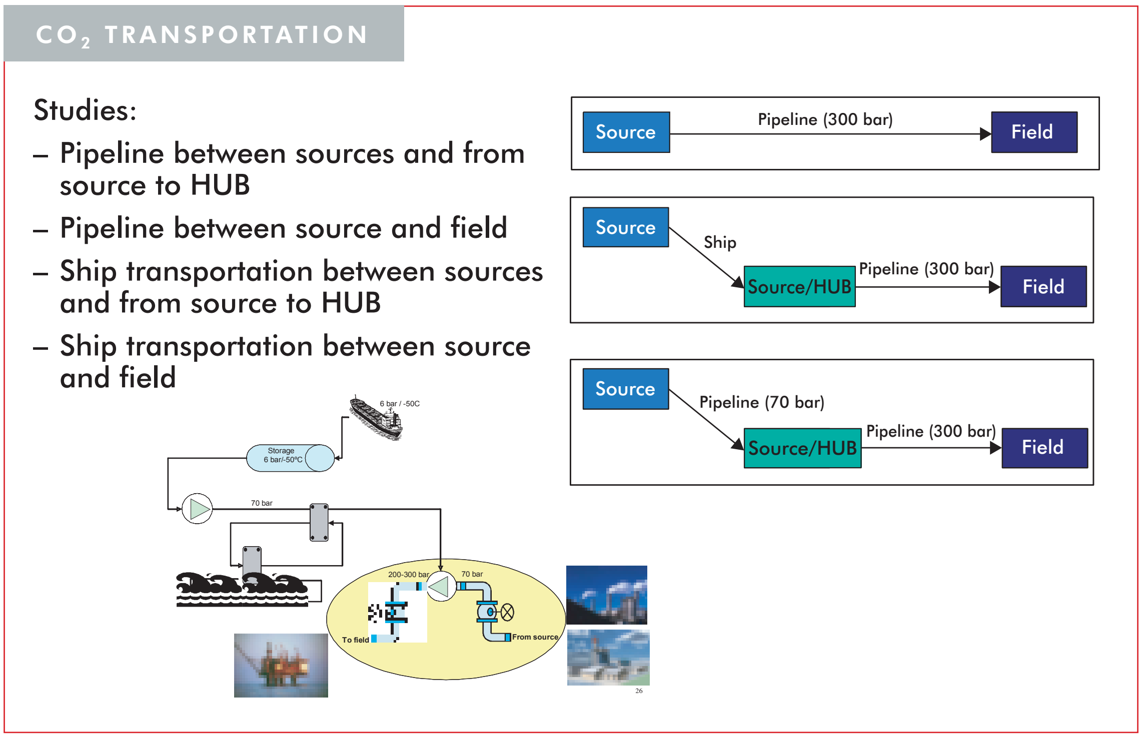

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Figure 3.

Transportation of CO_2

The security of supply issue and the large quantities of CO_2 required for EOR imply the need for supplies from more than one source, so transport logistics need to be considered carefully. In general, there are only two alternatives: transportation of liquid CO_2 under ambient temperature and at a pressure above approximately 70 bar gauge in a pipeline, or by ship at low temperature (lower than -50°C) and at a pressure of approximately 6 bar gauge. If a hub for collecting CO_2 from different sources is to be established, the choice between ship and pipeline transport is normally the result of a cost optimal analysis, and will be dependent on transportation distances and the volume of CO_2 to be transported (see *Figure 3*).

Ships can also be used for transportation to offshore fields, using loading buoys. In this case, factors such as regularity and safety issues need to be addressed closely. Poor weather conditions might mean that the ships have to be larger than necessary from a pure volume perspective – smaller, volume-optimal ships may not be able to cope with extreme weather conditions. Moreover, introducing loading buoys and offloading operations offshore normally implies that the overall safety-related risk at the oil field is increased.

For the offshore fields which were part of this study, the cost analyses showed that using loading buoys was more expensive than using a pipeline and that, in general, the weight of the necessary compression facilities could be a limitation on offshore installations where spare weight capacity is scarce. Thus a pipeline from the hub will normally be expected to be the preferred alternative.

The technical challenges involved in the transportation of CO_2 are considered to be manageable. CO_2 is highly suitable for pipeline transportation as its viscosity is low, which means that the relationship between inlet and outlet pressures is favourable. There are many pipelines that have been in operation for a long period of time, providing experience that can be utilised in new projects. CO_2 transport by ship is already established,


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albeit on a smaller scale for use in products such as mineral water. The main parameter that needs to be considered is the water content which, if left too high, might cause corrosion.

Liability

The intention is that all the CO_2 injected into the reservoir be left there on a permanent basis. Thus, analyses will have to be performed in order to establish a reservoir's suitability to contain CO_2 without any leakage over a timeframe of hundreds of years. Of course, it is not possible to obtain 100% certainty in this regard, meaning that some sort of liability has to be defined – who will be responsible if CO_2 starts leaking from the reservoir in 150 years? Requiring commercial companies to take on this long-term obligation will be a challenge, and can we even be sure that these companies will exist at that time? In any case, the issue of liability needs to be sorted out for commercial players to make investment decisions related to CO_2 for EOR.

What about the economics?

The future of carbon sequestration depends on the relationship between quota prices set for CO_2 and the cost of carbon capture and storage. From a climate perspective, the concept behind using CO_2 for EOR is that the profit from boosting oil production should (at least) fill the gap between the extra costs and the quota price.

Clearly, the economic analyses are highly sensitive to the EOR volume. What might be more of a surprise, however, is that the different projects in the study were not as sensitive to the oil price as one might have expected. Increased oil prices certainly imply additional extra income, but also a significant cost element since gas (indexed to oil) is a major cost element in the value chain. It is used to operate CO_2 capture facilities, while there is also an opportunity cost for fields with associated gas production. Introducing CO_2 into the reservoir reduces the specification of associated gas below a saleable level and thus removes an income stream (it is too expensive to bring the associated gas back up to specification). The higher the market price the higher the value of this lost income.

The study concluded that the extra oil production would not be enough to offset the significant costs related to capture, transport and offshore modifications, and that even if CO_2 quotas were defined as an income element for the total volumes injected, there would be a significant negative economic balance for all of the possible oil fields that were evaluated. However, it pointed out that this conclusion could change if further studies and analysis of reservoir simulations led to increases in the estimates of EOR volume.

In the absence of commercial incentives it will be a challenge to encourage commercial players to enter into long-term commitments. There are also significant uncertainties as regards technical challenges at the offshore oil fields and possible future CO_2 quota regimes.

Conclusions

In general, there were no technical show-stoppers identified in using CO_2 for EOR. The need for offshore modifications is significant but feasible, and transportation of CO_2 is considered to be manageable. It remains to be confirmed that existing technology for CO_2 capture can be developed on the scale necessary for the volumes that are relevant in this context, but the relevant suppliers have said that they expect this to be feasible.

What remain the chief uncertainties are the EOR potential in the oil fields and CO_2 quota prices. The oil potential can be defined better through reservoir simulations but future quota regimes will have to be defined by regulators, and will remain an uncertainty until that has been done.

Sigve Apeland of Gassco's Financial and Commercial Development Department was the Project Manager of the CO_2 Value Chain Study carried out for the Norwegian Ministry of Petroleum and Energy in 2006. He is also the leader of IGU's Study Group 3.3.

National Hydrocarbons Corporation

Inviting you to invest in oil & gas exploration/production in Cameroon

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Website: www.snh.cm

Board Chairman: Jean-Marie ATANGANA MEBARA
Executive General Manager: Adolphe MOUDIKI
Exploration Manager: Jean-Jacques KOUM
Production Manager: Bernard BAYIHA

Industry background

- Cameroon's average oil production from 1 January to 31 March 2006: 89 943 barrels/day.
- Operators in production: Total E&P Cameroun, Pecten (an affiliate of Shell US), Perenco and ExxonMobil.
- Operators in exploration: ExxonMobil, Total E&P Cameroun, Sterling Cameroon Ltd, Turnberry, Euroil, Perenco Oil & Gas, ConocoPhillips, Pecten, Addax, Perenco Cameroon, Kosmos Energy Llc, RSM Production and Tullow Oil Plc.

The National Hydrocarbons Corporation (SNH), which works in association with the above-mentioned operators, markets the share of national crude oil production which accrues to the State.

The 1999 Petroleum Code and its implementation instruments together with the 2002 Gas Code, offer incentives to potential investors in the oil and gas sectors.

Cameroon: Development of Gas Resources

A stimulating legal and regulatory framework

Two attractive texts set applicable rules in the gas sector: law n° 2002/0313 of 30 December 2002 to institute a gas code, and decree n° 2003/2034/PM of 4 September 2003 defining modalities for the implementation of this law.

This code provides for:

- The concession regime for transport and distribution activities;
- The licence regime for processing, storage, importation and exportation activities;
- The authorisation regime for the sale of gas, importation and installation of equipment and materials intended for the commissioning of gas transport and distribution networks (gas storage centres, measuring and safety equipment to be used by operators and customers).

Moreover, it specifies the applicable accounting, financial, fiscal and customs provisions.

Substantial proven and potential reserves

With 157 billion m^3 of proven natural gas reserves for an estimated unexploited potential of 570 billion m^3, SNH is implementing several projects.

To foster the realisation of all the said projects, the Cameroon Gas Association was created on 26 October 2005, on the initiative of SNH.

Some interesting outlets

- Power generation
- A 150 MW capacity gas fired thermal plant at Kribi by 2008

A production sharing contract was signed on 7 March 2006 for the development and exploitation by operator Perenco, of the Sanaga Sud gas field, in the Douala/Kribi-Campo basin, with a view to supplying a gas-fired Thermal Plant due to be constructed near the town of Kribi.

Estimated reserves of the Sanaga Sud field: 1 062 BCF in the median case

Amount of initial investment upstream, gas fired turbines and 100km transmission line: about US$200 million.

- Collection of associated gas, currently flared on platforms, to substitute heavy fuel oil at the Limbe thermal plant
- Exportation of natural gas

The first such project, which concerns exportation to Equatorial Guinea, is expected to be completed by 2009-2010.

- Supply of gas as energy source to industries
- Production and distribution of liquid petroleum gas (LPG)
- Methanol production

A rig in the Douala/Kribi-Campo basin: 18 wells were drilled in Cameroon between 2004 and 2005.

The Brass LNG Project

Brass LNG is a company incorporated under the laws of the Federal Republic of Nigeria. The Shareholders are Nigerian National Petroleum Corporation (NNPC) (49%), Eni International (17%), Phillips (Brass) Limited (an affiliate of ConocoPhillips) (17%) and Brass Holdings Company Limited (an affiliate of Total) (17%). The Company was formed to construct and operate a Liquified Natural Gas Plant to be sited on the Island of Brass, Bayelsa State, in Nigeria's Central Niger Delta following a Heads of Agreement signed in 2003 by the Shareholders.

The contract for the Front End Engineering Design (FEED) of the proposed LNG Plant was awarded to San Francisco-based Bechtel Corporation in late 2004. This followed the completion of conceptual studies that assessed the viability of building an onshore LNG facility in the region of Brass Oil Terminal operated by Nigerian Agip Oil Company (NAOC). The FEED was for two LNG trains, each nominally sized at 5 million metric tons per year.

The primary FEED studies were conducted in 2005 with further optimisation in 2006. This paved the way for the competitive Engineering Procurement and Construction (EPC) tendering process, which is in progress. The facility is targeted to be in operation by 2011.

Natural gas supplies for the facility will come from the substantial gas reserves within oil and gas fields already operated by existing joint ventures. This will be a world-class LNG facility and an important and strategic opportunity for the joint ventures to reduce gas flaring in Nigeria. Furthermore, it will be an additional opportunity for Nigeria to monetise part of its vast natural gas reserves. The project enables the respective companies to be important players in helping to meet the growing worldwide demand for clean energy, and strengthens their long-term relationship with NNPC and the Federal Republic of Nigeria.

Funsho Kupolokun, Group Managing Director, NNPC exchanging the signed Shareholders' Agreement for the LNG Plant with Todd Creeger, MD Phillips (Brass) Limited. Looking on is Dalhatu Makama, Brass LNG's Company Secretary and Legal Adviser.

The first major milestone was the Environmental Impact Assessment (EIA) in May 2006 and thereafter signing of the Shareholders' Agreement in September 2006. The Shareholders' Agreement regulates the manner in which the Company will undertake the project.

The company's marketing strategy aims at developing long-term LNG Sales and Purchase Agreements which provide for maximum returns to the shareholders. The primary market for the LNG will be the Atlantic Basin (North American and Europe), where the company seeks to become one of the key players.

Brass LNG limited is positioned to utilise best industry practices to conduct its business. Special attention will be given to safety of personnel, the public and facilities; protection of the environment; and partnership with all stakeholders, especially neighbouring communities. This will enhance sustainable development which is a key goal of the community. The company seeks to be the leading producer and marketer of LNG.

Kupolokun with Giancarlo Vacchelli, Regional V-P West Africa & Libya for Eni Int'l N.A.N.V. Sarl.

Kupolokun with Jean Luc Porcheron, V-P Brass Holding Company Limited for Total.