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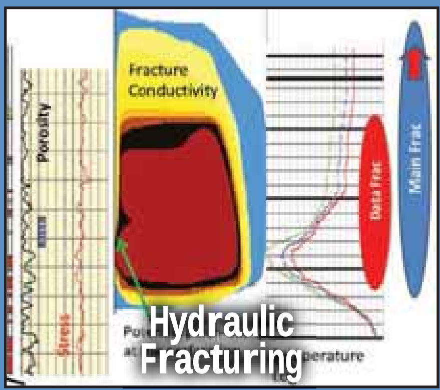

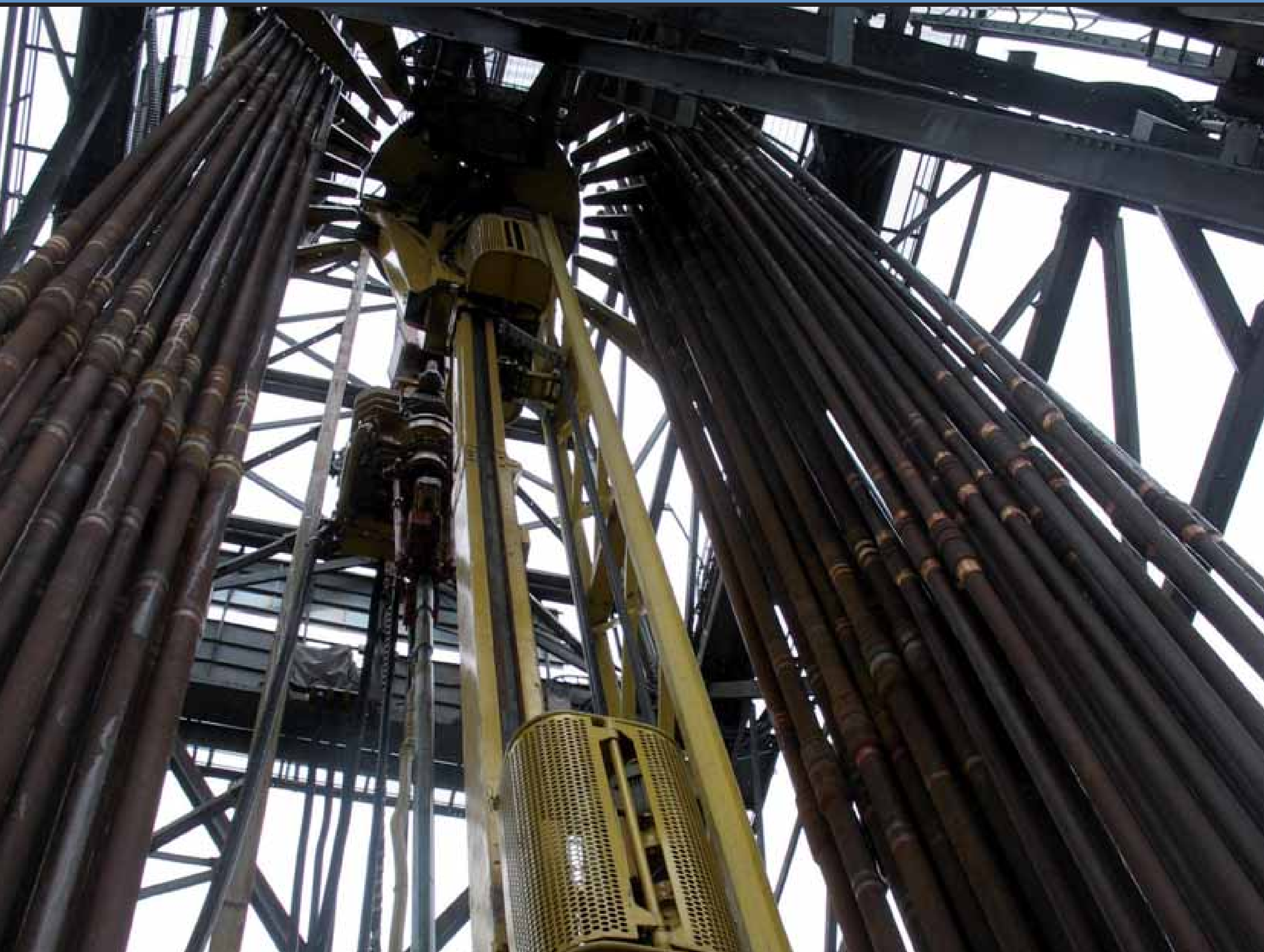

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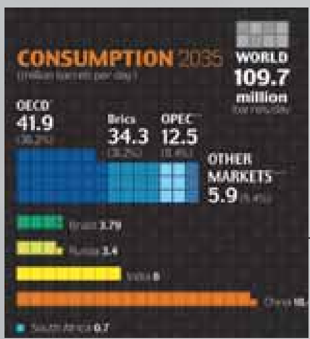

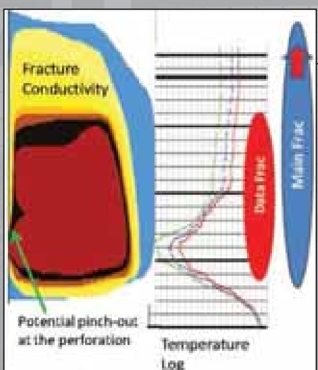

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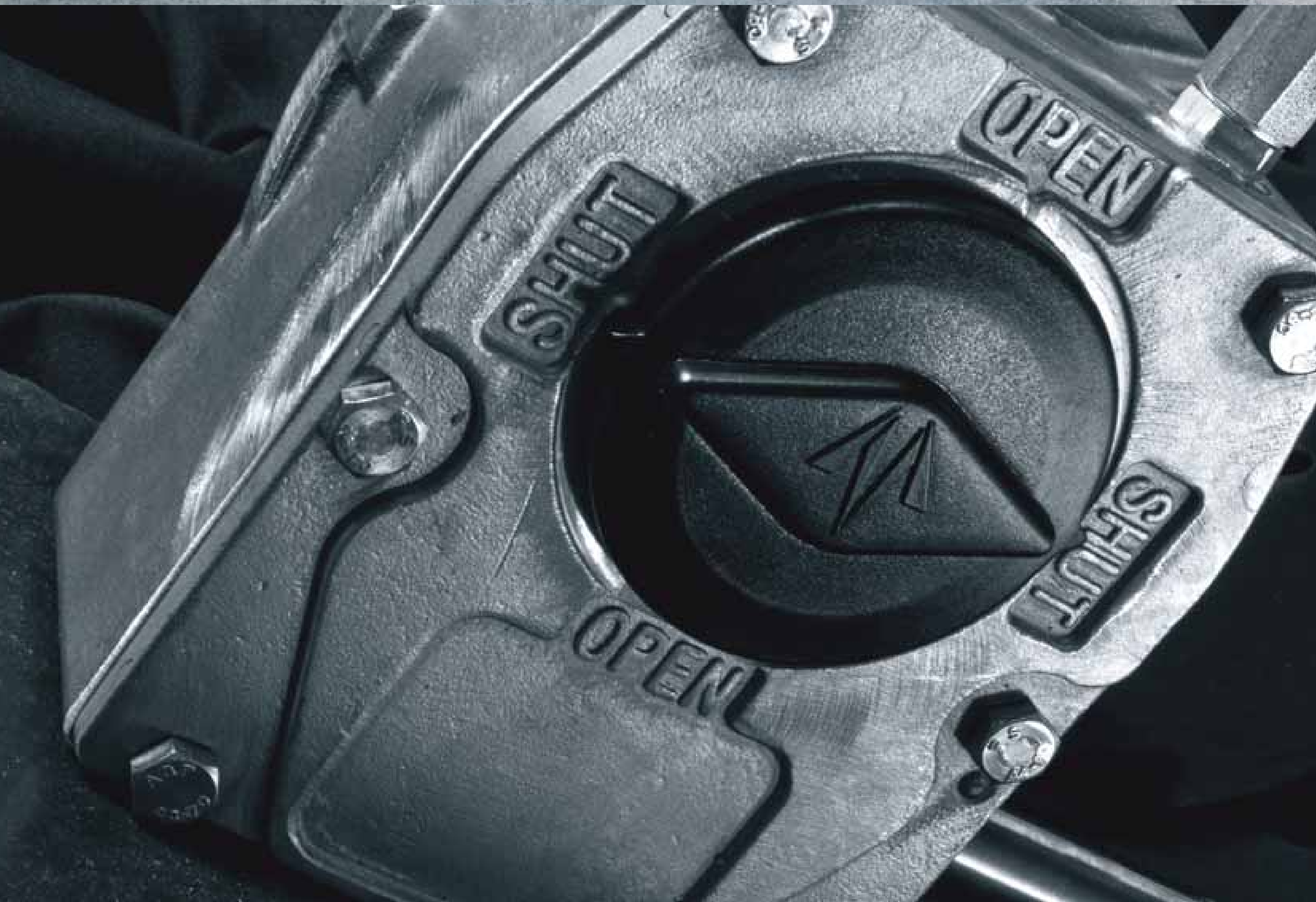

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Lula-Mexilhão Pipeline Begins Operating in the Santos Basin

Considered a milestone in Brazilian engineering, the Lula-Mexilhão pipeline, which connects the field of Lula to the Mexilhão platform, located in shallow waters in the Santos Basin, began to be operated in September 2011, by the consortium of the BM-S-11 block, formed by Petrobras (65% – Operator), in partnership with BG Group (25%) and Petrogal SA Brazil - Galp Energia (10%). With a capacity to transport up to 10 million cubic meters per day, the installation will carry gas produced in the Pre-Salt Pole of that basin. The project is strategic not only in developing the production of the pre-salt Santos Basin, but also in increasing flexibility in gas supply to the Brazilian market.

In depth and length, it is the largest submarine pipeline ever installed in Brazil – 216 km long, 18 inches in diameter and with an operating pressure of 250 bar (unit of pressure). It starts from a water depth of 2,145 meters (where it is connected to the platform vessel Cidade de Angra dos Reis, in the field of Lula), and goes up until it reaches 172 meters in depth, connecting to the Mexilhão platform – the largest fixed production unit installed in the country, owned by Petrobras.

Lula-Mexilhão is connected to the pipeline that links the field of Mexilhão to the Monteiro Lobato Gas Treatment unit in Caraguatatuba (state of São Paulo), enabling the gas flow to the coast, and to the pipeline Caraguatatuba-Taubaté, which connects the gas produced at that unit to the distribution network of natural gas to the Brazilian market. The plants belong to Petrobras.

The project is strategic not only in developing the production of the pre-salt Santos Basin, but also in increasing flexibility in gas supply to the Brazilian market.

Consortium Makes New Oil Discovery in the Gulf of Mexico

A new oil discovery in the Southwestern corner of the Walker Ridge concession area – on deepwater, at the North America's Gulf of Mexico – was reported in November 2011 by the consortium formed by Petrobras America (35% participation), Statoil (the consortium's operator, with a 35% stake), Ecopetrol America and OOGC (equity of 20% and 10% respectively).

The discovery of Logan is located approximately 400 kilometers southwest of New Orleans, at a water depth of around 2,364 meters, and was made by drilling of the well WR 969 #1 (Logan # 1), at the WR 969 block. Further exploratory activities will define Logan's recoverable volumes and its commercial potential.

In the US portion of the Gulf of Mexico, Petrobras is the operator of the fields of Cascade (100%) and Chinook (66.7%) and holds a stake in the discoveries of Saint Malo (25%), Stones (25%), Tiber (20%), Hadrian South (23.3%), Hadrian North (25%) and Lucius (9.6%), all with significant oil reserves. Petrobras also holds other exploration concessions in the region, which will be tested later on.

In the US portion of the Gulf of Mexico, Petrobras is the operator of the fields of Cascade and Chinook and holds a stake in the discoveries of Saint Malo, Stones, Tiber, Hadrian South, Hadrian North and Lucius.

Petrobras' First Windfarm goes into Commercial Operation

With an investment of US$ 424 million, the Mangue Seco Wind Farm, Petrobras' first wind farm, went into commercial operation in November 2011. Located in the state of Rio Grande do Norte, Northeastern Brazil, it is formed by plants Potiguar Cabugi, Juriti and Mangue Seco.

The Potiguar plant went into commercial operation on August 26, and the Cabugi and Mangue Seco, on September 24 and October 6, 2011, respectively. The whole wind farm has been in commercial operation since the beginning of activities of the last plant, Juriti, on November 1.

Located next to the Clara Camarão refinery in Guamaré, the plants are equipped with 52 wind turbines, each one with a 2 megawatts (MW) capacity. That means that the Mangue Seco Wind Farm has the largest installed capacity (104 MW) among the farms equipped with this type of turbine in Brazil. That's enough to supply electricity to a population of 350,000 inhabitants. The energy generated by the units will be available for the National Interconnected System. The Cabugi plant was built in partnership with Eletrobrás, the Mangue Seco plant was built in partnership with Alubar Energia, and the Potiguar and Juriti plants were built in partnership with Wobben WindPower.

Located next to the Clara Camarão refinery in Guamaré, the plants are equipped with 52 wind turbines, each one with a 2 megawatts (MW) capacity.

The Changing Face of World Oil Commerce

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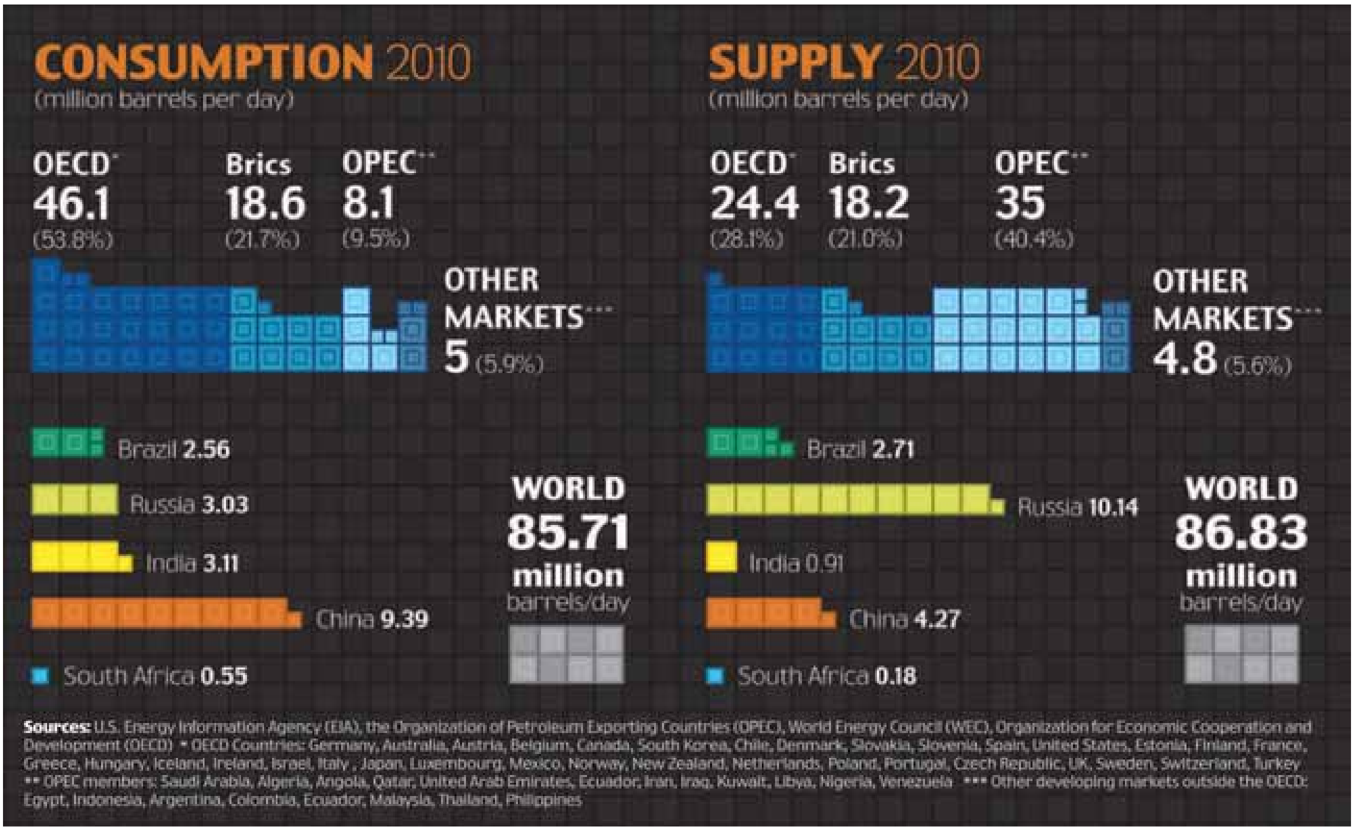
The increase in energy comsumption in emerging economies and the reduced demand from developed countries, coupled with the rise of new producing regions, alter the flowof world oil commerce.

Leveraging the world economy is a task that demands a lot of fuel. And those who step on the gas need to refill their tanks more often. While the old "engines" – USA, Japan, Europe – are slowing down, newer driving forces – the Brics and other developing countries – gain momentum and change energy's global geopolitics. The direction of the oil trade is changing, both for those who buy and consume and for those who produce and offer the fuel. In this new context, Brazil - a country in economic expansion - prepares to consolidate itself as a major exporter of oil and its by-products.

The developed countries – that historically have been the biggest consumers of oil in the world – have not been registering significant growth in their demand of fuel. A recent survey by the U.S. Energy Information Administration (EIA) shows that, between 2010 and 2011, oil demand among the members of the Organization for Economic Cooperation and Development (OECD) fell 0.91% (from 46.1 million barrels day to 45.68 million). The forecast for 2012 is for another fall to 45.65 million barrels. Until 2035, this demand will be reduced by 4.6% in the European

Besides the diminishing demand in developed countries and the increasing consumption in developing countries, the drop in the oil production in some regions, along with the increased supply from others, are also changing the global flows of the oil trade



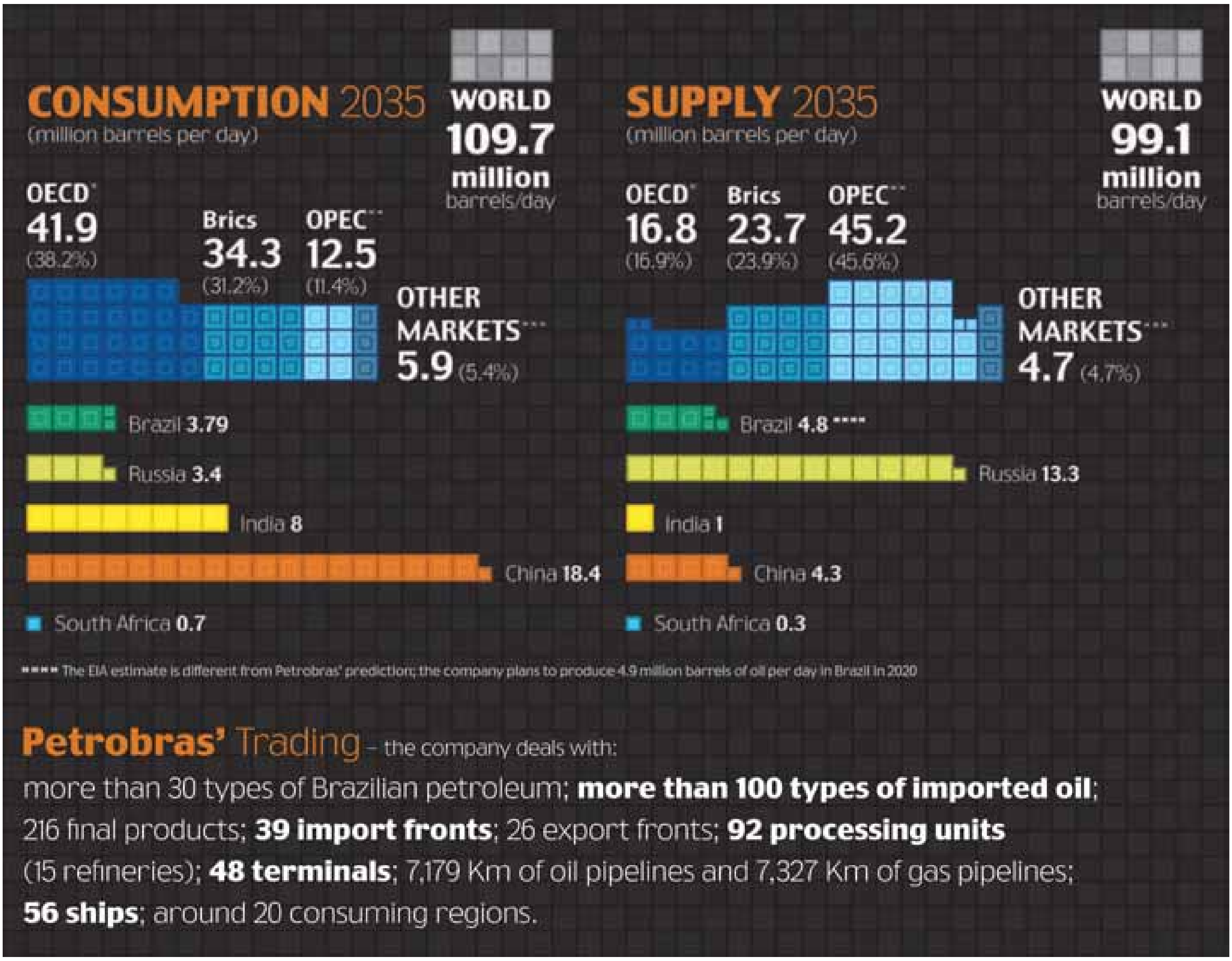
Union, and will rise only 4.9% in developed countries.

Moreover, since the 1990s, consumption in developing countries has tripled in comparison with developed nations, due to the expansion of economic activities, which increased energy consumption. According to EIA, consumption in emerging markets rose 2.76% in the last two years and is expected to attain a new high for 2012 (from 42.45 million barrels per day to 43.87 million). Another study released by the OECD estimates that developing countries will account for 68% of the total increase in oil demand by 2020. Until 2035, EIA's projections indicate that the fuel demand in these countries will grow by 63.9%.

In short, the growing economies – particularly in the Bric countries – will dictate the increase in worldwide oil consumption. Matthew Parry, an analyst of demand in the oil industry at the Marketing Division of the International Energy Agency (IEA) says that the change gained momentum from 2004, when the Gross Domestic Product (GDP) in emerging markets reached a high level after consecutive increases in annual growth rates. "While the growth of developing countries became more permanent, the rates at the developed economies began to stagnate and even to retreat," he says.

Besides the diminishing demand in developed countries and the increasing consumption in developing countries, the drop in the oil production in some regions, along with the increased supply from others, are also changing the global flows of the oil trade. Projections by the Organization of Petroleum Exporting Countries (OPEC) and by the U.S. Department of Energy indicate that the decline in conventional oil supply in Europe, in Asian countries bordering the Pacific Ocean and in North America will be partially offset by growth in exploration and production in deep waters in Russia and Brazil. In the European country, the production of large reserves of the Caspian Sea should begin in 2014. Brazil, on the other hand, will consume more oil, produce an even greater volume and be strenghthened as an important supplier of oil and oil products, mainly due to oil extracted from the pre-salt layer.

Alfredo Laufer, a consultant at the Brazilian Institute of Oil, Gas and Biofuels (IBP), analyzes the evolution of Brazil's role within the global energy context: "Until 1950, Brazil imported a lot of oil. As of the Six-Day War (1967), with the intensification of conflicts in the Middle East, there was an increase in oil prices and the Brazilian government started to seek reserves at the sea. The technologies have developed and in 2006 the Pre-



Salt Pole was discovered," he explains. In the light of the new discoveries, Petrobras expects that the volume of oil and natural gas found in the pole will double the Brazilian reserves, now estimated 16.4 billion barrels of oil equivalent (boe), according to criteria of the Society of Petroleum Engineers (SPE).

Due to increased production, it is expected that the growth in Latin America will be driven by the Brazilian reserves. The latest World Oil Outlook report, released by OPEC in 2011, envisions a 51% increase in production in the region (4.7 million bpd to 7.1 million) by 2035. The same period will be marked by a sharp decline in supply from Asia, Africa and non- OPEC Middle East countries. The document also points out: "Mainly because of Brazil, Latin American countries will be the biggest suppliers of oil among all developing countries, excluding the OPEC members."

From Price Taker to Price Maker

Today, Petrobras trading teams activities include the importing of oil and oil products (such as diesel, LPG and naphtha) for the Brazilian market and the exporting of Brazilian oil and derivatives to other countries. While the full potential of the Pre-Salt Pole is not being explored, the company continues to carry out systemic trading – buying the needed products and selling the surplus – and the complementary trading – which takes advantage of good opportunities to buy and sell products abroad, adding value to operations. Besides that, Petrobras does the supplying, storing and mixing of products and operates in the wholesale and reselling markets. According to the executive manager of Marketing and Sales Officer, José Raimundo Pereira Brandão, the goal is to overcome the dependence of the external market and elevate the company from the

If in 2010 Petrobras exported a daily average of 698,000 barrels of oil equivalent (including crude oil, derivatives and ethanol), the projection for 2020 is an increase of 231.4% in sales abroad.

position of price taker to the position of price maker.

Brazil's current oil consumption is greater than the amount of products generated by the country's refineries. With the increase in oil production estimated by Petrobras, the forecast is that by 2020 the situation will be reversed, with the demand being lower than the processed volume. This will enable Petrobras to export high-value products, instead of crude oil essentially.

"Initially, Petrobras' trading consisted basically in importing oil derivatives to supply the Brazilian market," says Pereira Brandão. "With the building of refineries between 1950 and 1970, the company began to buy oil from abroad to be refined in Brazil. Later, the light oil acquired abroad was mixed with the heavy oil produced in Brazil, since our refineries were designed to only handle light oils. Since then, lighter oil have been found in Brazil and the Brazilian refineries were adapted to process heavy crude as well," he says.

"Now, mainly due to the pre-salt, Petrobras will more than double its daily production capacity of oil by 2020, when it will be producing nearly 5 million barrels of oil per day (bpd) in Brazil. In this context, the company will reduce imports and increase the participation of the Brazilian oil on its trading operations," says Pereira. "To handle the increase of the produced volume, the Company has begun operating the Clara Camarão Refinery in 2009 and it will invest in four more medium or large units. Together, these refineries will add 1.3 million bpd to the volume refined in Brazil until 2020. There will be a reduction in the import of derivatives and, consequently, also in the freight costs," he adds.

If in 2010 Petrobras exported a daily average of 698,000 barrels of oil equivalent (including crude oil, derivatives and ethanol), the projection for 2020 is an increase of 231.4% in sales abroad. That means 1.65 million barrels of crude oil per day, 636,000 barrels of derivatives and 26,000 barrels of ethanol. Currently, Petrobras' main export destinations are the USA and China. Shipments to India have also grown significantly in recent years. In 2020, after having supplied the needs of Brazil's expanding domestic market, Petrobras plans to export its surplus of derivatives mainly to the USA, Northwest Europe and other countries in the Mediterranean region of that continent. The company also intends to provide ethanol to the U.S., Japan and Europe. These movements strengthen the position of Petrobras in the unfolding scenario, reflecting Brazil's growing importance as an exporter and consumer in this new world order.

Petrobras Invests in Renewable Energy to Grow its Share of the Brazilian Ethanol Market

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Commanding a mechanic harvester through a sugarcane field, Edson Aparecido Ferreira has only one companion: the country music coming from his radio. At the Cruz Alta sugarcane processing plant, located in Olimpia, in the state of São Paulo, the sugarcane harvest ended in November 2011. The work, however, never ceases. In the field, projections about the next harvest are already being made and a battalion of machines and workers is preparing the 295,000 hectares of sugarcane fields surrounding the plant – the equivalent of twice the size of Mexico City. The cycle then begins anew. Ferreira has been working in Cruz Alta (one of the nine ethanol plants in Brazil in which Petrobras has a stake) for four years. And he helps to move, along with other important players, a productive chain that is profitable, cleaner, sustainable, and, above all, prosperous.

The Brazilian ethanol market is agitated. In the last few years, large companies from the energy and the food industries started to invest in the sector. Petrobras took a decisive step in this direction four years ago with the creation of the subsidiary Petrobras Biocombustível (Petrobras Biofuel). The company's Business Plan 2011–2015 predicts an investment of US$ 1.9 billion in expanding production of ethanol, with the construction of new mills and distilleries, the increase in milling capacity and renewal of plantations. Another US$ 1.3 billion will be invested in logistics and further US$ 300 million will be used in research and development of new technologies. The aim is to expand Petrobras' production capacity (alongside with its partners) from the current 1 billion to 5.6 billion liters, reaching a 12% share in the domestic market in 2015 and, consequently, taking the leadership of the Brazilian market.

Petrobras has acted in the ethanol segment since the 1970's, at first participating in the Pró-Álcool (Pro-Alchool, Brazil's federal government program to stimulate the use of ethanol as a fuel). The company began to invest more heavily in biofuel production in 2009 by acquiring 43.58% of Total Agroindústria Canavieira, a company which owns a sugarcane plant in Bambuí (state of Minas Gerais). The following year, Petrobras closed a new partnership, this time with the French group Tereos, acquiring 45.7% of Guarani company. With seven manufacturing plants in Brazil, all located in the state of São Paulo, and one in Mozambique, Africa, Guarani is the third largest processor of sugarcane in Brazil. Finally, also in 2010, Petrobras signed an agreement with the São Martinho group, forming the Nova Fronteira Bioenergia company, which controls the Boa Vista plant in Quirinópolis (state of Goiás). Along with these partners, two initiatives stand out: the expansion of the Boa Vista plant, which upon receiving investments of US$ 293.7 million until 2015, will increase its production capacity from 200 million to 700 million liters of ethanol; and the expansion of ethanol production and energy cogeneration in the Guarani production units, with investments over US$ 423.7 million made in the next three years.

"(Going to) the market for renewable energy is a natural path. Choosing ethanol seemed to be the most logical option, since it allowed us to work with liquid fuels,

‘The investments made in the three partners of Petrobras Biocombustível will enable us to achieve, by 2015, a 12% share of the Brazilian ethanol market.’

a field in which we have great expertise. Three pillars guided our investments: energy security, environmental issues – the reduction of greenhouse gas emissions – and social issues, generating new jobs and more income,” explains Ricardo Castello Branco, Petrobras Biocombustível’s ethanol director. “Boa Vista’s expansion will make it the largest sugarcane ethanol plant in the world. Besides that, we will double the annual production of Total’s unit in Minas Gerais. The investments made in the three partners of Petrobras Biocombustível will enable us to achieve, by 2015, a 12% share of the Brazilian ethanol market,” he adds.

Brazil is the world’s largest producer of sugarcane ethanol. According to Unica (Brazil’s national union of sugarcane producers), 20.5 billion liters of fuel were produced in the country in the 2011–2012 harvest. Almost the entire production was directed to the domestic market. Meeting the needs of the Brazilians is the natural way for local businesses, but the export potential of sugarcane ethanol is indisputable. “Brazil’s market has become very attractive for investments because of the pent-up demand and the growing fleet of flex-fuel vehicles. Ethanol is efficient and less polluting. It’s only a matter of time for it to become a widespread global commodity,” says Andy Duff, global specialist on sugar at Rabobank’s department of Research and Sector Analysis. Headquartered in the Netherlands, Rabobank is the world’s leading institution on financing and investment on segments related to sustainability and agribusiness.

An interesting perspective for Brazilian ethanol was opened in late 2011 when the U.S. Congress repealed the tax imposed on the biofuel from Brazil and suspended the subsidy to local producers. The United States are the world’s largest producer of corn ethanol. The decision can still be changed, but it signals a positive prognosis for Brazilian exports. “When sugarcane ethanol was recognized as an advanced biofuel, it won a passport to travel the world,” said Marcos Jank, president of Unica, referring to the announcement by the U.S. Environmental Protection Agency in February 2010. According to the agency, the sugarcane fuel reduces by more than 60% the emissions of greenhouse gases in its total life cycle when compared to gasoline. That is enough for it to be considered an “advanced biofuel. It is time for Brazil and the United States, which together account for more than 80% of ethanol produced worldwide, to show their leadership and work to create a true global market, comparable to the oil market,” adds the executive.

Past, Present and Future

The sugarcane industry’s roots go back to the beginning of colonization in Brazil. The favorable climate and the vast availability of land contributed to make sugarcane culture the foundation of the country’s economy during the so-called sugarcane cycle, beginning in the 16th century. Ethanol from sugarcane began to gain importance as a fuel in the late 1920s, when it was mixed with gasoline. It began to be regarded as an alternative to petroleum derivatives during the 1973

world supply crisis. The launch of Pró-Álcool (National Alcohol Programme) in the late 1970s marked the beginning of an energy program based on ethanol. By 1989, government incentives had helped to build a fleet of about 4 million vehicles that ran on ethanol (a third of the total Brazilian fleet at the time). On the path to become a global commodity, the development of the so-called cellulosic (or second-generation) ethanol will be crucial. The main benefit will be to increase the amount of ethanol produced without expanding the raw material planting fields. The strategy to get there includes the use of waste, such as sugarcane bagasse.

While in the United States the research is focused on corn waste, Brazil bets on second-generation ethanol are concentrated in bagasse and straw, cellulose sources that account for two-thirds of the plant's energy potential. "Petrobras started its studies in 2004. The main advantage of the bagasse is logistics. As it is a byproduct of sugarcane that is already available at the plant, there is no need for deployment of infrastructure for collection and transportation," explains Juliana Vaz Bevilaqua, coordinator of the Technology Management at Petrobras Biocombustível. "Today, a very good plantation produces 8,000 liters of ethanol per hectare. With second-generation ethanol, the goal is to increase production by 40% without additional planting," adds Castello. Today, the bagasse and straw are used to generate steam and electricity in power plants, making the units self-sufficient in energy. Some plants also export excess energy to the national grid.

... Petrobras and KLE will develop a project for an industrial scale second-generation ethanol plant that will be fully integrated into a sugarcane plant belonging to Petrobras in Brazil.

To accelerate the research for the production of second-generation ethanol, Petrobras firmed a partnership with U.S. company KL Energy Corporation (KLE), which was already testing cellulosic ethanol made out of wood. Petrobras invested US$ 11 million in 2011 in order to adapt to the KLE plant in Upton (USA) to use bagasse as a raw material and to validate, through testing, the production of cellulosic ethanol. Moreover, Petrobras and KLE will develop a project for an industrial scale second-generation ethanol plant that will be fully integrated into a sugarcane plant belonging to Petrobras in Brazil. The plant should be ready to operate in 2015.

Technological progress will allow the use of sugarcane as a raw material for new products in various areas of industry. André Bello de Oliveira, manager of Technical Support in Ethanol at Petrobras Biocombustível, faces the prospect with optimism and predicts that sugarcane will follow a path similar to that of oil. "In the past, petroleum was processed to replace whale oil in the production of kerosene. Whatever was left would become waste. Now, more complex refining allows us to take advantage of it all. What were the sugarcane mills in the past? Factories with human labor and animal traction making sugar. With the Pró-Álcool program, we began to produce ethanol. Today, it is possible to obtain various types of sugars and alcohols, as well as fertilizers, different types of proteins and even lysine and acids in general from sugarcane," he says. For the future, the prospects are even wider, with the emergence of biorefineries – units capable of producing fuels, polymers and chemicals from biomass, through procedures similar to those used in oil refineries – allowing a greater utilization of sugarcane and its waste, in a diverse and integral way.

The future of ethanol

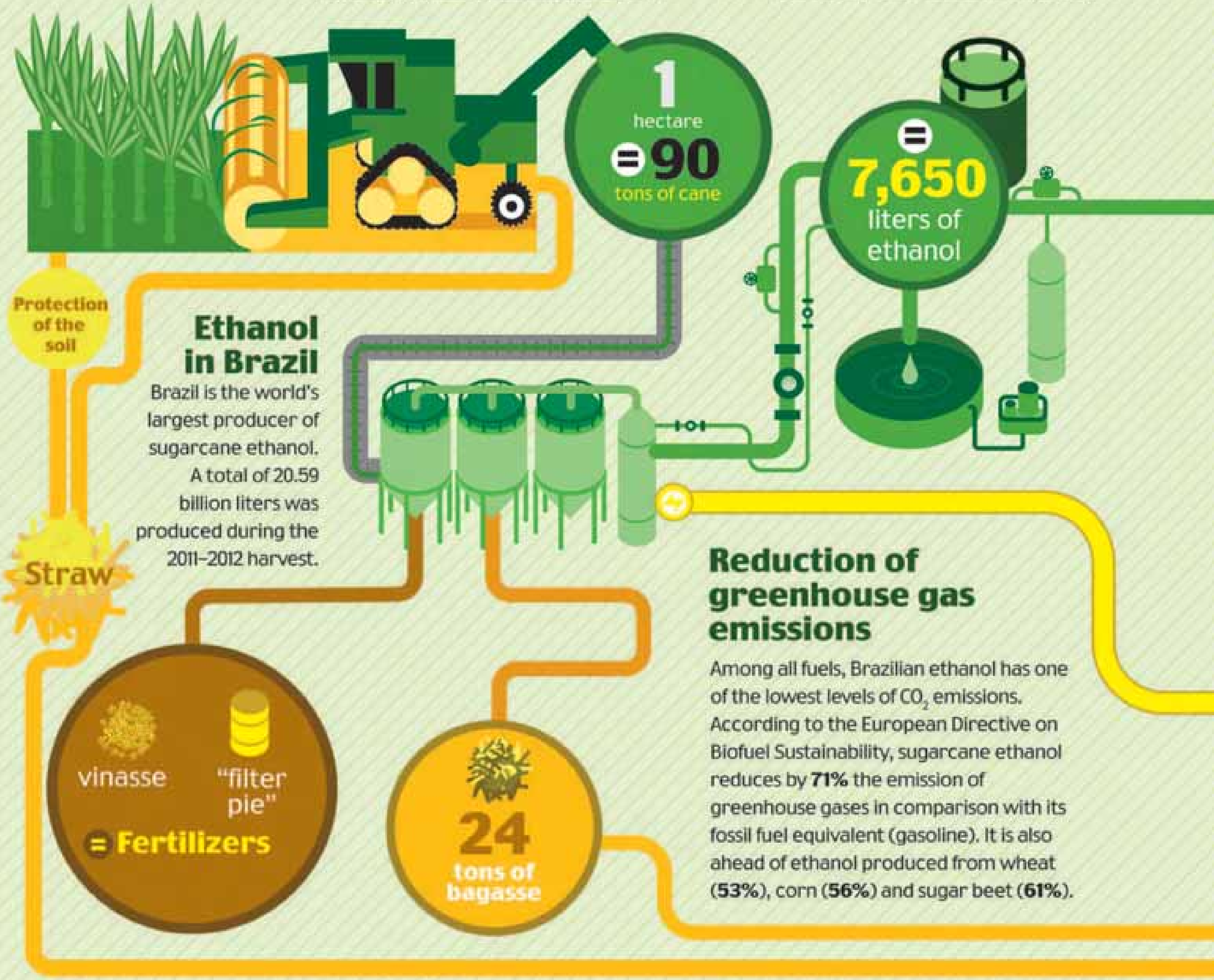
Sugarcane production in Brazil is a secular tradition. The expertise in planting and irrigation techniques that was developed over the centuries led to the research on the use of sugarcane as a base material for the production of ethanol. Petrobras will make a big investment aiming to boost its presence in the sector in the next years. Future prospects include the beginning of the production of second-generation ethanol, which will harness the energy potential of sugarcane bagasse to enable a significant increase in the volume of biofuel production without any need to expand the planting area.

Investments

The Petrobras 2011–2015 Business Plan predicts an investment of US$ 1.9 billion in order to increase production of ethanol. There will be an investment of US$ 1.3 billion in logistics and US$ 300 million will be spent in research and development of new technologies. The goal is to enhance Petrobras' (along with its partners) annual production capacity to 5.6 billion liters of ethanol, enough to grant the leadership of the Brazilian market.

Sugarcane in Brazil

Until January 2012, the milling of sugarcane in the country reached 492.7 million tons in the 2011–2012 harvest, according to Unica.



Ethanol in Brazil

Brazil is the world's largest producer of sugarcane ethanol. A total of 20.59 billion liters was produced during the 2011–2012 harvest.

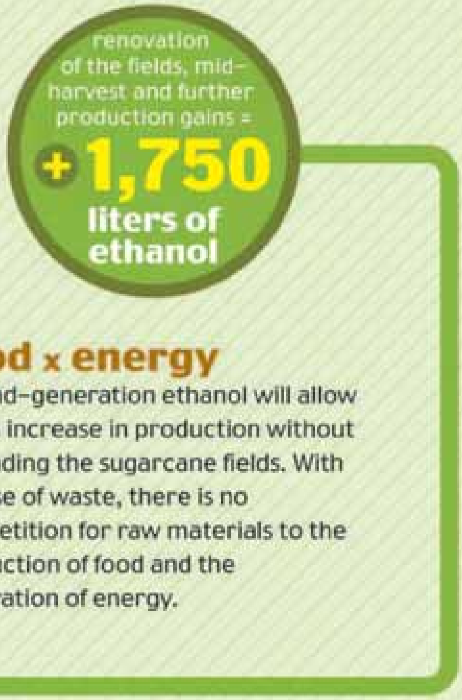
Reduction of greenhouse gas emissions

Among all fuels, Brazilian ethanol has one of the lowest levels of CO_2 emissions. According to the European Directive on Biofuel Sustainability, sugarcane ethanol reduces by **71%** the emission of greenhouse gases in comparison with its fossil fuel equivalent (gasoline). It is also ahead of ethanol produced from wheat (**53%**), corn (**56%**) and sugar beet (**61%**).

Available sugarcane bagasse in Brazil (2011–2012 harvest): 169 million of tons (Unica)

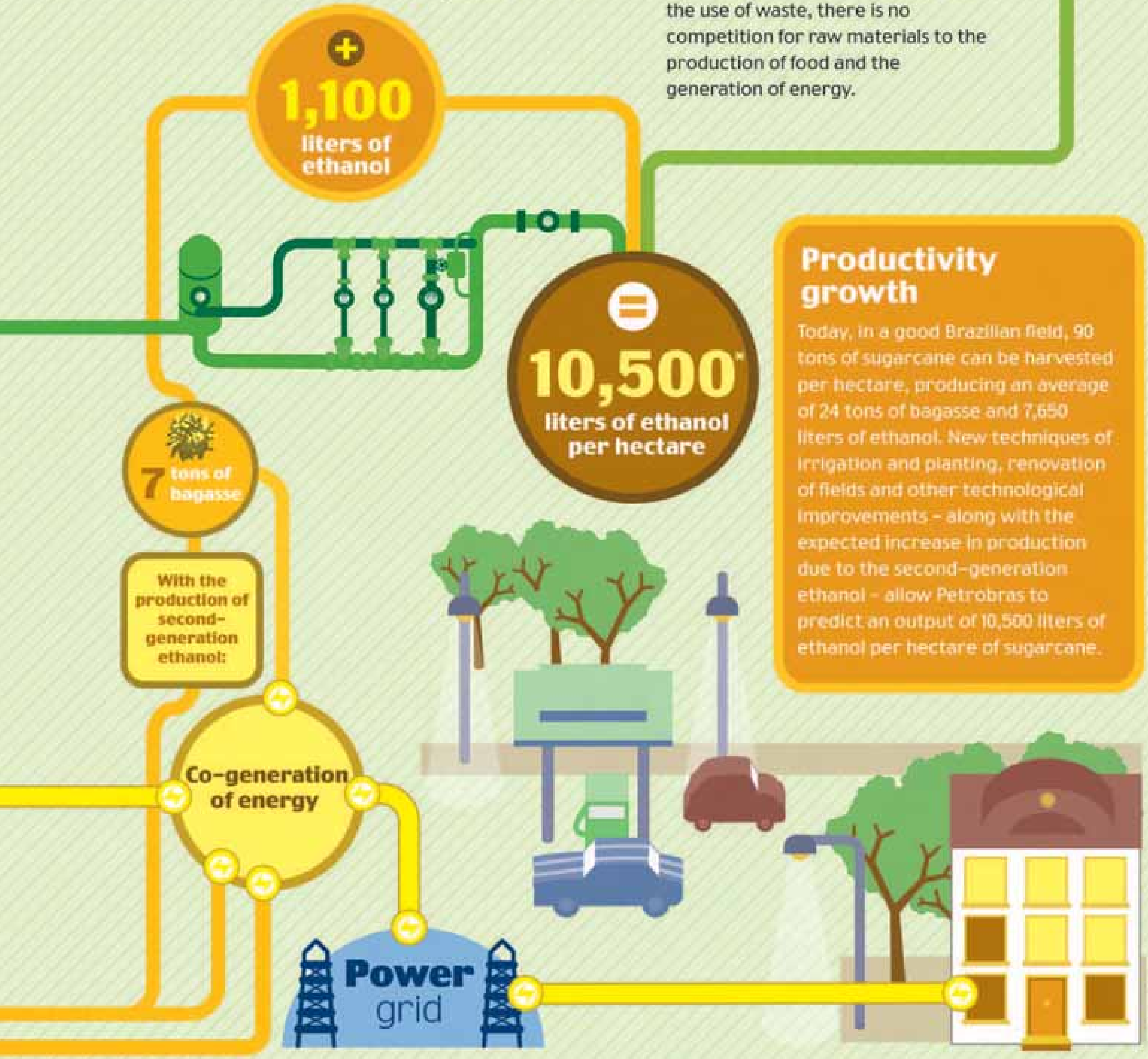
Second-generation ethanol

Second-generation ethanol will be produced from waste (such as bagasse and cane straw, in the case of Brazil). Experts believe that the process will shorten the path to the recognition of ethanol as a global commodity. In partnership with U.S. company KL Energy Corporation (KLE), Petrobras is developing the project of an industrial scale second-generation ethanol plant that will be integrated into one of the company's sugarcane mills in Brazil. This plant is expected to be ready to operate in 2015.



Food x energy

Second-generation ethanol will allow a 40% increase in production without expanding the sugarcane fields. With the use of waste, there is no competition for raw materials to the production of food and the generation of energy.



Productivity growth

Today, in a good Brazilian field, 90 tons of sugarcane can be harvested per hectare, producing an average of 24 tons of bagasse and 7,650 liters of ethanol. New techniques of irrigation and planting, renovation of fields and other technological improvements – along with the expected increase in production due to the second-generation ethanol – allow Petrobras to predict an output of 10,500 liters of ethanol per hectare of sugarcane.

* All the numbers are based on average figures

Sources: Petrobras, Empresa Brasileira de Pesquisa Agropecuária (National Agency of Agriculture Research – Embrapa), União da Indústria de Cana-de-Açúcar (Union of the Sugarcane Industry – Unica), the European Directive on Biofuel Sustainability (EU Parliament, April 23rd 2009)

Productivity Increase Using Hydraulic Fracturing in Conventional and Tight Gas Reservoirs – Expectation vs. Reality

By Dr. Zillur Rahim, Dr. Hamoud A. Al-Anazi, Adnan A. Al-Kanaan, Ali H. Habbtar, Ahmed M. Al-Omair, Nejla H. Senturk and Daniel Kalinin.

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Abstract

Hydraulic fracturing technology is widely used to facilitate and enhance the gas recovery process from conventional and tight gas resources. Tight gas or unconventional reservoirs, which include very low permeability sandstones, carbonates, or shales, cannot be economically produced without hydraulic fracturing. Recently, much progress has been made in the overall hydraulic fracturing procedures and the field implementations of advanced stimulation technology have produced good results. The proper selection of well trajectory, gel concentration, polymer loading, proppant type/size and concentration, perforation method, location for packer and frac port placement in a mul- tistage fracturing (MSF) assembly, number of fracture stages to cover the net pay, etc., have all contributed to successful stimu- lation and improved gas recovery. Even though stimulating gas reservoirs has become a routine application and much experience has been gained in this area, not all treatments are straightforward without problems and challenges. Unless a stimulation treatment is carefully designed and implemented, the post-stimulation results in moderate to tight reservoirs may not be encouraging and can easily fall below expectations.

The most essential step to close the gap between expected results and actual well performance is to understand a reservoir's characteristics and its potential to produce at a sustained rate after a successful fracturing treatment. Overestimation of reservoir flow capacity and achieved fracture geometry will also over predict well performance. This article addresses the importance and impact of detailed reservoir characterization and superior stimulation processes on final well performance. Several field examples from Saudi Arabia's gas reservoirs are presented in this article, showing the value of effective well planning, reservoir characterization, application of hydraulic fracturing and proper cleanup.

This article also illustrates the impact of drilling trajectory and wellbore reservoir connectivity on the proper placement of desired hydraulic fracture treatments and sustained gas production.

Introduction

Unconventional gas resources of tight sand, carbonate, shale, and coal have tremendous potential. All reservoirs containing conventional gas have very high percentages of unconventional resources that are now being produced or need to be produced in the near future to support world energy. Figure 1 shows the distribution between conventional and unconventional resources from a few basins in the United States, indicating huge tight gas potential[1]. Figure 2 is the well-known resource triangle depicting the availability of gas resources associated with some anticipated reservoir flow capacities[2]. The unconventional gas portion is huge, with a total of 32,600 trillion cubic ft (TCF) of gas-in-place (GIP) and 7,400 TCF in tight sand only estimated across the world. Saudi Arabia is currently embarking on projects tapping into its tight sand and shale resources. Along with citing examples from conventional reservoirs, this article also focuses on tight gas reservoirs, deployment of new technology, and making realistic estimates of well deliverability to close the gap between expected production and actual well performance.

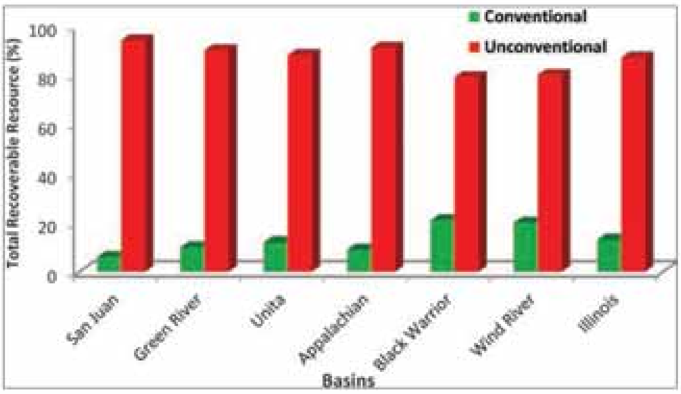

Fig. 1. Comparing conventional and unconventional gas reserves in some basins in the United States[1].

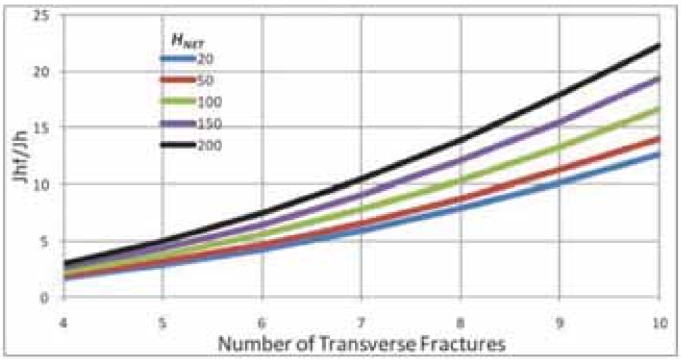

Fig. 3. Productivity increase ratio as a function of the number of fractures

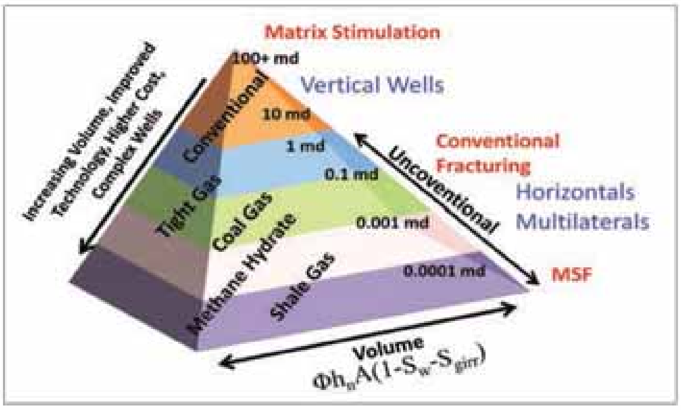

Fig. 2. Estimated reservoir properties and reserves volume[2].

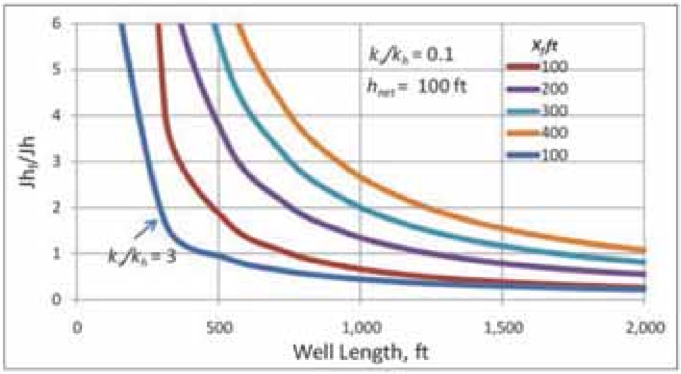

Fig. 4. Productivity increase ratio as a function of the fracture half-lengths (x_f)

Tight gas wells present challenges. They are not expected to produce at a high rate even after stimulation. They do not cleanup quickly after a stimulation treatment. The pressure transient tests conducted do not necessarily achieve a pseudo steady-state flow regime due to the slowness of fluid movement in low permeability. To improve the performance of wells drilled in tight gas reservoirs, the application of advanced drilling, completion and stimulation technology is required. Development and production of tight gas always faces many hurdles to overcome to achieve success. This article addresses improved well design and fracturing technology in moderate and tight gas reservoirs that help to realize full well and field potential.

Addressing the Challenges

In horizontal as well as in vertical wells, underachieved production performance is not uncommon. Some potential causes for underperforming wells could be:

• Not accounting for reservoir heterogeneity and permeability anisotropy.
• Inefficient perforations to connect the wellbore with the reservoir.
• Leftover damage from drill-in fluids that was neither cleaned up nor bypassed by stimulation.
• Ineffective well design.
• Ineffective stimulation treatment.
• Insufficient post-fracture cleanup causing fracture conductivity degradation.

Since its inception, hydraulic fracturing has become a strong technical process applied to oil and gas wells to overcome many of the aforementioned challenges. The primary objective of reservoir stimulation is to attain and sustain a higher gas rate in the early part of the well life to shorten the payout time. In the case of tight gas reservoirs in carbonates, sandstones and shales, wells cannot produce at any measurable rate without stimulation. Properly designed and implemented hydraulic fracturing treatments not only bypass wellbore damage, but also connect the virgin reservoir with long and highly conductive paths to ensure continuous gas flow into the wellbore. Good fracture conductivity is an essential element to minimize impact due to fluid blockage and to enhance production from high condensate gas reservoirs[3]. Major consideration must be given to selecting the correct stimulation fluid chemistry so that fracture fluid damage is minimized and post-treatment flow back is easily achievable.

A good perforation strategy also adds to the success of stimulation, particularly in deep tight gas formations with high in-situ stress, pressure and temperature. Jetting and creating slots with the use of acid or very small mesh size proppant in both vertical and horizontal completions, a viable alternative to the conventional charge perforation methods, has shown good results. The extremely high jetting velocity exerts an immense pressure on the target interval, producing good channeling/cavity communication of the wellbore with the reservoir. The perforation tunnels also make the subsequent fracturing treatment easier by lowering the near wellbore friction pressure loss[4].

The advanced multistage fracturing (MSF) applied to horizon- tal wells has proven to be a very useful technology. Depending on the well trajectory and azimuth, several fractures can be induced and propped in sequence in selected intervals to augment the flow path between the reservoir and the wellbore. For horizontal wells, the number of stages in a MSF completion depends on reservoir development, stress profile and wellbore trajectory. When a wellbore is placed along the direction of minimum in-situ stress ($\square_{min}$), the possibility that one induced fracture will over-lap another is nearly eliminated because the fracture plane goes in the direction of the maximum horizontal in-situ stress($\square_{max}$), perpendicular to $\square_{min}$ .This means multiple, independent fractures can be placed along the wellbore. On the other hand, when the well trajectory is in the $\square_{max}$ direction, the created fractures will be longitudinal along the wellbore plane, thereby limiting the number of independent fractures that can effectively be created and placed. Considering proper reservoir development and geomechanics, it is prudent to place wellbore trajectory toward $\square_{min}$ to ensure the inducing of multiple hydraulic fractures.

Figures 3 and 4 show results from analytical solutions of the productivity index (PI) ratio between fractured horizontal wells and unfractured wells as functions of a number of hydraulically created transverse fractures (NFR)[5]. The solutions also depend on the net pay thickness of the treated interval (H_{NET} or h_{net}) and the vertical to horizontal permeability ratio (k_v/k_h) as shown in the figures. For example, a horizontal well with net a pay thickness of 200 ft can double its productivity ratio with a respect to an unfractured horizontal well by increasing the number of fractures from 5 to 7, Fig. 3. Similarly, a horizontal well with 1,000 ft of reservoir contact and 300 ft of fracture half-length will have a productivity ratio that is twice that of an unfractured well, Fig. 4. The plots derived from these analytical solutions reinforce the need for conducting fracture treatments, even in cases of horizontal wells with high reservoir contact.

Improved Perforation Technology

Near wellbore tortuosity is one of many conditions that can cause additional friction pressure loss during the injection or production phase of a well[3]. Tortuosity can be caused by the creation of T-shaped fractures, reoriented fractures and multiple fractures. Good drilling and perforation practices are essential to minimize such pressure loss and establish good communication between the well and the virgin reservoir.

Regardless of the completion configuration, there always needs to be good communication between the wellbore and the formation to ensure full well potential. Such communication is achieved by the proper choice and placement of perforations. Two major types of perforation techniques that are widely used by the industry today are described in the following sections.

Conventional Charge Perforation (CCP)

In cased hole completions, shaped explosive perforation charges, or conventional charge perforation (CCP), is the most used perforation technique in the industry. CCP generates very high temperatures and pressures during the perforation process. This often creates localized stress and can crush cement bonds around perforations between the casing/formation annulus. Also, perforation creates crushed zones of very low permeability around the tunnels, which restricts both injection and production. Another perforation method characterized by extreme underbalance, in which a severe pressure drop is created simultaneously with the discharge of explosives, is sometimes used to immediately produce back the damage; the debris is drawn out before it concentrates and solidifies. Such underbalance technologies are usually expensive, however, and therefore prohibitive in routine activities.

For a well that is a fracturing candidate, the near well damage caused by perforations is easily overcome by the induced fracture and does not adversely affect gas production. The cost of CCP is low compared to the sand jet perforation (SJP) described in the next section, and the process is also time effective. In most cases, CCP is adequate, and with powerful, deep penetration charges, the near wellbore tortuosity and pressure losses due to inefficient perforations are minimized. In high stress intervals, however, sometimes the CCP method will not be able to establish enough injectivity to perform fracture treatments. In these specific cases, the SJP process can be used to improve access between the wellbore and the formation. A field example case is provided in the next section, showing the benefits of the SJP.

Sand Jet Perforation (SJP)

SJP involves the use of high-pressure slurry (a combination of gel, surfactant, low mesh sand and brine) to perforate and penetrate the tubular and cement sheath, and consequently create a cavity in the formation. Pumping is conducted at a high differ- ential pressure, on the order of 2,500 psi, providing a velocity of about 600 ft per second across the cutting nozzles. The mechanism easily penetrates through tubular materials, cement sheath, and reservoir rock. Rock removal is caused by tensile failure, as the jetting is conducted below the compressive strength of the rock, avoiding compaction of the rock and thereby eliminating the possibility of lowered permeability. Specialized jetting tools and nozzles are required to provide the desired cavity in the formation.

One argument in favor of using this technique is that SJP achieves good vertical communication in horizontal wellbores, as well as easy initiation of hydraulic fractures. The perforations are smooth, and near well tortuosity and friction may be reduced. The cavities formed in the reservoir help in the faster cleanup of the well in the case of both fractured and unfractured wells. The method also eliminates the use of explosives, a much improved safety feature during operations that also reduces the potential for causing significant damage. The energy to perforate is incessant, as it is transferred to the formation through continuous injection of fluid and slurry.

The SJP technology is particularly suitable for strong rocks with high unconfined compressive strength (UCS) values. Due to the bigger opening of the rock, a rapidly increased proppant concentration schedule can be put in place when a well is perforated using SJP. It may take a particularly long time to perforate and slot the well, however, and the associated cost does not always make SJP attractive or competitive over the CCP techniques that are generally used in moderate strength rocks.

SJP Example: Well-A

Well-A is a vertical well drilled in a good permeability sand- stone section. It was initially perforated below the target interval with conventional shots across 40 ft. The intent was to induce an indirect fracture treatment through the perforation interval to connect the well to the more prolific interval 50 ft above. Direct perforation was avoided due to sanding possibility. During the initial DataFrac, several attempts to initiate a fracture turned out to be unsuccessful, as the injection pressure exceeded the tubular capacity without any indication of formation breakdown[6].

Figure 5 presents the pressure and rate profile of Well-A after conventional perforations. The dark blue and light blue lines in the figure represent the wellhead pressure response and the attempted injection rate profile, respectively. Consequently, the interval was sand jetted at the initial interval adding an additional 10 ft. The red and pink lines in Fig. 6 represent the wellhead pressure and injection rate profile, respectively, during post-jetting DataFrac treatment. These indicate that the breakdown of the formation has occurred, and a gain of about 2,000 psi in wellhead pressure was achieved.

Subsequent to the SJP treatment, the well was successfully fractured with more than 300,000 lbs

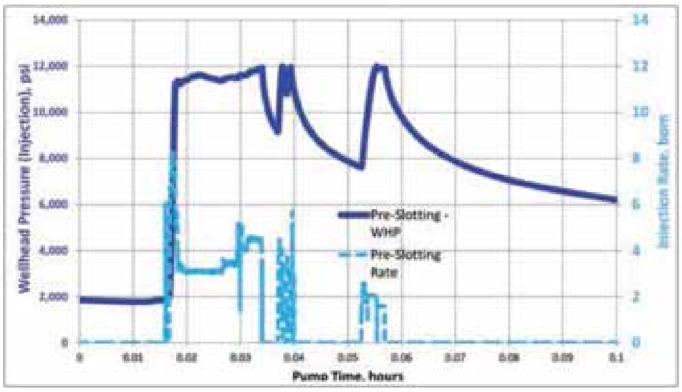

Fig. 5. Initial injection attempt after conventional perforation in Well-A.

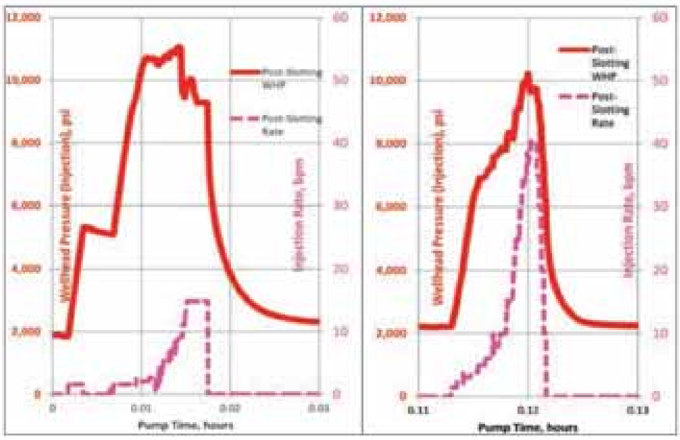

Fig. 6. Injection profile showing distinct formation breakdown and fracture extension post-SJP in Well-A.

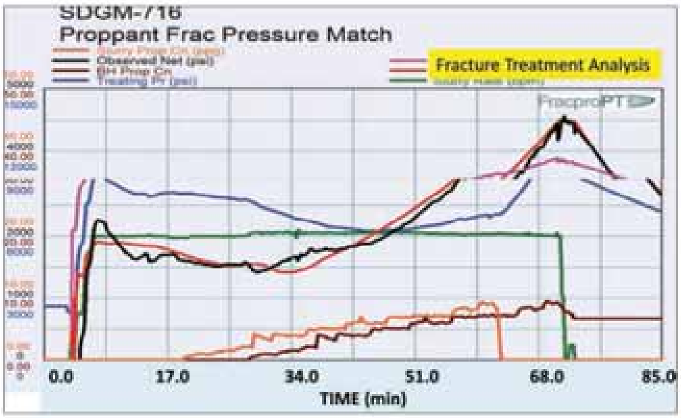

Fig. 7. Pump pressure match and injection profile for Well-A.

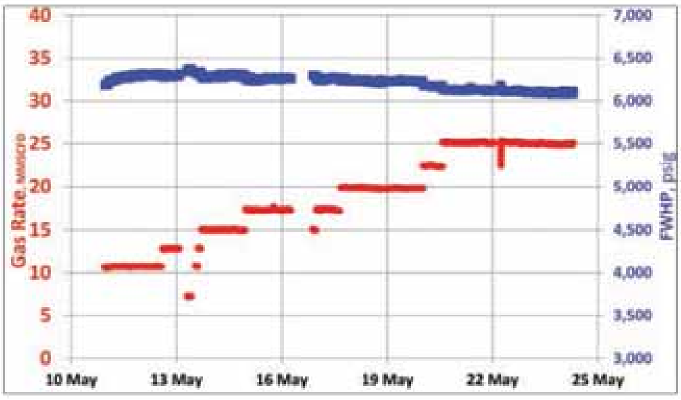

Fig. 10. Production test profile after SJP and fracturing in Well-A

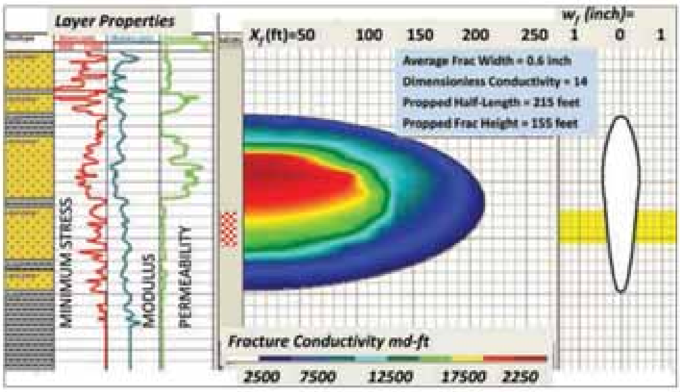

Fig. 8. Achieved fracture dimension and conductivity in Well-A.

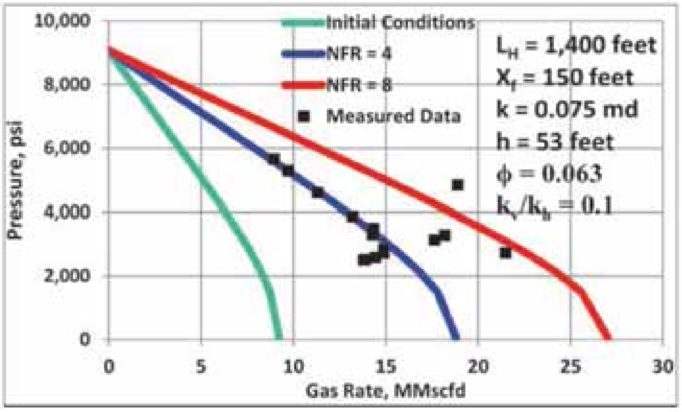

Fig. 11. Production test after stimulation treatment indicates fracturing results for Well-B in a tight reservoir.

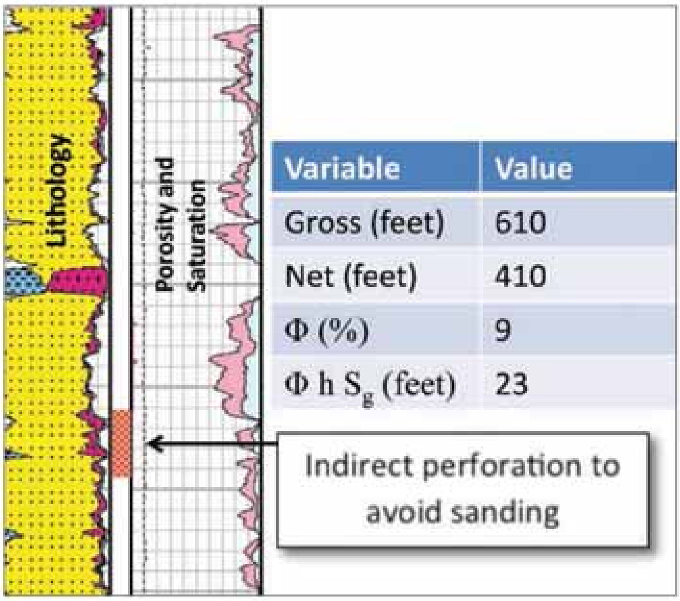

Fig. 9. Well-A formation lithology, porosity profile and perforation locations.

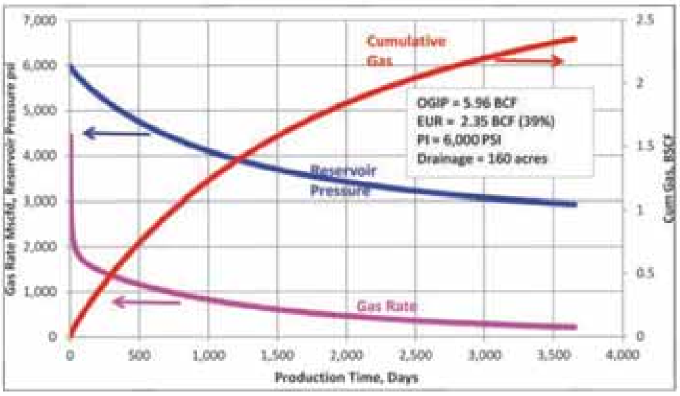

Fig. 12. 10-year flow performance shows about 2.4 BCF of cumulative production for Well-C.

of 20/40 and 16/30 mesh proppant types at a rate of 40 bpm. The treatment plot in Fig. 7 shows the proppant concentrations, wellhead pressures and bottom-hole pressures (BHPs), and injection rate, along with simulated match points to compute fracture dimension. Figure 8 presents the reservoir lithology, achieved propped fracture dimension and conductivity. The detailed formation lithology, porosity profile and fluid saturations, along with perforation locations are provided in Fig. 9. The high well performance and rate sustainability are indications of good reservoir quality, good wellbore/reservoir connectivity and a successful proppant fracturing, Fig. 10.

Tight Gas Reservoirs

A tight gas reservoir is defined as one that can neither be produced at economic flow rates nor recover economic volumes of natural gas unless a specified technique is used to stimulate production[7]. Depending on the reservoir rock properties, production from a tight gas reservoir can require either: (1) massive multiple hydraulic fracturing and/or (2) advanced drilling, such as horizontal or multilateral wells, to obtain maximum reservoir contact. Unconventional or tight gas has proven to be a large source of energy in every basin that produces a large quantity of hydrocarbons from conventional reservoirs. Optimal exploitation of tight gas needs to be studied and initiated for economic production.

It is well understood that regardless of how a stimulation job is executed, the rate and pressure at which a well produces depends entirely on the reservoir potential. Reservoir qualities, such as porosity, permeability, reservoir heterogeneity and layering, wellbore/reservoir connectivity, in-situ stress, etc., are some of the most important parameters used to predict well performance. As such, petrophysical evaluation and an under- standing of the reservoir's flow and geomechanical properties are essential. In addition, the GIP and in-situ stress direction determine the number of wells to be drilled, the well spacing, the well azimuth and the hydraulic fracturing strategy needed to efficiently exploit a reservoir. Estimated ultimate recovery (EUR) helps in performing economic analyses so that realistic expectations can be set in terms of drilling and well performance prior to reservoir development.

Example Wells: Well-B and Well-C

The inflow performance rate (IPR) plot from a tight gas example, Well-B, is presented in Fig. 116. The well, initially drilled as a vertical well, tested about 8 million standard cubic feet per day (MMscfd) at 1,900 psi after hydraulic fracture treatment. The well was subsequently sidetracked, with a reservoir contact of 1,400 ft, completed with a MSF completion and successfully fractured in four stages. Under the initial well conditions (unfractured), the well was expected to produce at about 7 MM- scfd at 3,000 psi BHP. The actual measured production data after fracture treatment was matched with the predicted results of four transverse fractures (blue curve, Fig. 11). An additional run was made with eight fractures (red curve) to show that the well rate could have further improved; however, the major assumptions in prediction runs are that the reservoir and fracture properties stay constant, reservoir homogeneity is maintained throughout the drainage area, fracture treatment is implemented as designed, and post-treatment cleanup restores 80% of the original proppant conductivity.

Another actual example is Well-C is from a tight gas reservoir[6]. In this case, the reservoir pressure was lower than that of Well-B, and the formation quality was also much poorer. The post-fracture history matching showed two decent hydraulic fractures. The long-term production forecast for Well-C, performed using an analytical model and illustrated in Fig. 12, predicts about 2.4 billion cubic ft (BCF) of produced gas in 10 years. The EUR depends on the reservoir properties as well as wellbore configuration, well spacing and hydraulic fracturing characteristics.

Both Well-A and Well-B are expected to yield better performance once the fracture is properly cleaned up. The remainder of the fracture gel residue will still hamper the well performances, as will be illustrated later.

Hydraulic Fracturing

Although most moderate and tight gas wells are treated with hydraulic fracturing on a routine basis, it takes tremendous effort to optimize and conduct successful fracture treatments, where effective multiple fractures are placed in the reservoir and the post-treatment rates fall within expectations. A fracture design that is expected to improve the well rate by a certain factor must consider the "true fracture" dimensions and conductivity, which ultimately contribute to flow increase. Numerous factors can effect stimulation treatments so they do not work as designed and envisioned, resulting in the underperformance of a well. These factors and their related remedies are addressed in the following sections.

Fracture Dimensions

An important parameter in fracture dimension that

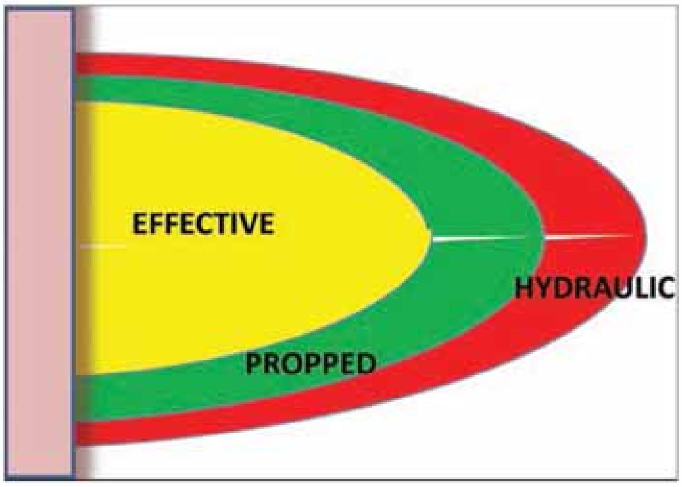

Fig. 13. Illustration of Xe, Xp and Xh indicating how $X_e < X_p < X_h$.

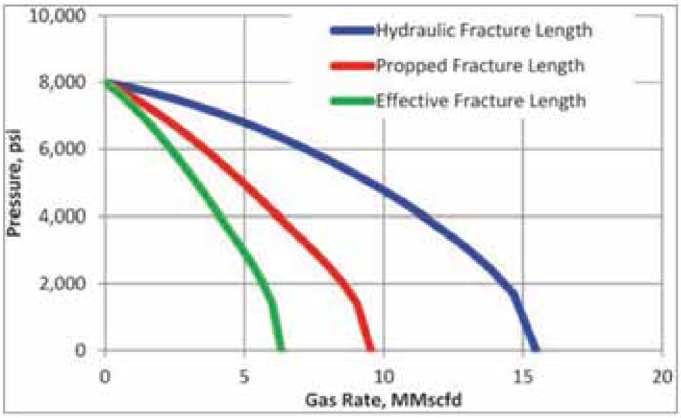

Fig. 14. Well potential as a function of X_f.

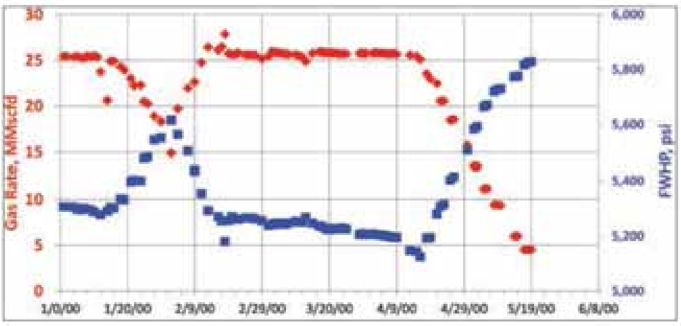

Fig. 15. Post-treatment performance of Well-D.

X_f	H_{NET}
feet	
200	100
125	75
75	50

Table 1. Reservoir and fracture properties (kh=10 md-ft).

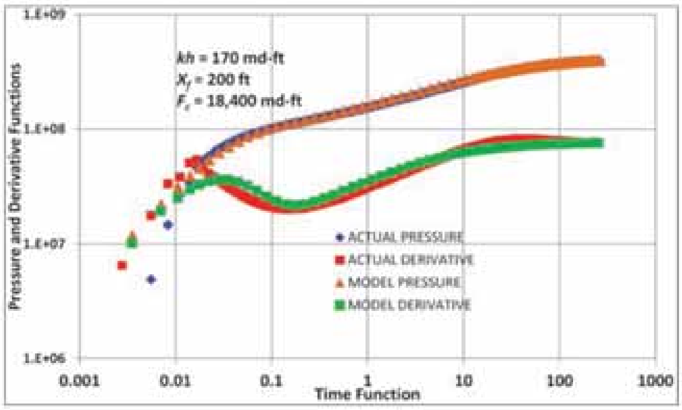

Fig. 16. Post-treatment PBU test on Well-D.

contributes to well performance, other than fracture conductivity, is the effective fracture length (X_e), Fig. 13. Large discrepancies in fracture half-lengths among created fractures (also known as hydraulic fracture length, X_h), propped fractures (X_p) and X_e can cause the post-fracture flow rate to be lower than predicted[6]. The created fracture length is the fracture volume generated during pumping, based on the fluid volume balance (V_{pump} - V_{loss}) reached at the end of the job with the shutting down of the injection pumps. Determining the propped fracture length depends on the created volume and the pumped proppant mass. With good proppant transport and fluid quality assurance, a simple mass balance can provide the approximate fracture area coverage by the proppant, provided the correct stress profiles of Young's modulus are used to calculate the fracture height and width. The effective fracture geometry, which is the most important parameter since it dictates the post-treatment rate of the well, depends not only on proppant placement, but also on cleanup efficiency, residual gel damage and proppant conductivity losses due to embedment or crushing. An optimal fracturing job therefore requires scrupulous quality control and thorough post-stimulation cleanup. Well performance is directly propor- tional to effective fracture geometry. Figure 13 illustrates the possible scenario that generally occurs where $X_h > X_p > X_e$. The IPR plots illustrated in Fig. 14, which correspond to the reser- voir and fracture properties in Table 1, show how fracture half-lengths affect production rate. The impact of the effective fracture length on well performance is more pronounced in low permeability wells.

Good Proppant Transport Example, Well-D

Well-D, drilled in a good permeability sandstone reservoir, was successfully fractured with 220,000 lbs of proppant. The job went as per design, and a post-treatment stabilized rate of 25 MMscfd was achieved, Fig. 15. The pressure buildup test presented in Fig.

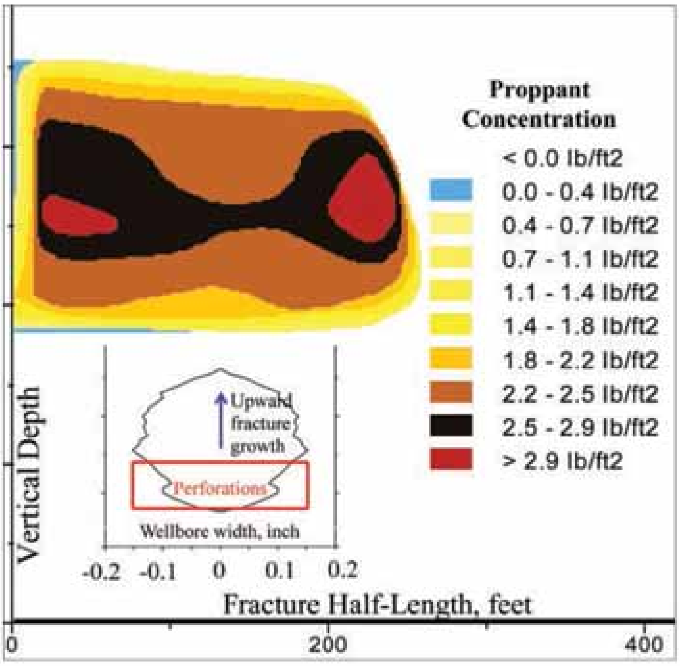

Fig. 17. Fracture geometry from pumping pressure match of Well-D.

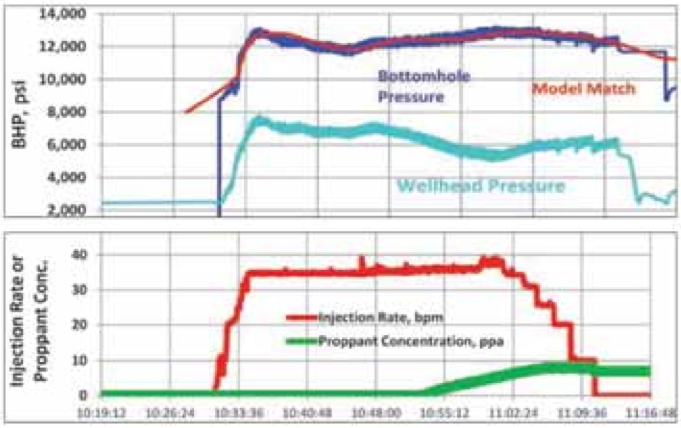

Fig. 18. Fracture treatment plot for Well-D..

Fluids	Main Components	Advantages / Disadvantages
Conventional Linear Gel	Polymer: Hydroxypropyl Guar (HPG) Carboxymethyl Guar (CMHPG) → These are dry polymers that swell up on hydration to form viscous gel	Poor proppant carrying capacity and high fluid loss Easier cleanup
Borate Cross-Linked	Guar of HPG, CMHPG and Hydroxyethyl Cellulose (HEC) →Use of Borate ions to cross-link hydrated polymers	Reversible (re-crosslink after shear degradation) – easy to break therefore gel regained permeability Stable and good transport capacity Requires hi gel pH (9-12) for viscosity yield →By far the most used fluid
Organo Metallic Cross-Linked	Titarate and Zirconate complexes of Guar	Extremely stable at high BHT (>300°) in acidic, alkaline or neutral pH fluid conditions →Shear sensitive and not reversible →Difficult to break Can cause high formation damage

Table 2. Different fracturing fluids and their advantages and disadvantages.

16 indicated near-infinite fracture conductivity with 200 ft of effective fracture half-length. The treatment pressure match, using a hydraulic fracture model, showed a propped fracture half-length of 250 ft. This is an excellent example where the effective fracture half-length was comparable with the propped fracture half-length derived from a pressure match and mass balance, so the expected rate performance compared closely with the actual performance of the well. Figures 17 and 18 present the propped fracture geometry from the injection pressure match for Well-D.

Fracturing Fluids

Fluid compatibility is a key issue in the final fracture design. Partially deteriorated or incompatible fluids, under-designed fluid additives, use of a higher polymer loading than required and other critical factors can cause formation damage, fracture conductivity reduction or premature screen-out, all leading to loss of well potential. The most important factors to be considered in selecting fluids are fluid loss properties, fluid stability under reservoir conditions (temperature and pressure), compatibility with formation fluids, friction loss,

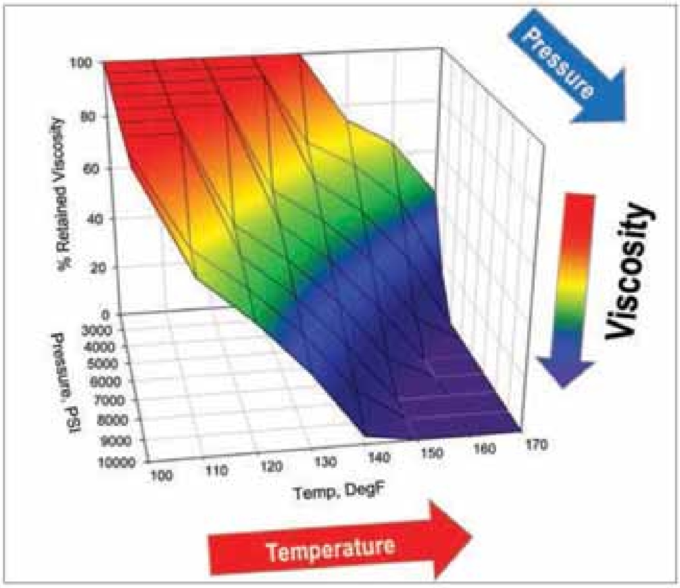

Fig. 19. Fluid behavior under temperature and pressure[9]

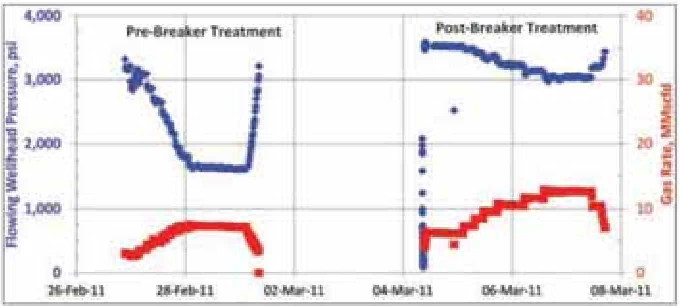

Fig. 20. Well-E performance before and after good cleanup.

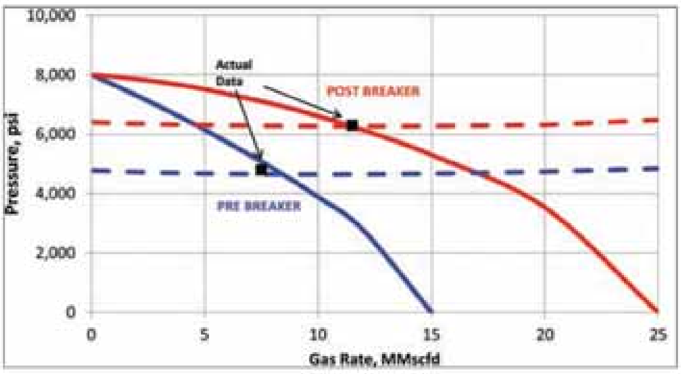

Fig. 21. Improved Well-E IPR after additional gel breaker treatment.

regained permeability (formation damage), proppant transport capability, and final fracture conductivity. More than 50 different fracturing fluids are available to address different reservoir issues during stimulation. The main types are provided in Table 28.

Pumping pressures encountered during fracturing can degrade borate crosslinked fluid viscosity[9]. The loss in fluid integrity can be negligible to complete, depending on the fluid formulation, temperature and pressure. The most recent study showing the loss of fluid viscosity as

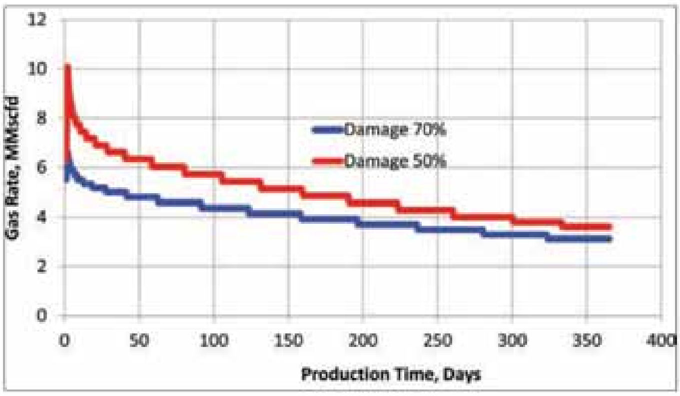

Fig. 22. Long-term production impairment due to improper cleanup in Well-F[6,10].

functions of pressure and temperature is illustrated in Fig. 19. It is therefore important to consider rheology behavior when selecting the fluid, per the functions of the reservoir and pumping conditions.

The pump volume for each stage is optimized based on reservoir properties, proppant volume and proppant concentration. The pad volume depends on the leakoff and must generate enough width before the proppant reaches the fracture.

Insufficient pad volume or rapidly degrading fluid under reservoir conditions will cause premature screen out. Over-designing the flush stage with the intent to displace all the proppant from the wellbore and into the fracture will lead to poor wellbore and fracture connectivity, and thereby significantly reduce gas flow.

Post-Fracture Cleanup

Excellent fracture fluid cleanup is required to restore proppant conductivity; otherwise it will lead to damage in the proppant pack and significantly decrease well productivity. The cleanup process can be improved with the use of: (1) a good fluid recipe (low gel loading and cross-linker concentration in addition to sufficient breaker and surfactants), and (2) quick cleanup practices after the treatment is over. If a well is not cleaned up properly, significant gel damage may occur, and proppant conductivity will be reduced permanently.

Figure 20 presents well performance profiles of an actual well, Well-E, drilled in tight sandstone, where the initial cleanup after fracture treatment was not sufficient[6]. The post-treatment well performance was gauged against reservoir characteristics and expected fracture geometry, and it was immediately concluded that the actual rate was below expectation. Since the fracture treatment had been pumped as designed, it was suspected that the proppant pack was damaged due to insufficient cleanup of the well. Consequently, a much stronger live gel breaker at a higher concentration along with a surfac- tant was re-injected into the well. After waiting for the reaction to occur, the well was opened for cleanup. At this time, a much higher flow rate at a higher wellhead pressure was obtained, which was comparable to the expected well performance. Both pre- and post-breaker performance points were matched, which showed, Fig. 21, that well IPR more than doubled as a result of the treatment. This actual example illustrates the two major components of a successful well stimulation process: (1) good estimation of well performance, which requires proper knowledge of the reservoir and fracture properties, and (2) identification of the cause of the problem (in cases where the well performance falls below expectations), determining remedial actions and applying necessary treatment to restore productivity.

A similar problem happened with Well-F, where the well rate fell far below predicted post-fracture performance. Similar to Well-D of the previous example, Well-F was a vertical well drilled in a low permeability interval, and it had been successfully perforated and fractured with 250,000 lbs of proppant. The initial post-fracture test rate was matched with a numerical simulator only by reducing the well's proppant conductivity by 73%. This reduction in proppant conductivity was caused by the residual gel damage that did not flow back to the surface during cleanup. Figure 22 presents a 1-year gas rate profile for Well-F with a 70% and 50% loss of proppant conductivity[6,10]. In actuality, the industry average for proppant conductivity after successful treatment and cleanup is about 80% of the theoretical permeability. This means that conductivity degradation, due to gel damage or any other factor, 20% or less, is within the tolerance criterion. Figure 23 shows that in a 1-year period, a gain in cumulative production of about 25% can be achieved if Well-F is initially cleaned up and has 80% of its proppant conductivity restored.

Selection of Perforation Interval

Improper placement of perforations can cause the fracture to grow outside the reservoir interval. For indirect fracture treatments, often chosen to avoid perforating high sanding intervals, perforations are sometimes placed above the zone of interest to avoid sanding. In such cases, high net pressure at the end of pumping must be built to maintain the connectivity of the perforated interval with the main gas section and to avoid creating pinch-outs due to proppant settlement.

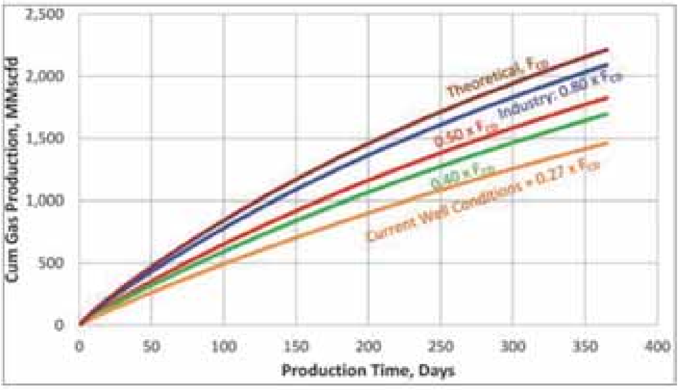

Fig. 23. Cumulative production after cleanup.

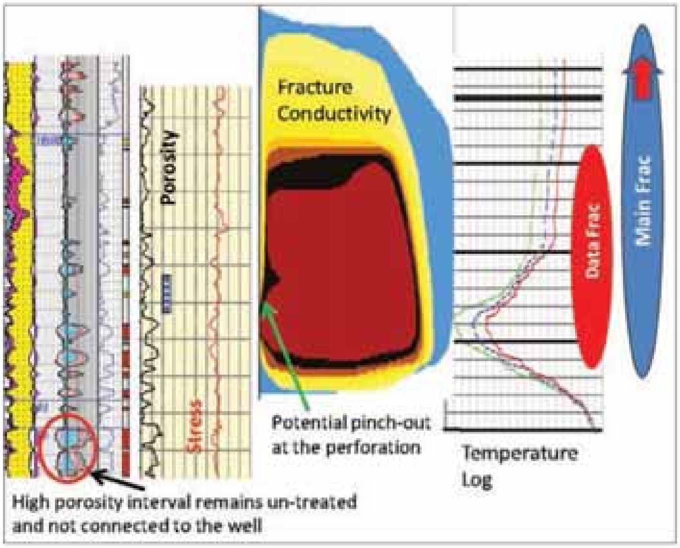

Fig. 24. Pinch out and fracture growth affecting fracture effectiveness in Well-G.

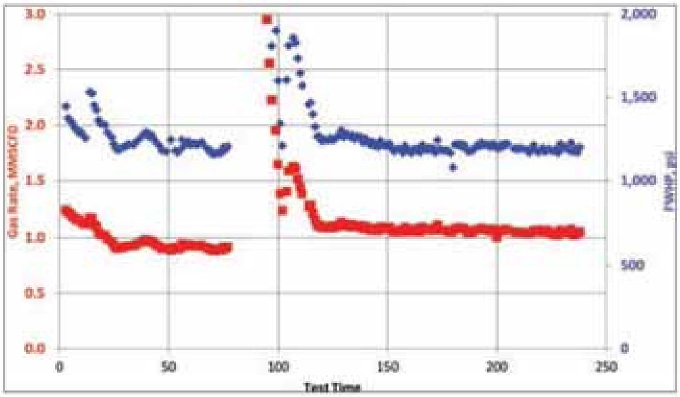

Fig. 25. Post-fracture test results confirm poor fracture placement for Well-G.

An example provided in Fig. 24, Well-G, shows that although the fracture propagated below the perforations and covered some of the high porosity intervals, a pinch-out occurred in the perforated interval due to proppant settlement[6]. This settlement was caused by high stress in the perforated interval as well as the low net pressure achieved at the end of the job, resulting

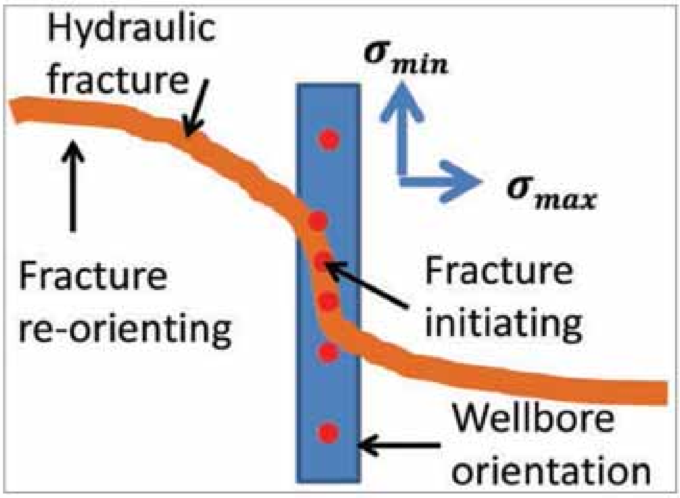

Fig. 26. Possible T-shape fracture for wells oriented toward $\square_{min}$.

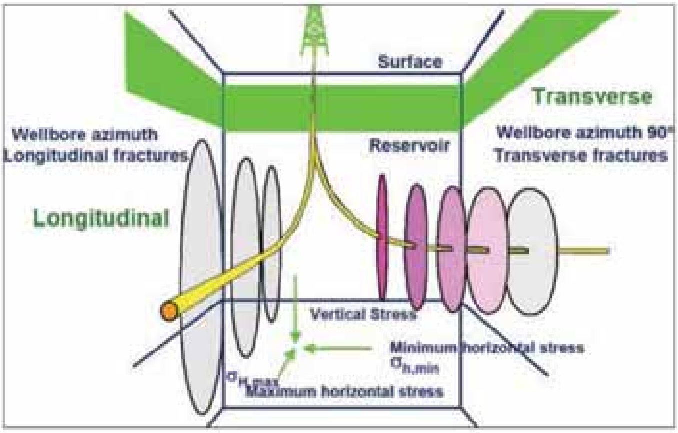

Fig. 28. Fracture development as a function of wellbore orientation (after Economides).

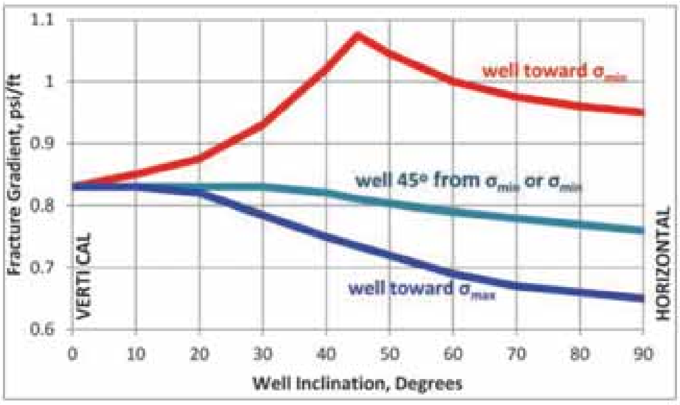

Fig. 27. Fracture initiation pressure as a function of wellbore orientation[11].

in insufficient packing of the proppant. The decreasing pressure response observed in the pump pressure profile also indicates growth in fracture height, in this case more in the upward direction, which caused more proppant to be lost in the nonproductive zone. The two bottommost high permeability intervals indicated in the figure were not covered by the fracture. Although the entire treatment was successfully pumped, placing all the proppant inside the formation, the well only produced about 1 MMscfd, much below expectations, Fig. 25. To overcome the poor well performance, remedial action to re-treat the reservoir is being designed. For indirect fracture treatments, placing perforations below the zone of interest is usually a better option[6]. In this scenario, even with the proppant settlement, the connection of the fracture with the non-perforated higher productivity zone is better maintained with such placement.

Wellbore Trajectory

Wells that are drilled parallel to $\square_{max}$ will not favor creation of transverse or orthogonal fractures. In such a case, the number of hydraulic fractures that can be created is reduced significantly. That is because when a well is placed along the maximum in-situ stress direction, the induced fractures are created in the same direction, limiting the number of independent fractures that realistically can be placed without one fracture overlapping the adjacent one. It is therefore conceivable that only between two and four fractures can be placed longitudinally in a wellbore that is more than 1,000 ft long, while there is practically no limitation on the number of orthogonal fractures generated from wellbores perpendicular to $\square_{max}$. Subsequently, the optimal number of fractures is not necessarily the largest number; rather it is dictated by the reservoir flow capacity, wellbore trajectory, reservoir contact, and completion limitation.

The well azimuth and inclination may impact the fracture initiation pressure. When a wellbore is drilled in the direction of the least horizontal stress, T-shaped fractures are likely to occur, Fig. 26. This is because the tensile zone created around the wellbore in the direction of $\square_{max}$ causes the fracture to initiate in $\square_{min}$ direction, but soon the fracture turns, the propagating axis changes, and the fracture develops toward $\square_{max}$ direction. Figure 27 shows that the maximum initiation pressure is reached in a well that is 45° deviated and drilled toward $\square_{min}$[11]. A 15% increase in breakdown pressure can occur for a horizontal well drilled toward min compared to a vertical well. Proper tubular ratings are therefore needed to fracture a high stress formation having horizontal wells with an azimuth toward $\square_{min}$.

The fracture orientation with reference to the wellbore is presented schematically in Fig. 28. It should be noted that to get production impact from horizontal wells with multiple fractures, each fracture has to be of sufficient length and conductivity, and each needs to be properly cleaned up after treatment. The placement and total number of fractures should minimize in- terference between fractures. This requires good reservoir knowledge, proper planning and design of fracture treatment, and proper implementation. If placing more fractures causes interference, then the number of fractures should be optimized. Reservoir isotropy and homogeneity will impact well perform- ance and ultimate recovery.

Conclusions and Recommendations

1. In-depth reservoir characterization and optimal fracture design are needed to predict a realistic gas rate and cumulative recovery.

2. The gap between expected well performance and what actually occurs can be minimized by using an appropriate reservoir model, implementing good fracturing practices and ensuring complete cleanup.

3. Selecting the correct fracture fluids is essential for a treatment to be successful. Correct gel loading, breaker concentration and addition of surfactants will enhance fluid flow back after treatment.

4. Improper cleanup reduces fracture conductivity and can significantly impact well rate and recovery.

5. Sand jetting can sometimes be used to improve communication between the wellbore and the formation.

6. In indirect fracturing treatments, care must be taken to ensure good connectivity between fracture and wellbore. Pinch-outs and proppant settlement will negatively impact the gas rate.

7. Multiple fracturing stages can be induced when wells are drilled toward the minimum in-situ stress direction. Higher fracture initiation pressure can be expected in such a configuration.

Acknowledgements

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Biographies

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Rahim has authored 55 Society of Petroleum Engineers (SPE) papers and numerous in-house technical documents. He is a member of SPE and a technical editor for the Journal of Petroleum Science and Engineering (JPSE). Rahim is a registered Professional Engineer in the State of Texas and a mentor for Saudi Aramco's Technologist Development Program (TDP). He is an instructor for the Reservoir Stimulation and Hydraulic Fracturing course for the Upstream Professional Development Center (UPDC) of Saudi Aramco.

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In 1994, Hamoud received his BS degree in Chemical Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia, and in 1999 and 2003, he received his MS and PhD. degrees, respectively, in Petroleum Engineering, both from the University of Texas at Austin, Austin, TX.

Adnan A. Al-Kanaan is the General Supervisor for the Gas Reservoir Management Division, where he heads a team of more than 30 petroleum engineering professionals working to meet the Kingdom's increasing gas demand for its internal consumption.

He started his career at the Saudi Shell Petrochemical Company as a Senior Process Engineer. Adnan then joined Saudi Aramco in 1997 and was an integral part of the technical team responsible for the on-time initiation of the Hawiyah and Haradh Gas Plants, two major plants that currently process 6 billion cubic feet (BCF) of gas per day. He also manages Karan and Wasit, the two giant offshore gas increment projects, with expected total production capacity of 5.5 BCF of gas per day.

Adnan has 14 years of diversified experience in reservoir management, field development, reserves assessment, gas production engineering and mentoring young professionals. His areas of interest include reservoir engineering, well test analysis, reservoir characterization and reservoir development planning.

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Before joining Saudi Aramco, Nejla worked for the Alberta Research Council for 2 years and at Exxon (in its subsidiary Esso Resources Canada) as a Reservoir Engineer for 4 years.

She received her BS degree in Chemical Engineering from Ankara University, Ankara, Turkey, and her MS degree in Chemical Engineering from the University of Alberta, Edmonton, Alberta, Canada.

She is a certified Petroleum Engineer in Canada and has been a member of the Society of Petroleum Engineers (SPE) since 1978.

Daniel Kalinin is the Schlumberger Reservoir Stimulation Domain Manager based in al-Khobar, Saudi Arabia. He is responsible for the integration of Schlumberger expertise in reservoir evaluation and charac- terization into fracturing and stimulation in Saudi Arabia, Bahrain and Kuwait. Before coming to Saudi Arabia in 2009, Daniel was involved in G&G support of the Chicontepec integrated well construction project in Mexico, carbonate stimulation in Kazakhstan, and development of a stimulation activity in Turkmenistan and Uzbekistan. He took part in the start of the fracturing boom in Russia in the late 1990s. Before joining Schlumberger in 1999, he worked for a joint venture of Canadian Fracmaster in Western Siberia.

Daniel received his BS degree in Structural Geology from Novosibirsk State University, Novosibirsk, Russia, in 1993, and another degree in Economics from Tomsk State University of Architecture and Construction, Tomsk, Russia. He also attended various post-grad programs at the University of Tulsa, Tulsa, OK, and the Imperial College, London, U.K.

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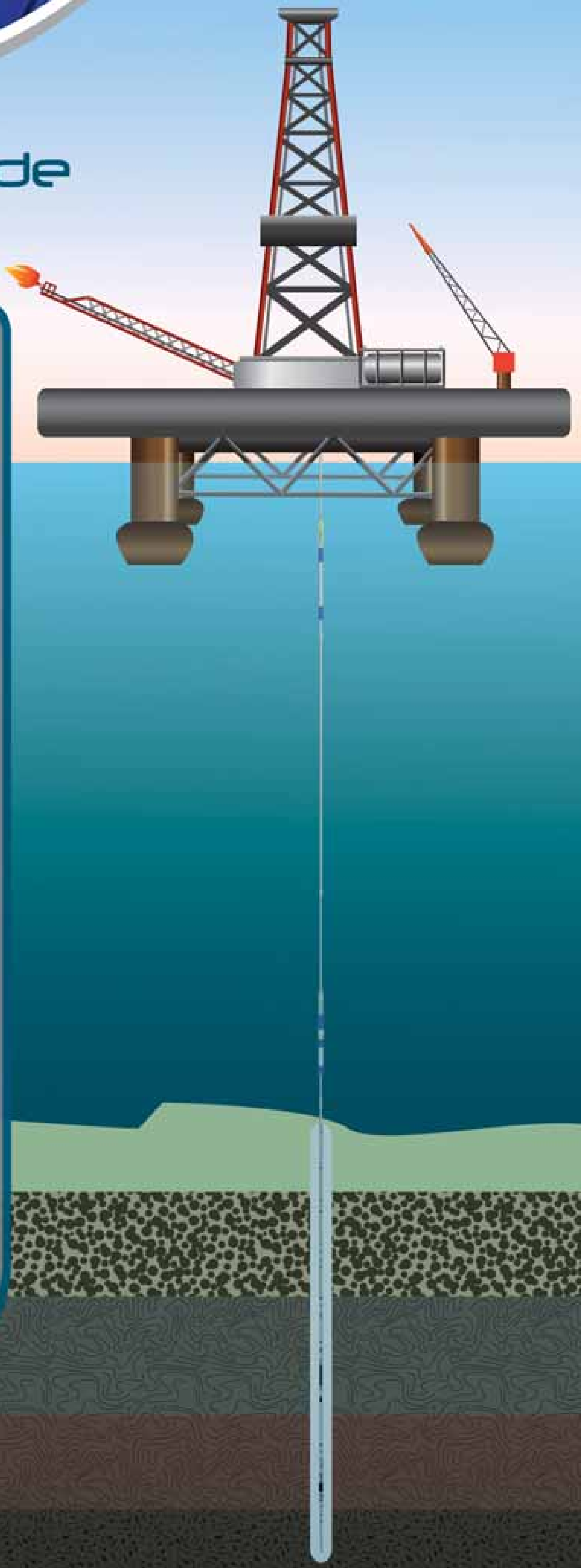

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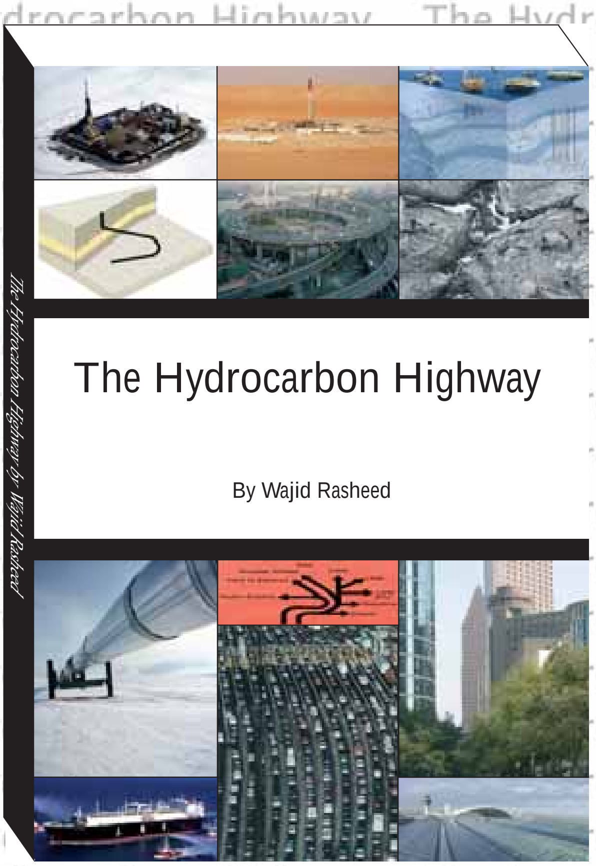

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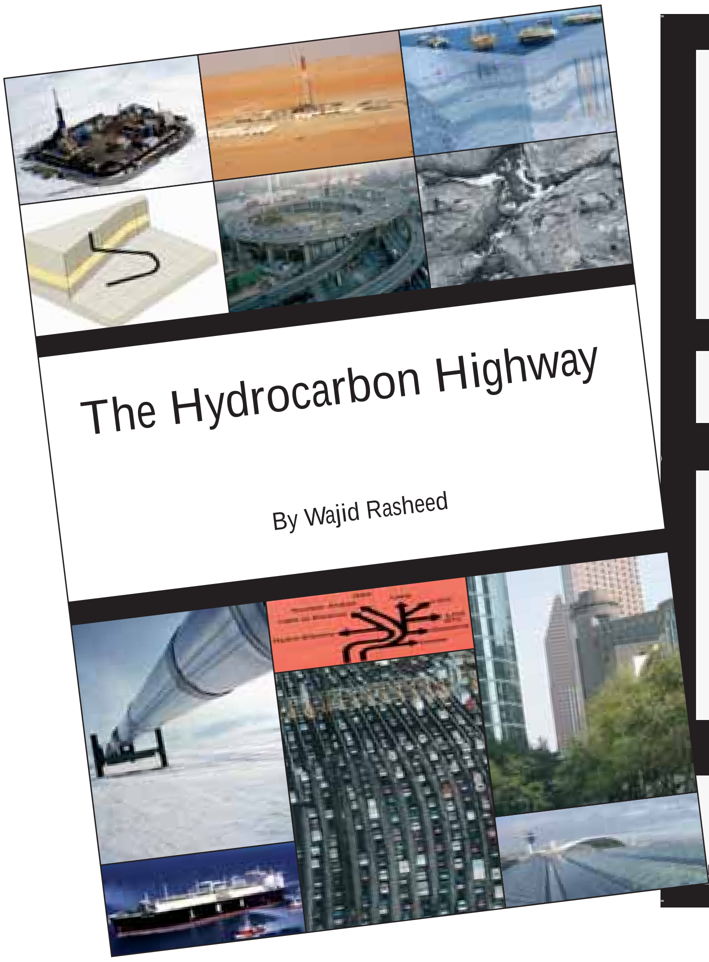
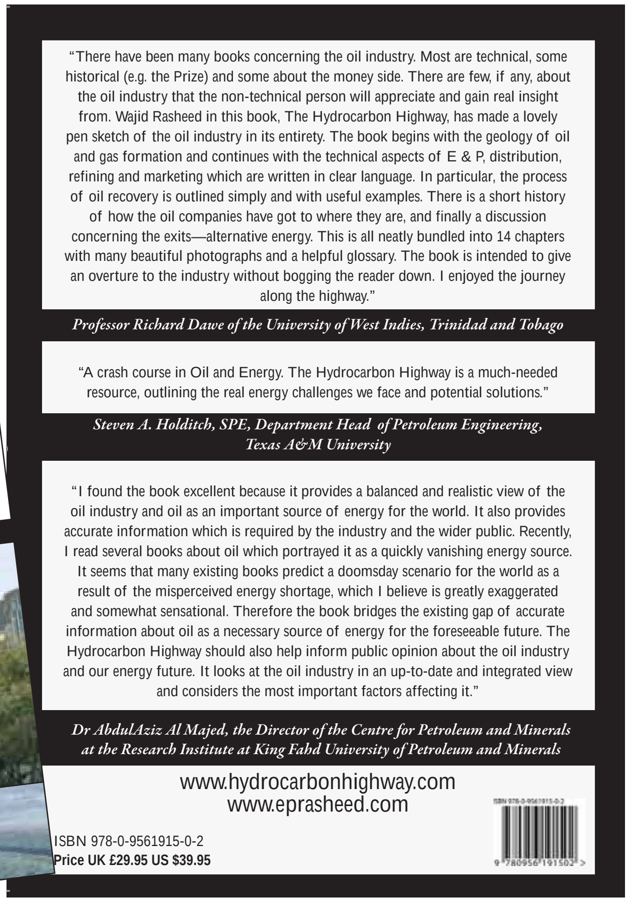
Refining

A Chapter from The Hydrocarbon Highway, by Wajid Rasheed




"There have been many books concerning the oil industry. Most are technical, some historical (e.g. the Prize) and some about the money side. There are few, if any, about the oil industry that the non-technical person will appreciate and gain real insight from. Wajid Rasheed in this book, The Hydrocarbon Highway, has made a lovely pen sketch of the oil industry in its entirety. The book begins with the geology of oil and gas formation and continues with the technical aspects of E & P, distribution, refining and marketing which are written in clear language. In particular, the process of oil recovery is outlined simply and with useful examples. There is a short history of how the oil companies have got to where they are, and finally a discussion concerning the exits—alternative energy. This is all neatly bundled into 14 chapters with many beautiful photographs and a helpful glossary. The book is intended to give an overture to the industry without bogging the reader down. I enjoyed the journey along the highway."

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Dr AbdulAziz Al Majed, the Director of the Centre for Petroleum and Minerals at the Research Institute at King Fahd University of Petroleum and Minerals

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The downstream process of refining is an essential step in adding value to crude oil and creating different products made from oil and gas. An understanding of how such products are used in hydrocarbon applications is the basis of the supply and demand equation which ultimately defines exits from the Hydrocarbon Highway.

Picky Refineries

Refineries are designed and configured to handle a specific basket of crude, with a distinct preference for sweet and light. Over time, meeting this specific demand becomes difficult as production from original fields serving the refinery declines and new sources and new types of crude must be found to keep the refinery going. Oil companies have several options to keep production steady. They can find crude through the

Homologous Series	General Formula	Example	Functional Group
Alkanes	C_nH_{2n+2} $(n \geq 1)$	CH_4, $n = 1$	
Alkyl	C_nH_{2n+1} $(n \geq 1)$	CH_3, $n = 1$	
Alkenes and Cyclic Alkanes	C_nH_{2n} $(n \geq 2)$	C_2H_4, $n = 2$	$C = C$
Alkynes	C_nH_{2n-2} $(n \geq 2)$	C_2H_2, $n = 2$	$C \equiv C$
Alcohols	$C_nH_{2n+1}OH$ $(n \geq 1)$	CH_4O, $n = 1$	- OH
Carboxylic acids	$C_nH_{2n}O_2$ $(n \geq 1)$	CH_2O_2, $n = 1$	- COOH
Carbohydrates	$C_n(H_2O)_n$ $(n \geq 1)$	$C_6H_{12}O_6$	

Where n represents the number of carbon atoms present.

Table 1 - Homologous Series

drill-bit, by acquiring competitors or by buying barrels. Only the last two allow some degree of control, but no guarantee of crude blends. Heavy oil from areas such as Canada and Venezuela, for example, cannot be refined at most refineries.

PdVSA (the Venezuelan National Oil Company [NOC]) was able to enter the US refining and distribution market as can be noted by the many 'CITGO – Cities Services' gas stations in the South. The spread of refining options enabled PdVSA to swap and trade crudes so that its own refineries could function more efficiently. This is because its heavy oil could only be refined at a single location. PdVSA's purchase of CITGO basically 'guaranteed' a market for Venezuelan crudes through its swaps and trades.

The bulk of global refineries are found mainly in consuming rather than producing countries which involves the costly transportation of crude or unrefined hydrocarbons[1]. This is a paradox because it would be far more efficient and far less costly to refine products near the source and transport the more valuable refined products to their various markets. It would also provide valuable jobs for producing countries. In addition, positioning refineries in densely populated consumer nations is problematic because of environmental concerns and the 'nimby' ('not in my back yard') factor.

Hydrocarbons*, as we have seen in *Chapter 3: What's in a Wet Barrel?*, are made up of different arrangements of volatile hydrogen and carbon compounds held together by weak Van der Waals forces. Variations in the strength and number of inter-molecular bonds, along with impurities, determine the viscosity and the melting and boiling points of most hydrocarbon compounds[2]. The stronger these forces and bonds, the heavier or more viscous the oil will be. As viscosity increases, more kinetic energy is needed to overcome the intermolecular forces holding the hydrogen and carbon together. For this reason, heavy oil is also less flammable as its compounds are less volatile, again due to increased intermolecular forces. The reverse also applies with much weaker forces hold together gas. Illustrating this are the two extremes of the hydrocarbon scale: methane gas (CH_4) and asphaltene ($C_{80}H_{162+}$)[3].

Homologous Series

In Chapter 3, we also saw that certain hydrocarbon compounds share the same general molecular formula. They form part of the homologous series as seen in Table 1. Alkanes (or paraffins) are saturated hydrocarbons that form the basis of most crude oil and natural gas. They have single bonds and are described by the general formula (C_nH_{2n+2})[4].

Alkanes cover the spectrum of petroleum from methane, ethane, propane, butane (aerosol propellants) and pentane to octane (gasoline), nonane (diesel and aviation fuel), hexadecane (fuel oil) and tetracontane (lubricating

... positioning refineries in densely populated consumer nations is problematic because of environmental concerns and the 'nimby' ('not in my back yard') factor.

oil). Hydrocarbons that contain 35 or more carbon atoms are generally classed as bitumen, asphalt and tar. By far the most important end use of alkanes is combustion as fuel to provide heat and electric or motive power. In most cases, complete oxidation is not achieved, and varying amounts of incompletely oxidised fragments, carbon monoxide, and elemental carbons are produced[5].

Alkenes

Alkenes are unsaturated hydrocarbons. They have a double carbon bond and are characterised by the formula C_nH_2. The simplest alkene is ethene (C_2H_4) and it is often created by the steam cracking of Liquefied Petroleum Gas (LPG), ethane and light naphtha.

Ethylenes are used extensively as feedstock in many industrial products. They form the basis of plastics (polyethylene, polypropylene, polystyrene and polyvinylchloride or PVC) and industrial alcohol (ethanol). Alkenes themselves can also be produced by the dehydration of alcohol – see the production of ethanol in Chapter 13: Renewable Energy.

Alkenes are not found in crude oil and are one of the most valuable types of organic molecules in the chemical industry[6].

Cracking involves heating some of the less used fractions to a high temperature vapour and passing them over a suitable hot catalyst. The main products from cracking alkanes from oil are smaller alkanes (e.g. for petrol or diesel) and alkenes (e.g. for plastics).

Arenes

Arenes (or aromatics) are also unsaturated hydrocarbons, but they are characterised by a cyclic arrangement of six carbon atoms, the simplest of which is benzene (C_6H_6). Aromatics give rise to various pharmaceutical products, solvents and paints such as paracetamol (C_6H_4) and toluene (C_6H_5-CH_3)[7].

Fractional Distillation

Refineries will distill hydrocarbons into fractions according to their volatility; the most commonly known is petroleum spirit or gasoline. Fuels obtained during the refining process are LPG, naphtha, kerosene, gas-oil and fuel oil. Non-fuel products such as lubricants and asphalt (used in paving roads) can also be obtained during refining. After distillation, however, it is common for refined fractions not to match their commercial demands. Automotive fractions such as petrol and diesel are in great demand so heavier fractions such as heavy naphtha, gas-oil or bitumen are subjected to secondary refining.

Cracking describes the process where heavier fractions are broken down to produce more of the lighter automotive fractions. Catalysts such as zeolite are commonly used to accelerate the cracking process and

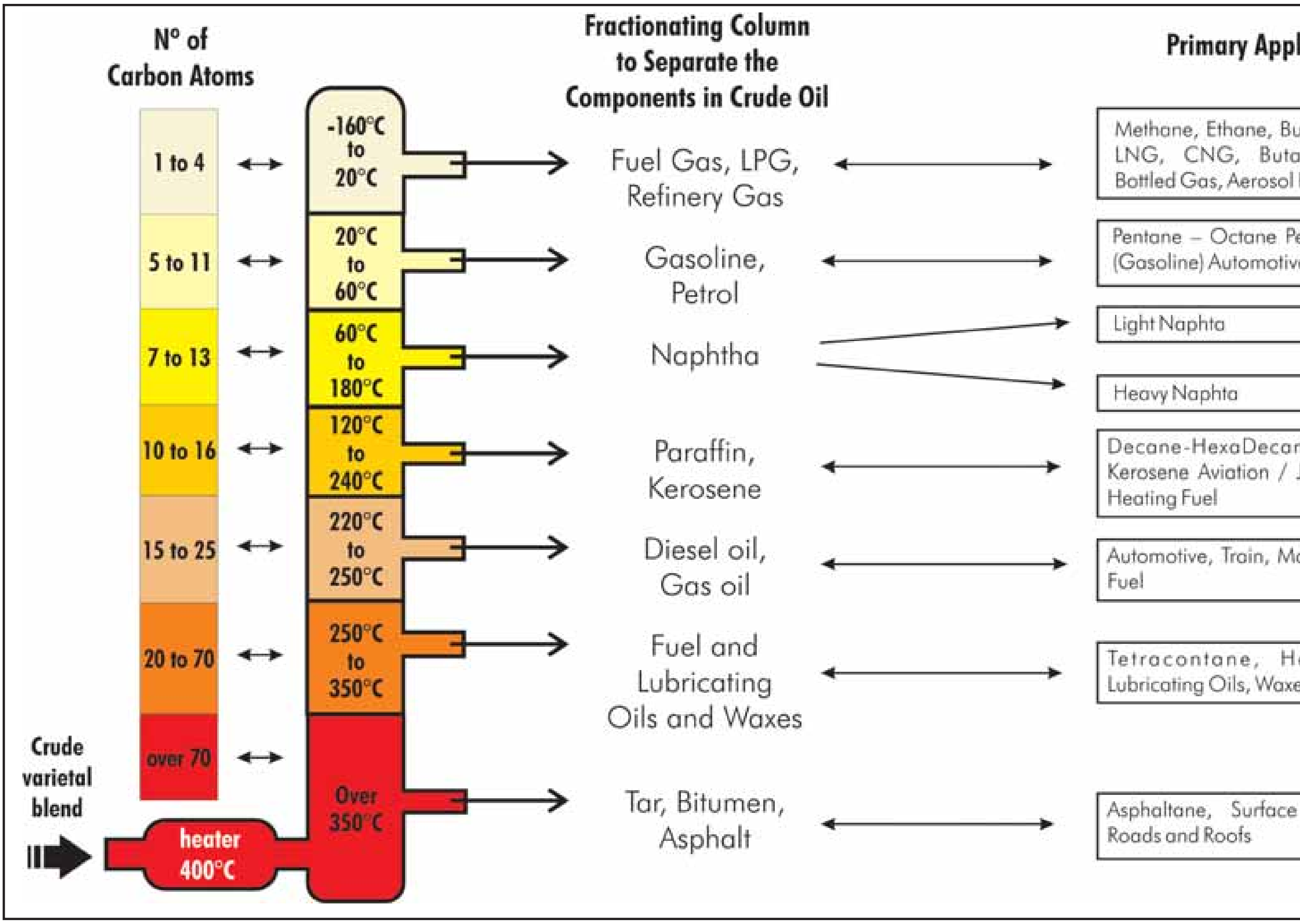


Figure 1 - The Fractional Distillation of Crude Oil and Gas (EPRasheed)

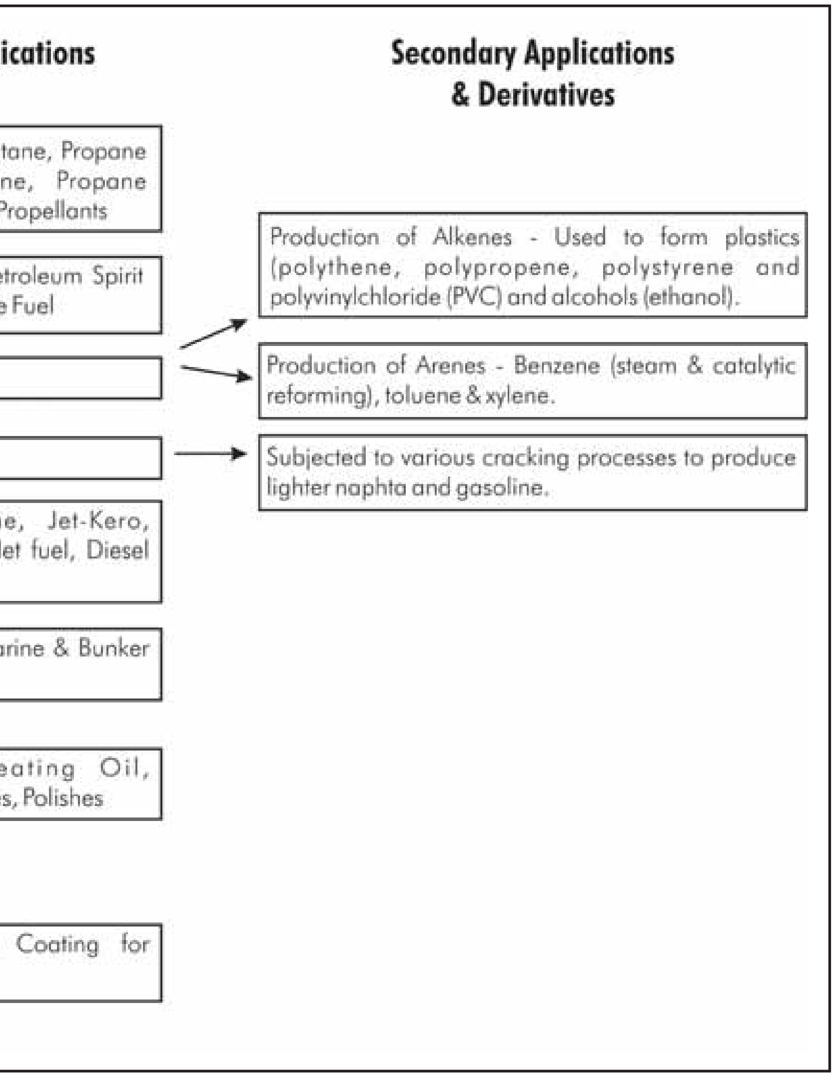
variations in cracking configurations exist according to the feedstock and final products required[8].

Derivatives such as perfumes and insecticides are also ultimately obtained from crude oil. Naphtha, gasoil, LPG and ethane are used as the raw material or feedstock in many petrochemical processes. There are more than 4,000 different petrochemical products, but those which are considered as basic products include ethylene, propylene, butadiene, benzene, ammonia and methanol. The main groups of petrochemical end-products include plastics, synthetic fibres, synthetic rubbers, detergents, chemical fertilisers, solvents, paints, protective coatings and pharmaceuticals.

Less Coke Please

Transportation and industry are the largest consumers of crude oil, specifically light distillates. Heavier fuel oils and 'solid coke' are not as desirable as their lighter counterparts. Heavy oils such as bitumen and asphalt are often used in construction, road paving and in electrical power generation where they compete with coal. Heavier crudes or bottoms (residues) may be 'cracked' in order to form lighter crude. This, however, requires more capital investment and more energy to be expended in the refining process. Consequently, this reduces the value of heavier crude. Additionally, impurities such as heavy metals or sulphur will further reduce the value of the crude as it becomes more expensive to refine[9].

The crude blend, with its many different chemicals, must be separated and treated. This blend is distilled into 'fractions' using 'heat and height columns'. Temperatures can reach 350°C (662°F) in this process. This vaporises the hydrocarbons which subsequently rise to different 'heights' within a vertical column. The hydrocarbons cool down and become liquid again and are separated into fractions.



The solid residue remaining from the refinement of petroleum by the 'cracking' process is also a form of coke. Petroleum coke has many uses besides being a fuel, such as the manufacture of dry cells, electrodes, etc. Gas works that manufacture synthetic gas also produce coke as an end product called 'gas house coke'[10].

Fluid coking is a process by which heavy residual crude is converted into lighter products such as naphtha, kerosene, heating oil, and hydrocarbon gases. The 'fluid' term refers to the fact that coke particles are in a continuous system rather than in batches.

Clearly, a refinery's configuration will depend on the crude varietals it will process. In turn, this determines its configuration, processes and equipment. The list below gives an overview of standard refinery equipment:

• Desalter unit which washes out salt from the crude oil before it goes into the atmospheric distillation unit

• Atmospheric distiller or fractionating column

• Vacuum distiller which further distills the residual bottoms after atmospheric distillation

• Naphtha hydrotreater

• Alkylation equipment

• Catalytic reformer which contains a catalyst that is used to convert the naphtha-boiling range molecules into higher octane reformates (reformer products)

• Distillate hydrotreater unit which de-sulphurises distillate (diesel) after atmospheric distillation

• Fluid Catalytic Cracking (FCC) Unit which upgrades heavier fractions into lighter, more valuable products

• Hydrocracker unit which upgrades heavier fractions into lighter, more valuable products

• Coking unit which processes asphalt into gasoline and diesel fuel, leaving coke as a residual product

• Steam reforming unit which produces hydrogen for the hydrotreaters or hydrocracker

• Liquefied gas storage units

• Storage tanks for crude oil and finished products, and

• Utility units such as cooling towers for circulating cooling water, boiler plants for steam generation, and wastewater collection and treating systems.

Refining Efficiencies

Certain analysts and companies use 'product produced per barrel indices' and refining efficiencies as Key Performance Indicators (KPIs) of refineries. With so many variables, however, it is hard to make like-for-like comparisons. In addition, some companies may be acting as equity transfer advisors, and therefore, would have a vested interest in transacting a refining asset. Refining and marketing can offer margins; for example, in the US you can acquire stock in downstream companies (Enron was a bad example, but Premcor and Valero are good examples) that make healthy profits. This US fondness for investing in specialised parts of the oil and gas chain is catching on elsewhere. Several existing Russian and Eastern European refineries were groomed for private equity deals (and perhaps even Initial Purchase Offerings

There are more than 4,000 different petrochemical products, but those which are considered as basic products include ethylene, propylene, butadiene, benzene, ammonia and methanol.

[IPOs]) which shows the confidence some people now have in refining margins)[11].

Those profits, however, have not stacked up sufficiently to motivate investment in new refineries. Undoubtedly, one of the key contributors to heightened and more sensitive oil prices is the lack of refining capacity. Not a single new oil refinery has been built in the US since 1976 with existing plants working close to capacity. This is largely due to onerous government restrictions and permitting requirements as well as the aforementioned 'nimby' factor. As seen in 2005, hurricanes can shut down refineries causing prices to sky-rocket. As long as there is a continuing shortage of refining capacity, prices will continue to act this way. Refining is a continuous process, and should not be stopped once it has begun; however, even the most efficient plants must shut down for maintenance or for a product change periodically. By coincidence, if two or more refineries go offline at once for maintenance or a 'turnaround', it can cause a localised shortage that precipitates a price spike. Refineries try to mitigate periodic supply shortages by overproducing into storage facilities that can serve as a supply buffer during short offline periods (see *Chapter 12: Paper Barrels—Oil and Gas Markets*)[12].

Supply Side Discussion

Today's bottlenecks of minimal spare capacity are not caused by a peak in production or because of a lack of reserves; we have seen that there are plenty of opportunities (see *Chapter 2: Peak Oil and Medieval Maps*). The problem lies with refining capacity and inventories. We have noted that most current global refining capacity is geared toward sweet and light. That refining profile is not well suited to handling the increasing volumes of sour and heavy crude coming onto the market[13]. Building new refineries to handle sour and heavy crudes seems obvious enough given the characteristics of tough-to-produce reserves. So why aren't oil companies queuing up to build new refineries?

Part of the hesitancy is explained by the bull market from 2004 up to 2008 where the highest average utilisation was 86%. Surely, however, utilisation (and profitability) for new build refineries would be even higher given their up-to-date configuration for sour and heavy? Even though the answer is probably yes, the explanation for the reluctance in building new refineries lies with market uncertainties of future demand rather than profitability, social 'nimby' attitudes against refineries and the tendency for refineries to be built in large consuming countries.

If a refinery project begins today, it takes between five to seven years before it is operational. At that time, there is no idea of where the market will be. Industry does not look favourably on idle capacity and private companies are loathe to idling[14].

This is because shareholders want healthy returns yet refining margins are notoriously difficult to get right for

Variations in the strength and number of inter-molecular bonds, along with impurities, determine the viscosity and the melting and boiling points of most hydrocarbon compounds.

new builds, which do not make huge profits, and still there is the real risk of idling. Spare refining capacity, however, is precisely what the market needs to insulate it from knee-jerk reactions and maintain stable prices. That responsibility has fallen in the main part to Saudi Arabia, which has for years sought to provide a soft landing mechanism by maintaining excess production capacity, the so called supply cushion[15].

Ultimately, this is in the exporters' best interests because a prolonged period of depressed prices not only means a loss of windfall profits but giving oil away on the cheap. It can mean having the value of your most valuable resource mercilessly halved or cut even further. To illustrate, take Saudi Aramco, for example. Saudi Arabia's reserves are calculated at a high value of US $18.48 trillion at an oil price of US $70 (x 264 billion), US $13.20 trillion at an oil price US $50 and US $6.60 trillion at US $25. A sobering exercise, no doubt, but it is also worth mentioning that exporting countries are highly dependent on cashflow from oil revenues to keep their economies afloat[16].

That means NOCs must also keep a cash cushion when low prices swing back. Otherwise, exporters will simply have to pump higher volumes at lower prices to make up for lost revenues, if at all. That is a definite no-no in today's climate of resource sovereignty and maximising wealth.

A loss in short-term earnings and a wipe-out of the value of a finite set of reserves is not something exporters would be keen to see happen. That is why the Saudi Arabians are often called 'the voice of reason'. They want to keep markets and prices stable. They keep an eye on US inventories and check production forecasts accordingly. For exporters, an ideal rate of global economic growth is approximately one to two percent. In short, a stable scenario is one where economies grow at a manageable rate and sustain energy demand at moderate levels. Any shortfall in petroleum supply can be picked up by E & P technology gains, frontiers and growing renewables which are attractive at that price range. Lower prices and investment is pulled back.

This is a real uncertainty and much depends on how the industry will react in the next few years to say, 2011. Will it pull back investment as it appears is happening already? If so, this may simply delay the eventual supply side crunch due to a lack of new refining capacity. This could create a super spike in future oil prices. A concerted effort needs to be made to avoid this.

There is a 'paper' spanner in the works, however. We now need to consider what role the trading of paper barrels, such as oil futures, has on market volatility.

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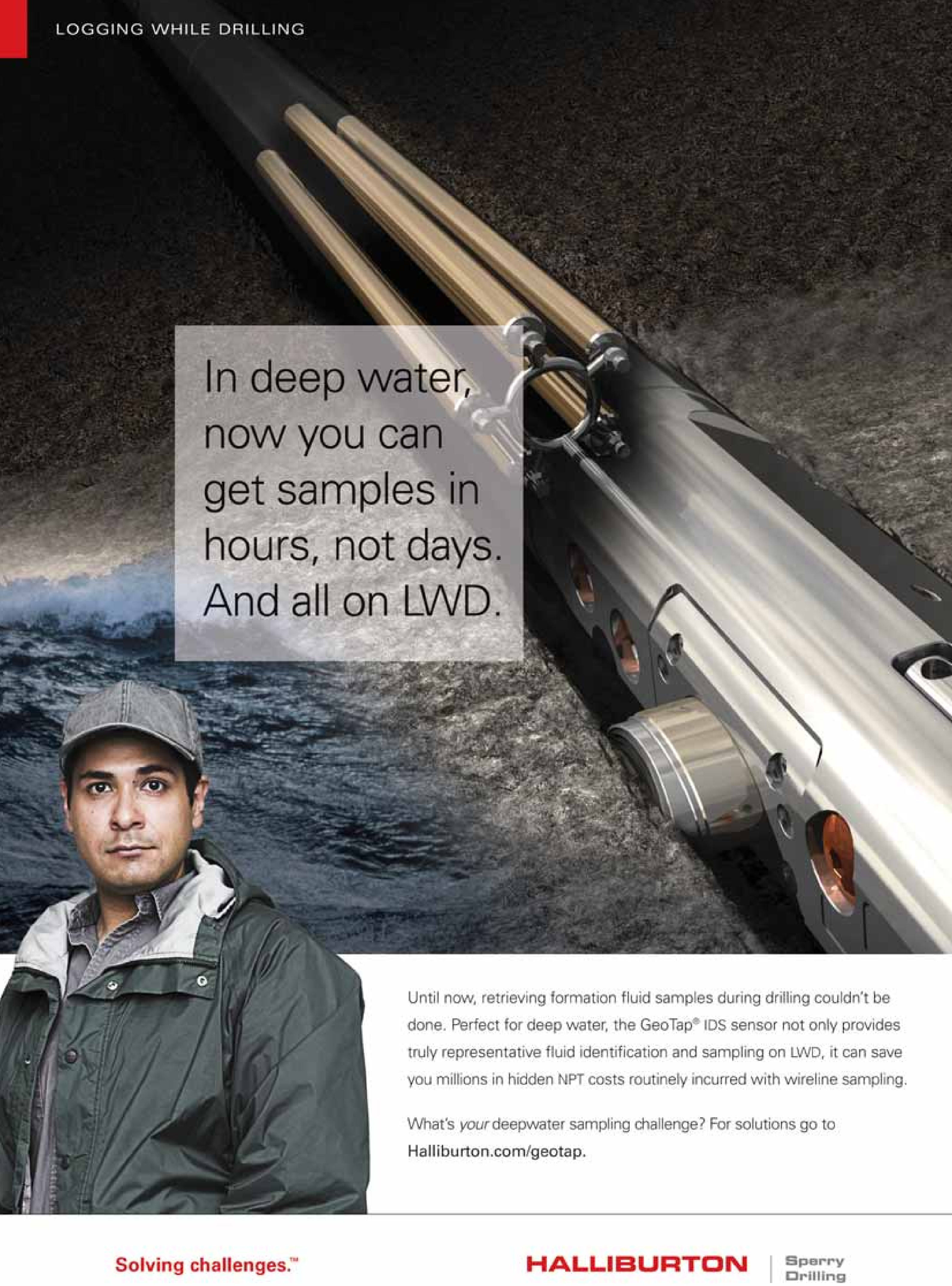
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