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The Innovative "Set-On" Geotextile Pipeline Weight (GPW)
BJ Blue Marlin starts operations in Campos Basin

BJ Blue Marlin, the third dynamic position DP-II stimulation vessel of the company's fleet operating in the country, brings technological innovations and represents a milestone in the Brazilian oil industry.

BJ Services delivered the BJ Blue Marlin vessel to Petrobras at the end of November 2008, a WSSV (Well Stimulation Support Vessel), entirely built in Brazil, which shall perform pumping, stimulation and sand control services for offshore oil and gas wells. The vessel was built in Navegantes (SC), at the Navship Shipyard, owned by the Chouest Group, under a partnership with BJ. The investment apportioned to the vessel was approximately US$ 70 million.

The vessel presentation ceremony was held in December in the city of Rio de Janeiro, with BJ’s COO and executive vice-president, David D. Dunlap, and the vice-president for Latin America and Sub-Saharan Africa, Gino Di Lullo present. The company has also celebrated 25 years of activity in the country.

Technology superiority
The elevated position achieved by BJ Blue Marlin is a consequence of the high degree of technological sophistication applied in its building. The control modules (software and hardware) of the stimulation plant made this vessel more versatile and reliable for the execution of processes involving stimulation and/or sand control operation. These advances allow BJ to offer more safety, agility and economy for its customers while executing the jobs proposed.

According to BJ Services do Brazil’s Country Manager, Douglas Marques, “Due to its huge versatility (capacity to perform a large variety of services required in Campos Basin) the vessel may execute operations at any place worldwide while other vessels, currently in operation outside Brazil, would hardly be adapted to the activities and needs of offshore operations in Campos Basin,” he explains.

The vessel is 85.3 meters of length, 17 meters of breadth (gauged from the most outboard point of the hull) and 6.4 meters of draft. The stimulation plant is 12,800HPP (hydraulic horse power) of installed power, pumping capacity for 50 barrels per minute (bpm), and storage capacity of up to 5,145 barrels (bbl) of fluid and more than 1,500,000 lbs of sustaining agent.

Optimization of field production
One of the vessel functions is to perform wells stimulation such as hydraulic fracturing and/or acidizing. This process comprises of operations or interventions in reservoirs as a way to create preferential paths, easing the fluid flow from the reservoir to the well. The purpose is to increase the oil field cost effectiveness either anticipating the production or increasing the field recovery factor. The vessel shall also execute pressurized pumping and sand control (Frac Pack and Gravel Pack). The activity of sand control is paramount to develop several fields in the basin, because a good portion of the reservoirs is sand-
stones of few or none consolidation, thus they require such control.

**An incentive for national content**

Unlike the preceding Blue Angel vessel, all stages of the process of building and assembling the BJ Blue Martin were carried out in the Brazilian territory, from the hull to the stimulation plant. Besides, a large portion of the labor employed was also from national origin.

Critical equipment such as high pressure pumps and automation software/hardware used at the stimulation plant had to be imported. It was also necessary to employ some technicians from its own matrix in Texas (USA) during the assembling.

“Usually stimulation vessels are built in other countries and brought to operate in here. So, this is a good opportunity for the country to export technology and experience with construction to other parts of the world”, said BJ’s COO and executive vice-president David D. Dunlap.

**Long term partnership**

With the knowledge and experience acquired along its 25 years of activity, BJ defends its position of being practically the sole company in Campos Basin to operate stimulation vessels. According to the vice-president for Latin America and Sub-Saharan Africa, Gino Di Lullo, in that trajectory, the company has learned both to identify the needs of the Basin and to meet the estate company’s requirements. “We have technology, technical expertise and competitive prices, besides a concerning degree as regards the use of national labor. We know what and how to operate to serve Petrobras,” he explained.

The Blue Marlin is the third BJ WSSV DP-II vessel operating for Petrobras. The other two, Blue Shark and Blue Angel, also operated in the Campos Basin for more than four years, respectively since 2002 and 2004. Currently, BJ Services meet 100% of the demand of WSSV offshore stimulation services from the estate company in Brazil. “We wish to walk together with Petrobras and for that we are directing investments to provide resources and services for the company,” said David

**Investments shall be maintained**

“I consider Brazil the safest investment.” With this statement BJ Services’ executive vice-president has confirmed the highlighted position of the country in the company’s next projects. The financial crisis that still scares investors and businessmen globally will not be a motive, at least up to the moment, to cut budget apportioned to Brazil. "The entire offshore segment of Brazil, particularly the Campos Basin, is one of the most important investments for BJ Services,” affirmed BJ’s executive vice-president.

As a service company, BJ remains aware of market oscillations and prepared in case of reduced customer activities. "Nowadays, Petrobras’ demands represent 95% of our activity in Brazil and according to its statements, there will not be shutdowns at least in the average term," said BJ Services do Brasil’s Contracts Manager Edemilson Souza. "Investments in projects already in course or prompt to start will hardly sustain any cuts," he added.

**In Search of new partnerships**

BJ is participating in other companies’ bids, some of those Brazilian, as well as working with international companies in Brazil, such as Chevron, ExxonMobil, Shell, Devon and Repsol. “We are seeking new partnerships to serve this market in full expansion," concluded Gino Di Lullo.
One Challenge after Another

Petrobras seeks technological solutions to produce oil and gas in an oil bearing province located in the presalt layer in wide stretches along the Brazilian coast.

Having discovered the oil-bearing province

Known as the pre-salt province, which extends for 800 kilometers along the Brazilian coastline, from the state of Espírito Santo to Santa Catarina and including the sedimentary basins of Espírito Santo, Campos, and Santos, Petrobras is facing important challenges. These include analyzing the multiple specifications of this new exploratory frontier, working to develop technological solutions to produce oil and gas in the location, and carrying out the necessary tests to choose the best alternatives, since there are presently no models to be followed. Logistical challenges regarding the new province, will require many innovations. The high seas support logistics, (that is the transportation of materials, equipment, and personnel and the installation of anchoring and well operation systems), will have to be specific to the project.

After all, in the case of the Tupi accumulation, and others in the province, the distance from the Brazilian coast is considerable: 300 km. In order to reach the oil reservoirs, more obstacles must be overcome, such as passing through a 2,000m water depth, a 1,000m layer of sediments and another 2,000m of salt.

This achieved, the recoverable oil and gas will be found in reservoirs needing greater drill penetration time than is required to penetrate the Campos Basin sandstone for example, and in the case of Tupi, at a distance of 5,000 to 7,000m below sea level,” informs José Formigli, executive manager of Pre-Salt Exploration.
Geological Challenges

The type of rock present in the reservoirs has no precedent in Petrobras activities. “Instead of turbidites, characteristic of the large accumulations in the post-salt layer and long known to the company, we are finding microbial carbonate, also known as microbialites, formations of a heterogeneous character practically without parameters in world history and the behavior of which in terms of oil recovery is still unknown to us. Therefore we cannot replicate models similar to those already used in other basins,” explains Jose Formigli.

Exploration Challenges

In the area of exploration, more challenges arise. When blocks situated in pre-salt were acquired by Petrobras and its partners in the Santos Basin, (for example, blocks BMS-8, 9, 10, and 11), as it was a practically unknown area of around 20,000 km², the company had to contract the largest 3D seismic marine survey carried out in the world to date. The seismic database obtained, of excellent quality, was fundamental to understand the geological context of the deepest sections of the basin and to interpret and map the principal geological horizons of the blocks. These studies culminated in the proposal of more reliable exploratory locations, which led to the discovery of hydrocarbons in the pre-salt province of the Santos Basin, and are being used for a better understanding of the type of reservoirs in other stretches of the province and for predicting the next exploratory locations.

Environmental Challenges

The high degree of carbon dioxide extracted together with oil, more than 20% in the case of some reservoirs, is another problem receiving Petrobras’ special attention. Formigli explains, ”When CO² combines with water, it forms a highly corrosive carbonic acid which requires the use of special steel alloys to prevent corrosion in the well casing, in underwater production equipment, like Wet Christmas Trees, and in components of the processing plant on the production platform”.

"In Tupi, for example, the proportion of natural gas is 220m³ for each cubic meter of oil, which is almost double the proportion found in the Campos Basin turbidites. The CO² contained in this natural gas requires an ecological destination so that it does not escape into the atmosphere, thereby contributing to an increase in the greenhouse gas effect. For this reason, the CO² is reinjected into the wells, which has the further advantage of reducing the viscosity of the remaining oil, making possible a greater potential recovery rate and, for this reason, ensuring a more lucrative operation for the company,” explains Formigli.

The formation of hydrates, substances resulting from the contact between gas and water, at low temperatures, which could result in the blocking of pipelines, must also be prevented. Strategies for prevention will include conserving oil temperatures taken from the reservoirs and possibly increasing the oil temperature in the pipelines by electric heating or by injecting inhibitors.
Planning Challenges

Careful planning is essential in order to prevent frustrating all the efforts involved. Included in this area is the acquisition of exploratory blocks backed by precise geological studies; the acquisition of seismic data, for the processing of which special logarithms were developed; and the meticulous evaluation and monitoring of data interpretation. Five evaluation plans covering the extension of the wells and the volumes therein were requested of the National Oil, Natural Gas and Biofuels Agency (ANP) in order to guide the Petrobras strategies more accurately, and to avoid precipitous decisions. The plans will have a duration of five years and will precede any declaration of the commercial viability of the reserves.

Tests of long duration, such as the one which began in Tupi in March 2009, and the following pilot phase when the forecast is to produce 100,000 barrels of oil equivalent and around 3.5 million cubic meters of natural gas per day starting in December 2010, were also carefully planned. The objective is to ensure that when the fields come onstream, there will be absolute knowledge of the variables involved.

Technological Challenges

In order to confront the technological challenges, Petrobras created the Pre-Salt Technological Program (PRO-SAL), implemented by the company’s research and development center, CENPES. "Within the scope of this program, 23 projects with the objective of searching for the most effective solutions in the areas of Well Engineering and Reserve and Flow Assurance Engineering are in progress," says the program coordinator, Cristiano Sombra. "The work is arduous. To give you an idea, it is sufficient to say that the salt has a plastic nature. As it is drilled, its tensions could cause the well to close and the drilling column to become trapped. When the drilling phase is finished and the well is completed, a steel casing is lowered into the well and the existing space between the casing and the drilled rock is filled with special cement. The salt could damage the steel. To prevent this from occurring, we are researching resistant materials.

However, we have to be careful to reach a balance, because, on the one hand, if the steel or the casing weighs too much, the drillship for placing this material may not succeed in doing the operation; on the other hand, as the oil drilling concession obtained could last for 27 years, and even be extended, the materials have to be durable," explains Sombra.

Economic Challenges

Bearing in mind that work on the new exploratory frontier will require billions of dollars, Petrobras will adopt a pioneering approach in dealing with such a large-scale undertaking. The company will have the cooperation of partners in developing the pre-salt province, although it will hold a majority stake in most of the blocks. Partners will include companies such as Amerada Hess, BG, Exxon, Partex, Petrogal-Galp, Repsol YPF Brasil, and Shell. The profitability of the undertaking is guaranteed for all. After all, as the executive manager of Petrobras Exploration, Mario Carminatti, states, “Oil has been discovered in all the wells drilled, which means 100% success up to now in this new exploratory frontier. In addition, in Tupi alone, it is estimated that the recoverable volume of oil and natural gas is between five and eight billion barrels.”

Overcoming the Challenges

Overcoming so many challenges pays off. After all, the oil discovered in the new province is light, 28° API, of excellent quality and high commercial value. In addition, the estimated volume of oil will compensate every effort made. Tupi, for example, has reserves ensuring that it will be considered as one of the largest discoveries in the world during the last seven years, which could transform Brazil into an oil exporting country. In this regard, each challenge arising is an additional stimulus to overcome the difficulties.
Discoveries Already Made

Some accumulations and oil fields have already been discovered in the pre-salt province. Up to the present, Tupi, because of the estimated recoverable volume of five to eight billion barrels of oil and natural gas, stands out as the flagship and may represent a 50% increase in the Brazilian proven reserves. Also identified are the accumulations called Guará, Bem-Tê-Vi, Júpiter, Caramba, and Iara. The expectation is that the discoveries made in the pre-salt layer in the Santos Basin will be more significant than those already discovered in the Campos and Espírito Santos basins. In both these basins, the salt layer shifted throughout the years, resulting in the oil rising to reservoirs located above the layer. In the Santos Basin, however, the salt layer remained practically intact, preserving the oil found there. The thickness of the salt layer in the Santos Basin exceeds 2,000m, while in the Campos Basin, for example, the thickness varies between 200 and 400m.

The First Oil

On 2 September 2008, the first oil in the pre-salt province was produced, taken from the Jubarte field in the Campos Basin. The oil was obtained from a well interconnected to platform P-34, the FPSO Juscelino Kubitschek, and was taken from a depth of 4,500m. The light, 28° API oil has a high commercial value. The extraction ceremony was attended by the President of Brazil, Luiz Inácio Lula da Silva, and representatives of the Petrobras Exploration and Production area. The maximum capacity foreseen for production in the Jubarte field in the test phase is 18,000 bpd. The long-term test should last from six months to a year, a period in which the performance of the oil will be evaluated, both in the reservoir and in the processing plant.
Three decades after the initiation of operations in the Campos Basin, Petrobras faces the challenge of producing extra-heavy oil in the Badejo field, thereby contributing to the creation of a new technological frontier in the world. The decisive test will be carried out by the FPSO Cidade de Rio das Ostras, which, in a pilot project, will process 12.8º API oil in the Siri Reservoir, eighty kilometers from the Brazilian coast.

In this undertaking, much more important than the volume of oil produced will be the progress of the pilot project, principally because the Siri Reservoir holds the heaviest and most viscous oil of all the Brazilian offshore fields and has all the conditions to serve as a field study for the acquisition of know-how in the production of extra-heavy oil. Offshore fields like Marlim Leste, Albacora Leste, Papa-Terra, Maromba, and Linguado, in addition to areas in the Brazilian Northeast, for example, will benefit from the know-how acquired. All around the world the interest is intense.

“The pilot project will generate important knowledge for the production of offshore extra-heavy oil, a challenge for everybody at present. This knowledge may help in the appropriation of as yet unproven reserves and in an increase of millions of barrels in proven reserves,” says Guilherme
Petrobras is going to produce extra-heavy oil in the Siri Reservoir and thus obtain knowledge unprecedented in the world in this area

Estrella, the Petrobras director of Exploration and Production. For these reasons, the Badejo Field experiment is being watched with maximum attention.

“The whole world is watching Siri. After all, we estimate that the pilot project may result in the addition of up to 238 million barrels to Petrobras’ proven reserves,” says André Moço, the project’s general coordinator. From the initial outflow to the offloading of the oil, original information will be obtained thanks to this project. The technological challenges involved are also formidable. These include the construction of a well with a two-kilometer horizontal stretch; the installation of a high yield underwater centrifugal pump (BCSS), which will ensure a high flow rate for the oil produced; separation of the water and gas produced; and the processing of the extra-heavy oil, which will require an extremely high operating temperature (140º). At least 2.5 million barrels of liquid must be produced to validate the project. Once the projected actions planned for the Siri Reservoir have been implemented, estimated to take about two years and to cost around US$ 1.78 million, and when all Petrobras’ expectations have been realized with regard to the project, the company will have made a significant contribution to the offshore community in relation to heavy oil. Then it will be able to start development of production in the Siri Reservoir. A production platform, with daily capacity of 100,000 barrels, will be a major factor in the realization of this accomplishment.

The Siri Reservoir

The Siri Reservoir was discovered in the 1970s, at the top of the Badejo field, in shallow waters about 95 meters deep, extending for between 700 to 900 meters below the seabed and covering about 26km² in the southern part of the Campos Basin. At that time, the price of oil did not justify the high investment required for the production of extra-heavy oil and the drillships crossed Siri seeking the depths of the Badejo field. There, operations started in 1981 and production peaked (12,000 barrels a day) in 1984, after which production declined until Petrobras’ Mature Fields Recovery Enhancement Program (RECAGE) was implemented. Once new technologies such as the drilling of horizontal wells have been developed; once the productivity of the reservoir has been proven; and once the economic viability has been confirmed, Petrobras will turn its attention to the Siri Reservoir and will prepare to implement the pilot project, which will provide the world with important knowledge regarding the production of extra-heavy oils. The oil from Siri will be transported to Petrobras’ Reduc and Replan refineries, where it will be blended with other oils.
An Interview with HRT

Established in 2005, HRT Petroleum is a service company that has created an admirable reputation for resolving many of the difficulties associated with petroleum exploration. President Marcio Mello and Vice President Nilo Azambuja are dedicated to finding effective solutions via a multi-disciplinary approach. Together with a highly experienced and focused team, they use the latest technologies and applications to locate new hydrocarbon deposits.

HRT’s ethos could well be summed up by their belief that Petroleum Exploration requires a multidisciplinary approach, much the same as any major city’s CSI (crime scene investigation) unit. Just as an important crime can be solved by multidisciplinary approach, like finding a single drop of blood or DNA from a single strand of hair, the team at HRT know that a small detail in an oil sample can solve the most challenging problem, such as discovering a giant new oil and gas prospect!!

Nilo Azambuja explains, “The need to integrate all the data available requires experts to delve deep into each technology and it requires a free exchange of ideas. Experienced geoscientists are essential for the analyses to bring the most correct results.”

“Oil companies face demanding challenges in locating new hydrocarbon deposits, with many frontier areas presenting both considerable risks and very high costs.

"HRT Petroleum has 3 strong points, which gives us the edge, especially in terms of competing effectively and delivering efficiently. We have built a knowledge-based company, and this is where our main strength lies, supported by our excellent geoscientists many of who have more than 30 years experience. Furthermore, by using state-of-the-art equipment we gain fast, accurate analyses. Finally, we can help reduce exploration risks by fully integrating the skills required to complete detailed basin modelling and environmental assessment including geochemistry, biostratigraphy, seismic interpretation, structural geology, biology, oceanography, environmental licensing and monitoring.”It is Nilo who manages the

highly experienced team of geoscientists. Prior to his current role he was head of the Basin Modelling Group at the Petrobras Research Centre. Naturally he is well qualified to direct and lead the HRT G & G teams.

While at Petrobras, Marcio Mello and Nilo Azambuja both received the education and experience that would stand them in good stead for the future. During the 1970s there were positive developments for geoscientists and they both benefited immensely from Petrobras’ innovative approach to training its geoscientists. A hands-on approach allowed Marcio to further his education and gain unique field experiences across the globe. By following Petrobras’ philosophy of reciprocating talent and giving back, Marcio helped train geologists in Pe-mex, PDVSA and Ecopetrol as well as in USA and even war torn Angola for 3 years where his commitment persevered through curfews and an ever-present threat of violence.

Testament to Marcio’s creativity and dedication is the fact that he helped form the most comprehensive laboratory and petroleum geochemistry group in Latin America, the Petrobras - CEGEQ (Centre of Excellence in Geochemistry). Under his direction over 120 experts began to apply the petroleum system approach to sedimentary basins in Latin America and Africa. Support from this unit also went on to many Latin American Oil companies for oil and gas exploration as well as environmental issues.

Marcio says, “The experience at Petrobras helped me build a knowledge base about active petroleum systems present in the Southern Hemisphere and serves as a solid foundation for starting my new ventures.” This invaluable experience and knowledge together with his unique spirit of adventure provided the motivation to start a new company. Marcio reflects on his earlier life as a big fisherman and diver around the Rivers of the Amazon Jungle. It is his belief that this helped give him the experience of adventure without being afraid of risks. His early career at Petrobras saw him serve as a surface geologist first Onshore at Reconcavo Basin and later on oil rigs in areas including the famous Campos Basin. He recalls the tough decisions and hard choices he faced. He learned to take those important decisions in the blink of an eye.
Marcio Mello, President of HRT Petroleum

and is grateful for the wisdom and fortune that placed him in the right places to make the right decisions at the right time.

More recently, Dr. Marcio Mello has followed on from founding a pioneering Center of Excellence in Geochemistry at Petrobras by establishing several of his own companies. In just 4 years they have fast become the most complete group of petroleum and environmental laboratories in Latin America.

Marcio says, “During 2004 I sold interests in all the companies. Then I hit the road running! It took just 4 days, not years, to start a new oil and gas exploration and environmental services company called High Resolution Technology & Petroleum. My aim was to create the best petroleum system, expert consultant, petroleum laboratory and Service Company in the South Atlantic Realm.”

Upon visiting HRT’s modern office building overlooking Copacabana beach and his state of the art laboratory in Botafogo you begin to learn that Marcio has succeeded with his aims. You enter the office and the Lab with CSI brought to mind again as you remove your outdoor shoes and place your feet into special slippers. Geologists, geophysicists, chemists, engineers and geochemists work side by side on white carpet overlooking the beach and the Christ Mountain. There is a clinical environment but it is also high-tech with computer screens, mass spectrometers and gas-chromatography displaying geochemical sampling, seismic and well data. There is a focus on integration, placing the expertise together with the required data.

Situated very close to the laboratory is Marcio’s literally sparkling office, decorated with the finest Brazilian amethyst geodes and quartz crystals. Those who are familiar with Dr. Mello’s talks and presentations know that he is concise and direct. However, he has a natural way of bringing his presentations to life, and maintaining your interest and attention in an enjoyable manner. A dynamic personality complements his strong business manner. It is no wonder that he strives to deliver more than his competitors and often goes the extra mile to ensure the highest standards are always maintained.

Marcio and Nilo are both very patriotic and very keen to see Brazil reach its full potential. To help with this endeavour HRT is developing new geochemical technologies that are applicable to an increasing number of explored and frontier areas in Latin America and Africa.

Nilo elaborates, “We’re aiming to make information more accessible to our clients so that they can benefit from quick access on their laptops to our data, wells and seismic wherever they are located. However, this is just a small part of our operations because after the data is assembled, the real detective work starts! To be creative, you need a lot of data and experience to build the basin models. Once a model is built we return to the data to identify what opportunities lay ahead. We can then suggest ideas on where reservoirs can be filled, which may be the best blocks to bid on and drill.”

Recently, HRT, in cooperation with CGGVeritas, finished a very important study over Brazil’s pre-salt giant oil province: the 3D Petroleum Systems Modelling of the Deep Water Santos area, covering the BM-S-8, BM-S-9, BM-S-10 and BM-S-11 Cluster Blocks and surroundings. This area encompasses the five most important, recent worldwide discoveries including the supergiant fields of Tupi and Iara and the successfully tested prospects of Bem-te-Vi, Guará, Carioca and Parati. Volumes are surprisingly large; perhaps reaching 18 Bbbls of reserves. The study includes a very detailed petroleum system 3D model, in which oil and gas generation, expulsion and migration pathways are showed in detail as well as the impressive prediction of hydrocarbon volumes and composition of the oil and gas accumulations.

Marcio summarises, “The integrated approach is the best way to reduce exploration risk, not only in frontier areas but to resuscitate mature basins. We live by our motto, No More Dry Wells”. 🌟

Nilo Azambuja, Vice-President of HRT Petroleum
A Boost for Development

Platforms P-51 and P-53 contribute to the revitalization of the Brazilian shipbuilding industry and to the creation of jobs and income in Brazil, ensuring increased oil and gas production and development in the nation.

Two Petrobras platforms

The FPSO P-53 and the semi-submersible unit P-51, constructed in Brazil and scheduled to go into operation in late 2008 and early 2009 respectively, have had a significant impact on the country prior to the start of production and are of great promise for the coming years. They have contributed to the revitalization of the national shipbuilding industry and to the creation of domestic employment and income, given that more than 70% of the goods and services were acquired from Brazilian suppliers. In addition, the platforms will reinforce the country’s self-sufficiency in oil, as they will contribute an extra daily production of 360,000 barrels of oil and gas.

P-53

Resulting from the conversion of the Portuguese vessel Setebello, the FPSO-53, constructed in Brazil, constitutes an important element of the Brazilian government’s Plano de Aceleração do Crescimento- PAC (Growth Acceleration Plan) and has provided an important boost to the Brazilian shipbuilding industry. After all, as the Petrobras director of Exploration and Production, Guilherme Estrella, emphasizes, the project has generated around 4,500 direct and 15,000 indirect jobs.

In the energy field, the contribution is also considerable. “The FPSO has a production capacity of 180,000 barrels of 20º API oil per day, compresses six million m³ of gas and generates 92 MW of electric energy. Regarding water injection capacity, the unit’s capacity totals 245,000 barrels daily,” says José Antonio Figueiredo, the Petrobras South-Southeast Exploration and Production division executive manager.

The FPSO was installed in the Marlim Leste field in the Campos Basin, 120 km from the coast, and is anchored at a depth of 1,080 meters, becoming the first production unit in that field. There, it is interconnected to 21 wells, of which 13 are oil and gas producers and eight, water injectors.

Equipped with a 26 cm diameter turret system, that is, a receiving tower for flexible production and injection lines, oil pipelines, gas pipelines, and anchorage lines, it also has the capacity to receive 75 flexible lines.

Oil production is transported to land by means of an autonomous re-pumping platform, the PRA-1. Part of the daily gas production is used for the unit’s internal consumption, as a fuel for the generation of electric energy. The rest is transferred to platform P-26, to be incorporated into the Campos Basin gas network.

The President of Brazil (center) attends the launch of the FPSO P-53
P-51

Destined to operate in the Marlim Sul field in the Campos Basin (RJ), 150 km from the coast in a stretch of water 1,255 meters deep, P-51 is the first semi-submersible platform constructed entirely in Brazil. It is also another result of the policy implemented by the Brazilian government and Petrobras to revitalize the national shipbuilding industry.

In this regard, the unit was a key component in the Plan for Accelerated Growth currently in force in Brazil. “The work on this project alone created 4,000 direct and 12,000 indirect jobs, which helped strengthen the growth of Brazilian industry and the consolidation of the national content policy in Brazil,” explains Guilherme Estrella, the Petrobras director of Exploration and Production.

Included in the Campos Basin Drainage and Treatment Director Plan (PDET) and in the Plan to Anticipate Natural Gas Production (Plangas), P-51 will also contribute to increasing the supply of gas in the Brazilian market.

The platform will have a production capacity of 180,000 barrels of 22º API oil per day, a gas compression capacity of six million cubic meters, a water injection capacity of 282,000 bpd, and a generation capacity of 100 MW of electric energy daily, a total sufficient to supply a city of 300,000 inhabitants. In addition, it will be interconnected with 19 wells, of which 10 will be producers of oil and gas and 9 water injectors, and will be responsible for about 8% of the total volume of oil produced in Brazil, once the production peak is reached, foreseen for 2010.

Considering the contribution which P-53 and P-51 platforms have made to the revitalization of the Brazilian shipbuilding industry and the important role reserved for both in the strengthening of Brazil’s self-sufficiency in oil, Petrobras and Brazil have won important victories, as well as greater facility in developing risk ventures in the future.
The Cognitus II Project

Petrobras and its partners develop cognitive tools for environmental management in Amazonia.

Aware that operating in Amazonia, in the Urucu petroleum province, in the Isaac Sabbá Refinery, and in the Solimões Terminal requires all possible care to guarantee successful operations and to preserve the environment, Petrobras, together with its partners, is implementing the Cognitus II Project.

The objectives are to develop cognitive tools, with the help of cutting-edge technology, for managing the environment in the region, for perfecting environmental sensitivity charts, and for defining the ecosystems to be protected in the event of an oil spill. “Derived from a project by the artist Wagner Garcia and fine-tuned in partnership with Petrobras, the Cognitus Project – The Application of Cognitive Tools for Environmental Management in Amazonia, now in phase II, proposes new theories and intellectual tools to measure and interpret the quality and complexity of the natural phenomena found in the Amazon region.

After all, traditional scientific methodology did not provide the degree of resolution necessary for the understanding of, for example, the seasonal variations in the complex Amazonian ecosystems and the hydrological scenarios of drought, rising waters, flooding, and receding waters. Historical environmental data regarding the region were also scarce.

Therefore, the decision was made to invest in cutting-edge research such as robotics and nanotechnology to satisfy the existing needs and to analyze Amazonia on scales varying from the microscopic to information obtained from satellites,” explains the Petrobras geologist and general coordinator of Cognitus II, Fernando Pellon de Miranda.

The Cognitus II Project is being carried out in partnership with the Centro de Pesquisas Renato Archer (Renato Archer Research Center) in the state of São Paulo, The Instituto Nacional de Pesquisas da Amazonia (Amazonia National Research Center) in the
In addition, there is an interface with the PIATAM Project (Potential Environmental Impacts and Risks of the Oil and Gas Industry in Amazonas), co-managed and mainly financed by Petrobras. There are three lines of research in the project: AmazonBOTS, Nanobiotechnology, and Hypersigns.

The research line known as AmazonBOTS deals with the development of robotic systems for the active monitoring of Amazonian lakes, which are often inaccessible to man. Besides, it facilitates the compilation of series of historic data gathered in real time, including details on the dispersion of oil in lowland flat areas with flooded vegetation and the direction and the intensity of the flow of water. The research line also includes robots projected to monitor the microbiotics of the region.

“We are looking at a series of fixed, autonomous Kwata robots for environmental monitoring, such as the Kwata Eros, which will monitor the vulnerability to erosion in the region of the Coari-Manaus gas pipeline and the Urucu oil province, deep in the Amazon forest; the mobile, autonomous robot Porake, equipped with an electrical localization system similar to that of electric fish, excellent for use in cloudy...
waters where optical systems are ineffective and which will monitor the waters of the Solimões and Negro rivers; the Biobots robot, still in development, whose design is inspired by the biological evolution of animal species in general, and which can change shape in order to surmount obstacles; and the Hybrid Environmental Robot, a mobile robotic vehicle for field work,” explains Pellon.

“The Hybrid Environmental Robot, named after Chico Mendes, in honor of the Brazilian environmentalist who lived and worked in Amazonia defending the sustainable use of its natural resources, can operate with a crew or by remote control, in the water, on land, in the marshes, in flooded regions, and over the Amazon aquatic vegetation.

Powered by electric batteries and alternative energy sources, it is equipped with two electronic arms for collecting material in the water and in the forest and is able to carry two TV cameras which record images and transmit them to a base. In emergencies, it can

Cognitus II makes possible the measurement and the interpretation of the seasonal variations of the Amazonian ecosystems

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transmit data in real time directly from the forest, 24 hours a day. It also has the advantage of being neither polluting nor invasive, as it does not destroy the vegetation and it is silent.

The equipment is unprecedented in the world. The most similar robots are the ones used in space, which travel over much less complex surfaces,” says Pellon. The research line known as Nanobiotechnology deals with the construction of microscopic sensors and chips designed to collect series of historic data in the Amazon region.

These data will serve as support in the analysis of fresh water and the creatures living therein discovered by the robots of the AmazonBOTS research line. They will also characterize indicators and detect chemical compositions foreign to the organisms of these creatures or found to be at levels higher than normal, conditions which might be connected to pollution caused by oil spills.

“This line of research includes some sub-projects. One of them, for example, the Metagenoma, researches the development of methodologies for carrying out taxonomic, genetic, and functional analyses of microbionic flora. Another sub-project, called Clothing Earth with Mind, deals with the observation of the interaction on a nanoscale, that is of one millionth of a millimeter, between proteins of any organic composition in microbionic processes.

The objective is to validate sensors on a micro scale, of one thousandth of a millimeter, for this observation, which may indicate, for example, the action of specific biogeochemical processes of the floodplain of the Solimões river. Still another sub-project, known as Liquid Computation, covers the development of an unconventional computational model, inspired by molecular biological processes, for the optimized analysis of data provided by the Metagenoma and Clothing Earth with Mind sub-projects,” explains Pellon. As for the Hypersign line of research, it includes the development of semi-optic instruments and technologies that will make possible the application of the series of environmental data used in the seasonal variations of water levels in the hydrographic sub-basins located in the Urucu-Manaus stretch in Amazonia.

The work of Cognitus II has produced results. The versatility of the Hybrid Environmental Robot, for example, drew the attention of the riverside dwellers, who proposed that it could also be used as an ambulance and as a means for transporting food and the local population.

After all, in the ebb season, large extents of land remain soaked in the Amazon region and mud hampers the passage of personnel and vessels for many days. Ney Robinson, the engineer in charge of the robot project, is already engaged in making possible the social use of the vehicle, as well as its mass production.

In addition, today more facilities are available to obtain information on Amazonia than were available in any past period. Thanks to the Cognitus II Project, cutting-edge technology is definitively at the service of the region, its specific characteristics, Petrobras’ sustainable activities, and, consequently, the progress of science. ✨
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ENVIRONMENTAL EVALUATION
Reducing Uncertainty and Cost
Innovative Underreamer Verifies


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Applications such as close tolerance casing design and expandable liners, often necessary for deepwater and subsalt well construction, require underreaming to ensure adequate reservoir diameters. However, underreaming generates uncertainty sometimes, particularly in hard formations. Instead of direct real-time verification, reliance is placed on indirect indicators such as increased standpipe pressure or drilling torque. The uncertainty as to whether the desired wellbore-diameter is actually delivered exists until a calliper is run. Subsequently, a correction run may still be needed, hence additional cost.

This paper explains a design process to solve these problems. An explanation of a novel technology illustrates how it verifies and detects variations in underreaming diameter in real-time. A telemetry system alerts the user if there is a significant difference between planned and actual diameters and prompts a check of operational parameters such as WOB, drilling fluid pump rates or RPM, if needed, repeat underreaming in the uncertain interval.

A comparative evaluation was made of the drilling dynamics of underreamers and the root cause analysis of NPT. For example, bit only RoPs are higher than underreaming RoPs and in a combination BHA the bit tends to outdrill the underreamer. Not only does the underreaming have limited cutter contact with the wellbore and limited hydraulics, BHA modelling shows these limitations are worsened by wall-side forces and bending moments which are concentrated at the underreamer.

The design process sought to improve traditional technology by considering RoP, improved underreaming BHA stability and generate a more balanced cutting action. CFD (Computational fluid dynamics) show how a novel configuration of nozzle distances and orientations improves cuttings evacuation and reduces particle residence times.

In conclusion, a drilling engineering risk table presents underreaming applications and is used as a benchmark for a comparative evaluation of underreaming risk types.

Introduction

Oil and gas companies are exploring and developing reserves in more challenging basins such as those in water depths exceeding 6,000 ft (1,830m) or below massive salt sections. These wells have highly complex directional trajectories with casing designs including 6 or more well sections. Known as ‘designer’ or ‘close tolerance casing’ wells, such wells have narrow casing diameters with tight tolerances and have created a need to enlarge the wellbore to avoid very small diameter reservoir sections and lower production rates (Figure 1 PPFG). In other applications such as cemented solid expandable liners, underreamers are required to provide the tolerance for tubular expansion to occur or for increased cement sheath. The tolerances between the enlarged wellbore and the expanded tubular are very close.

Therefore, the bottom-hole assemblies that are needed to drill or complete these wells routinely include devices to underream the well-bore. In this way, underreamed hole size has become an integral part of well construction and there is now an increased dependence on underreaming to meet planned wellbore diameters across the industry Ref 2.

Underreamer

An underreamer is used to enlarge a borehole beyond its original or pilot bit size or existing hole size Ref 3. Enlargement is typically done below a restriction in the borehole (usually pre-existing casing), and the drilling diameter of an underreamer is always greater than that of the pass-through diameter of the restriction (or casing). Additionally, an underreamer is provided with activation and deactivation modes and mechanisms for extending and retracting cutting elements to ensure effective underreaming once it has passed below the restriction. Consequently, underreaming is taken to mean ‘the opening of a well-bore after passing through a restriction’
and covers terms such as:

1. Underreaming/Bidirectional Underreaming
2. Hole enlargement
3. Underreaming while drilling/ back reaming
4. Simultaneous underreaming
5. Drilling with a bicentre/eccentric bit
6. Hole-opening

**Underreaming in Well Construction**

The list below shows a breakdown of possible well construction underreaming applications. These applications are summarised as follows:

1. Contingency Casing (Shallow Hazards)
2. Close Tolerance Casing (Narrow PPFG)
3. Cemented Expandable Liners
4. Monobore
5. Gravel Packs
6. Sand Screens
7. Casing Drilling with Retrievable System
8. Remedial Work
9. Ream Sidetracks/Ease Tripping
10. BOP/Well Restrictions Ref4
11. Improve Cementing Tolerances
12. Drill Through Completions
13. Scale/Wax Removal Ref5
14. Hole Cleaning/ECD Improvements
15. Increased Production
16. Improve Wiper Trip
17. Remove Heavy Mud Skin
18. Remove Formation Damage Ref6
19. Remove Excess Cement
20. Overcome Formation Creep Ref7
21. Reduce Stringers
22. Drill-in Liners

*Figure 1 Shows Underreaming Applications Across The Industry*
Time-Lag Between Underreaming and Measurement

Traditionally, underreaming and measurement have been considered as two separate and distinct operations. An underreaming run could take 24 hours, after which a further 24 hours could be required for preparation of the calliper run. A further 24 hours could be expended in the calliper run before knowledge could be gained of actual wellbore diameters. The time-lag between underreaming and calliper measurements, therefore could easily exceed 48 hours depending on the depths involved. If the actual hole diameter did not match the planned diameter, casing tolerances would not be met and therefore a correction run would be required and the whole cycle of underreaming and calliper measurements would need to be repeated.

Measurement methods

Drilling measurements may involve the acquisition and communication to surface of various types of wellbore and formation evaluation data such as resistivity, porosity, permeability, azimuth, inclination, borehole diameter or rugosity, formation dips, bedding angles, pressure and temperature. Measurement itself occurs in two modes, either wireline or logging-while-drilling.

Wireline and Calliper Log

Wireline logging is a common measurement technique and is performed as a separate and consecutive activity to drilling involving the conveyance of measurement tools on a wireline or drillpipe if hole is highly deviated or horizontal. Wireline callipers use a plurality of fingers to take borehole diameter measurements. However, wireline callipers can only take measurements in an axial direction and are not robust enough for drilling applications.

Such calliper designs are based on mechanical mechanisms i.e. pivot points or moving knuckles which are known to break or malfunction due to high bending moments or drilling fluid packing out between moving parts and causing an inability to function or an inability to retrieve the bottom-hole assembly. It is precisely due to these reasons that the design of underreamers and underreamer blocks themselves evolved from cutter arms toward solid block designs Ref 8, 9.

LWD Callipers

Logging-while-drilling tools may acquire various data from the wellbore. Acoustic callipers may be incorporated with logging tools Ref 10. As they can be rotated, acoustic callipers may be used while drilling to acquire measurement data. However, not all logging tools are reconfigured with acoustic callipers due to the needs of the complex LWD system itself and formation evaluation requirements. Acoustic callipers may also suffer from ultrasound signal attenuation due to changes in the density of drilling mud as well as rotational limitations occurring in slide drilling, where a downhole motor rotates the bit. In rotary steerable applications, the wall contact requirements of the steerable system will dictate the RSS be placed below the LWD in order to apply the requisite wall side-forces to the bit to control azimuth and inclination. In cases where the location of any acoustic calliper is below the underreamer, the acoustic calliper only provides indication of pilot hole size, not the underreamed hole.

It is routine for certain oil companies to take borehole measurements as a separate activity after drilling or underreaming (wellbore enlargement) has taken place. The time-lag associated with the separated operations of enlargement and measurement leads to uncertainty and unnecessary cost.

Operational Uncertainty

Traditional technology may not provide reliable information as it contains uncertainty due to the dependence on extended cutter positions or hydraulic drilling practices as an indicative assumption that the planned underreamed hole is actually being delivered. There are no actual real-time measurements whether direct or inferred.

Indirect Indicators and Inferences

It is usual practice to depend on indirect indicators such as whether cutter blocks are open or closed or whether fluid pathways are open and a pressure spike is seen at the rig floor to indicate activation. It is known that reliance is placed on rudimentary and time-consuming indicators of verification such as an increase in drilling torque as cutters interact with the formation or pulling up the BHA to the previous hole size in order to see whether the top-drive stalls as the bottom-hole assembly gets hanged up due to the expanded underreamer. Such indicators do not provide actual measurements of the underreamed wellbore; they simply give information on the mechanical or hydraulic status of an aspect of the tool which may or may not lead to the desired well diameter. It is this fundamental uncertainty that may lead to NPT Ref 3.

New Solution

The new technology provides a step-change in drilling efficiency as compared with traditional methods. This is because the actual diameter of the underreamed hole is
measured directly behind the underreamer cutter blocks in real-time. This provides for real time performance verification and automated troubleshooting. The new technology eliminates the need for a separate calliper run and minimizes the need for corrective underreaming runs. If the wellbore is found to be undergauge, the technology automatically detects and diagnoses the faults, which may help to repeat underreaming until a satisfactory result is achieved in real-time.

**Design Process**

There are more than 21 underreaming applications and many operators that underream, but the skill is focusing on where the synergy and value of hole measurement and underreamer is greatest. Underreaming applications and the usage of underreamers is not straightforward. The usage is related to differences in operator culture, perception of risks, product preferences and application complexity. Different oil companies can have very distinct approaches to the drilling or production issues encountered, and related potential underreaming applications. The design process took these factors into consideration. (See Figure 1)

To minimise or eliminate risks associated with traditional technology the design process incorporated several computerized and manual analytical tools. These were:

1. FEA (Finite Element Analysis),
2. Residual Stress Engineering,
3. BHA modelling,
4. CFD (Computational Fluid Dynamics)
5. NPT of underreaming well construction operations.

**FEA (Finite Element Analysis)**

The analysis represents the tool by a finite number of elements which are identified by a computer program. The elements are then modelled according to differing levels of stress, loading and erosion. This provides an idea of where design refinements need to be made. The FEA also helps identify residual stresses that may be induced during manufacture i.e. heat induced forging, welding body, tungsten carbide insert brazing. It also helps the design of PDC cutters and cutter blocks. The loading inputs were taken from a variety of loading scenarios such as geomechanical formation hardness, directional and stabilizer positioning for BHA moments and well bore inclination i.e. horizontal and directional wells.

**Residual Stress Engineering**

This optimises tool life and prevents premature failures by considering such stresses. Residual stresses remain after the original source of stress has been removed. Sources vary from heat based i.e. forging, brazing, welding to mechanical i.e. inelastic loads. If the stresses go unchecked they may adversely affect the performance of the component leading to premature failure (stuckfish or in the worst cases a sidetrack). Heat from forging or welding may cause local expansion, which is taken up during welding by either the molten metal or the parts being welded. The cooling process is not uniform and certain areas contract faster than others, leaving residual stresses.

**BHA Modelling**

From a directional drilling perspective, the underreamer must also stabilise the BHA as a string or nearbit stabiliser. Consequently, in certain BHA placements it will help generate required directional turns as one of three known wellbore contact points. Here it will have to overcome wall-side-forces and bending-moments to provide directional control possibilities and act to minimize axial, lateral and torsional oscillation and vibration generated.

![Figure 2 shows Typical Bending Moments Concentrated at the Underreamer. Note the Underreamer is nearly 40 m behind the bit.](image1)

![Figure 3 shows Typical Drillstring, BHA Deflection within the Underreamed Section.](image2)
by the BHA or drillstring. Even where configured behind a bullnose the underreamer must still perform part of these functions. These forces were modelled on the underreamer. (See Figures 2 and 3)

**CFD (Computational Fluid Dynamics)**

This warns of potential areas for particle based fluid erosion and different flow regimes. Laminar flow is modelled within the tools’ ID and internal components that are open to flow. Turbulent flow is modelled outside of the tool and all external faces. This improves the design from a QA/QC perspective. The flow simulation has been used to optimise both the bit and underreamer hydraulics. The model creates flow paths inside the tool and near the wellbore between the bit, BHA and the underreamer. Drilling mud, cuttings and flow path areas are simulated as turbulent flow passes through and around these elements. Tracking times identify the path taken by formation particles generated by each cutter. The objective is to achieve an optimal flow balance between the bit, the total volume of cuttings generated by the bit, the volume of cuttings generated by the underreamer and the specific volume of cuttings generated by each cutter.

The design for the junk slot area can also be optimised so that flow volume for a specific junk slot is optimised.

**NPT Root Causes**

Our overall goal was to improve drilling efficiency by identifying root causes of NPT (Non Productive Time). Subsequently, a distinction was made between avoidable and recurrent causes of downtime or NPT and isolated or unavoidable NPT events. (See Figure 4) In order to do this, representative data related to underreaming across the industry deepwater, sub-salt and onshore assets was analysed. However this was not a simple task for several reasons.

First, it is often noted that there are ‘no failures’, nor ‘NPT’, especially at first sight. For example, a typical response is there is no underreaming NPT without looking at the broader data.

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**Figure 4 Shows A Typical Well Performance Plot of Days v Depth**
Second, failures are not always reported at the time and the root cause of failures can only be ascertained after detailed inspection reports have been completed. This may take several months after the problem occurs. Oil company personnel may have moved onto another well by then. Thirdly, failures and NPT are highly sensitive issues, not least due to their commercial and liability implications. However, by analysing industry end-of-well reports and wellbore data it was possible to identify factual NPT and identify non-confidential MTBF (Mean Time Between Failure). The data included:

1. Total underreamed footage per year,
2. Total Drilling NPT types, BHA failure events,
3. Underreaming NPT
4. MTBF for specific underreaming type

The point of the exercise was to identify underreaming design and operational improvements to be used within the overall well engineering and BHA design process.

Significant causes of NPT were highlighted as:
1. Inability to activate or maintain tool active
2. Cutter Block or Component Loss
3. Excessive Vibration
4. Loss of Directional Control
5. Excess Overpull
6. Unplanned Activation
7. Unable to underream hard formation
8. Stuck closed
9. Stuck open
10. Poor hole cleaning or balling
11. Unable to backream
12. Exceeding circulating life
13. Unable to updrill
14. No fishing ID

**Reducing NPT**

The primary cause of NPT associated with underreaming was reported as the ‘Inability to activate or maintain tool active’. Essentially this was a typical scenario: ‘drilling ahead’ based on mechanical indication i.e. ‘surface indication, SPP peaks, increase in drilling torque and/or increase of overpull. This raises the question, if mechanical indicators alone were sufficient to definitively know the status of the tool why would ‘failure to activate’ rank as the primary failure event? In several cases it was not known that the tool had not activated until the section

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**Underreaming Risks and Probability of Occurrence with Tool**

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<tbody>
<tr>
<td>Consequence</td>
<td>Stuck BHA, LIH BHA, Sidetrack</td>
<td>Trip, Sidetrack, Loss of target</td>
<td>Trip, Fishing, Sidetrack</td>
<td>Stuck BHA, DBR</td>
<td>during R/I/H/shoe drill</td>
<td>Trip, DBR</td>
<td>Trip at depth</td>
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<tr>
<td>Probability</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
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<tr>
<td>Consequence</td>
<td>Re-ream sections, Trip</td>
<td>Unable to reach TD</td>
<td>Trip DBR</td>
<td>Poor hole condition, Stuckpipe</td>
<td>Trip</td>
<td>Stuck</td>
<td>Trip, LIH LWD</td>
</tr>
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Figure 5 Shows Underreaming Risks and Probability of their Occurrence with the Tool
had reached TD. An average industry wide statistic shows that this occurs in 1 out of 10 jobs.

The secondary cause of NPT was ‘Cutter block or component loss’. In certain instances, this was only noted due to abnormal metal content being recovered on the shale shakers. However, at that point the cause of the problem was unknown.

In the case of the problematic runs, these two failure modes are not known until the section has reached TD and the morning report is in. According to a major deepwater operator the likelihood of underreamer complications is three-fold as compared to non-underreaming jobs. If consideration is given to the actual downtime for the total number of underreaming failures i.e. based on 10% of Total Jobs the potential savings mount up (excluding LIH charges).

Taken individually or collectively, this data created a convincing case for a direct and real-time way of knowing what is actually going on downhole especially with regard to underreaming.

Additionally, greater emphasis should be placed on identifying NPT for consecutive activities i.e. running casing or expandables and establishing the root causes of NPT. This is interesting as there can be a race to get to TD. However, where does casing running NPT actually get allocated? The same applies to problems created by excess cement volumes due to undergauge hole.

**New Technology**

The new technology aims to reduce risks associated with much of these NPT causes. The development of the technology for use in all rotary BHA types will be a step-change in drilling efficiency by reducing NPT and allowing the driller to take decisions earlier in order to maintain the wellbore within the desired diameter. The purpose of the new technology is to provide a new generation underreamer which will automatically detect and diagnose variations in wellbore diameter and rugosity. (See Figure 5)

Specific problem solving in real-time covers:
1. Probability of the tool not activating/staying deactivated
2. Probability of component loss
3. Probability of underreamer not delivering gauge hole
4. Probability of underreamer being unable to cope with hard formations
5. Probability of stuckfish due to radial closure
6. Probability of excessive overpull being required
7. Probability of poor hole cleaning/balling CFD/cuttings beds
8. Probability of being unable to backream
9. Probability of premature activation
10. Probability of exceeding circulating life

**Field Development Applications**

- Expandable liners. Undergauged hole size is not acceptable for these type of expandable applications and would jeopardize expansion.
- Close tolerance casing schemes
- Standard gravel packs or sand screens to avoid loss of production
- Exploratory wells such as those drilled in deepwater mature assets or radial shrinkage zones i.e. salt or swelling shale can offer a primary application for the technology. Even when a full logging suite is run LWD measurements are taken after underreaming.

**Expandables**

Expandables are typically a single shot at expansion which are set in place and expanded to the required diameter with push-down or pull-up expansion cone. Any part of the wellbore diameter that is undergauge may lead to possible failure in tubular expansion and the complete loss of the section Ref 11 and 12.

The new technology reduces the risk by pinpointing undergauge hole sections and allowing for re-reaming until they are in-gauge. This increases the overall effectiveness of expandables. The technology would also improve drilling efficiency by reducing the NPT associated with casing running due to undergauge hole.

**Wellbore Instability**

The technology could also be very useful in addressing wellbore instability issues. It allows for timely understanding of breakouts, vugs, loss zones and washouts etc allowing for better drilling practices and more cost effective well construction. With the expandable application or narrow PPFG gradients this can be very useful in real-time optimisation of casing points.

**Technology Summary**

Optimisation of underreaming and associated calliper operations using Integrated and Intelligent system involves:

- Underreaming in Subsalt and other formations for Close Tolerance Casing, Expandable Liner Sections – a total of more than 21 applications
- The technology can be operated as a stand-alone system using its own mud-pulser and measurement means. The generation II design will interface with standard mud...
Reducing Uncertainty and Cost in Drilling and Completion

pulsing technology provided by major service companies
• Designed to operate in all wellbore types and conditions as well as handling vugular formations and all drilling fluid types
• Enables the identification of borehole diameter variations without having a separate calliper and/or LWD run or LWD delay of post underreaming
• Reduced drilling costs through the need for fewer underreaming correction runs from early detection of borehole diameter and failure modes
• Ensure hole opening by real-time monitoring of underreaming operation
• Automatic diagnostic and troubleshooting using logic circuit
• Greater operational flexibility ie run with low flow/hi flow, low WOB/high WOB

Conclusion
NPT analysis should consider root causes as well as their knock-on effect on sequential activities. The new technology reduces costs and removes uncertainty associated with underreaming. It also provides data that can be sent straight to Real-Time Operations Centres. It solves a growing drilling problem in the underreaming market which is itself a simple choice, either sections are underreamed and the target is reached, or, it is not. Therefore, there is a recognised need for underreaming, and a compelling case for reducing the NPT and costs associated with underreaming. In the current oil price environment the ability to reduce costs by optimising drilling efficiency will only grow in importance.

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Welcome from the General Chairperson

Dear Colleagues:

On behalf of SPE and the program committee, it is with great pleasure that we invite you and your organization to join us at the 2009 SPE Latin American and Caribbean Petroleum Engineering Conference (LACPEC), scheduled from May 31st to June 3rd in Cartagena de Indias, Colombia.

The theme of our three day multidisciplinary technical program is “The Power of Integration is Energy.” LACPEC focuses on the maximum production and recovery of oil and gas in the Latin American and Caribbean regions through the integration of people, technology, assets, and organizations.

More than 27 specialized technical sessions will cover aspects of integration, energy, and research and development, as well as a number of overarching industry issues and integrated project management themes. These sessions are led by a program committee comprised of individuals from leading corporations and research organizations from all over the region.

This conference is not only appealing on a regional level, but also on a global level since the region’s crude oil production—currently constituting 13% of global production—is steadily increasing.

LACPEC features more than 180 technical paper presentations, posters, and panel sessions that will cover categories such as deepwater developments, gas technologies, heavy oil, mature fields, naturally fractured reservoirs, smart fields, unconventional resources, and water management. In addition to the technical sessions, the conference will also include a young professionals workshop and student paper contest.

It will offer your personnel the chance to learn and share knowledge, and to discuss the challenges influencing and shaping our region, by attending the technical sessions or by networking with colleagues from around the world.

LACPEC is an ideal venue to showcase your company’s latest technological accomplishments, products, and services. Through exposure to regional oil and gas providers, regional energy officials, and international executives, you can sharpen your business strategy and leverage your goals. This year’s conference promises to be a remarkable and beneficial 3 days for all who attend.

We look forward to seeing you this June in Cartagena, Colombia.

Sincerely,

Néelson Navarrete, Ecopetrol

LACPEC 2009 General Chairperson

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Mario A. Vasquez, Pemex E&P
Javier Velarde, Repsol
A.J. (Sandy) Williams, Artificial Lift Performance
Seferino Yesquen, Petrobras Energia Peru
Young Professionals Workshop

0800–1600, 31 May 2009

The Young Professionals Workshop—for professional members 35 years of age and younger—will have activities and speakers geared especially towards the audience’s needs and interests.

The workshop will include an energetic keynote speaker who will discuss a range of topics, from economic cycles to industry trends. Following the keynote speaker, panel speakers from different sectors of the field (national oil companies, independent oil companies, research and development, academia, and others) will lead discussions about their personal experiences within the field. They will relay these experiences in a manner which will allow the workshop participants to apply the panel speakers’ knowledge to their personal careers.

After breaking for lunch, young professionals will return and separate into groups to prepare an analysis of a given topic that was introduced during the panel session. By the end of the workshop, the participants will have improved their soft skills, technical knowledge, and teamwork skills.

Please note: the young professionals workshop will not have simultaneous translation.

### Workshop Schedule

<table>
<thead>
<tr>
<th>Time</th>
<th>Subject</th>
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<tbody>
<tr>
<td>0830</td>
<td>Breakfast /Coffee</td>
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<tr>
<td>0850</td>
<td><strong>Opening Comments/Introduction</strong></td>
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<td></td>
<td>Chairman: Wajid Rasheed, EPRasheed</td>
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<tr>
<td>0900</td>
<td><strong>Keynote Speaker</strong></td>
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<td></td>
<td>Jose Formigli, Petrobras</td>
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<tr>
<td>0930</td>
<td><strong>Introduction to Oil and Gas Industry in Central and Latin America and Colombia</strong></td>
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<td></td>
<td>Speaker: Nestor Saavedra, Ecopetrol</td>
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<td>1000</td>
<td><strong>NOCs, IOCS, Global Oil and Gas Industry Reserves</strong></td>
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<td></td>
<td>Speaker: Wajid Rasheed, EPRasheed</td>
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<td>1030</td>
<td>Coffee Break</td>
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<td>1100</td>
<td><strong>Innovative Approach for Integrated Studies: Event Solution</strong></td>
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<td></td>
<td>Speaker: Ghazi Al Qahtani, Saudi Aramco</td>
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<td>1130</td>
<td><strong>Career Challenges and How to Overcome Them</strong></td>
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<td>Speaker: Ana Zambelli, Schlumberger</td>
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<td>1200</td>
<td><strong>LUNCH</strong></td>
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<td><strong>Young Professionals and R&amp;D: What Can Be Done to Meet the Challenges?</strong></td>
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<td>Speaker: William Cobb, 2008 SPE President</td>
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**Afternoon breakout sessions**

Individual groups will discuss predetermined topics, make a SWOT analysis, and then a 5-minute presentation.
Reserves, Peak Oil and Medieval Maps

Here follows a chapter from The Hydrocarbon Highway, by Wajid Rasheed

Are we running out of oil? Before we can answer that question, we need to understand what oil and gas reserves are and how they are measured.
What are Oil and Gas Reserves?

Reserves are very significant numbers. They form the base of a slew of Key Performance Indicators (KPI) for all types of oil companies. Yet, the lack of a globally accepted standard makes the measurement and auditing of reserves a thorny and contentious issue. An integrated understanding of world wide reserves is also lacking. In this chapter, we consider reserves measurement systems, global reserves and ‘peak oil’. One key question interests us: are we navigating through global reserves using a ‘medieval’ and outdated map? If so, is peak oil a physical or psychological shortage? Invariably, reserves* grab headlines due to their financial significance, measurement methods or geo-political dimension. On the one hand, the sustainability of oil companies depends on reserves and, on the other, oil company profits depend primarily on production**. By breaking down reserves and production data, analysts can derive KPIs such as net worth, reserves to production ratio, reserves replacement and production quotas and positive cash-flow. Consequently, reserves and production are inextricably linked to financial performance.

Major, National and Private

Existing irrespective of oil company size or shareholding, the link between reserves and financial performance is a fundamental one. Majors, public or ‘floated’ companies, will be judged by analysts on their short-term earnings and long-term prospects. Private companies will be judged by shareholders on Return on Investment (ROI). National or state companies are subject to analysis too which we will consider shortly. The stock prices of oil companies are heavily influenced by their stock in-trade—oil. The oil company itself will use KPIs such as production rates and reserves replacement to make financial valuations and earnings projections. Financial analysts ultimately look to these figures and make ‘buy, sell or hold’ recommendations. Reserves, therefore are a major influence on the stock price of major International Oil Companies (IOCs). Of course, IOC stock prices will be affected by quarterly profits and shareholder dividends. The oil price and other contextual factors that affect the attractiveness of the industry as a whole for investment—geopolitics, speculation and ‘futures’ trading—will also affect stock ratings. Beyond annual profit concerns, the long-term survivability of the oil company is wholly dependent on the rate at which production and reserves are increased. Usually this happens in one of three ways: first, through the ‘drip-feed’ of incremental recovery using mature field improved technology; second, by boosting reserves through the bit which means that successful wildcat strikes open new frontiers; and finally, by the acquisition of another oil company through its stock.1

National Oil Companies

There is a common yet incorrect perception that National Oil Companies (NOC) are somewhat immune from scrutiny of financial indicators; however, there are at least two scenarios where NOCs will be judged by analysts. This primarily occurs when financial experts assess financial risk and assign credit ratings to NOCs and their countries of origin. In major oil exporters, i.e. exporting more than 2 million barrels of oil per day (MMbbl/d), the NOC is often the largest business in the country*. Country risk can therefore be considered a function of the NOC’s performance. This has a direct bearing on the credit rating of countries. A secondary situation occurs when analysts assess the attractiveness of financial instruments or debt (bonds), issued by the oil company or government, based on ROI and risk.

Certain NOCs, such as those within the Organisation of Petroleum Exporting Countries (OPEC), also depend on reserves in another way. OPEC production quotas are allocated as a proportion of total proved reserves. Consequently, countries with high reserves volumes are given higher thresholds of production.2,3

Uncertainty

Measuring reserves is difficult and involves a basic uncertainty because reserves lie hidden away in deep subterranean reservoirs. It would be physically impossible to accurately measure oil and gas in place; therefore, the industry relies on extrapolated measurements as accurate measurements can only occur upon production. Consequently, measuring, corroborating and auditing the measurement of reserves is an inexact science.

To make matters more complex, there is no single standard or methodology that is universally accepted by the industry or by the financial community, i.e. regulators/analysts. Substantive variations exist between institutions and nations. Exemplifying this are differences between the SPE (Society of Petroleum Engineers) and SEC (Securities Exchange Commission) criteria for reserves classification, and international variations between the Russian and Norwegian systems.4,5

Before we go into detail, it is fair to note that the lack of a single international or institutionally recog-

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*R reserves estimation is a sensitive area and the definition of related terms attracts considerable debate from both inside and outside the industry. For our purposes, we use the term reserves to mean proved reserves. See below for reserves classifications.

** Other factors include oil price, industry costs, inflation and efficiencies of scale.
nised set of standards makes reserves measurement somewhat dependent on the system chosen.6

**Missing Barrels**

With many oil companies based in the US or floated on US stock markets, the oil industry has been lobbying US regulators to overhaul the system by which the industry’s reserves are measured.7

The SEC classifies reserves using conservative and narrow definitions that do not satisfactorily account for the role of E&P technology in finding and producing reserves. This is a problem because not only does the industry have a track record of technology development, but technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond Earnings Before Income Tax Depreciation and Amortisation (EBITDA). Peak oil theorists also tend to minimise the value of E&P technology. We will examine the value of technology in detail shortly in the ‘medieval map’.

The SEC measurement leads to a substantive variation with internal industry measures such as the SPE which places more emphasis on technology ‘unlocking’ reserves to make them more recoverable. The variation often results in discrepancies that amount to billions of barrels of oil across the industry.8

Industry analysts have lobbied the SEC to change its reserves accounting so that the benefits of E&P technology can be better applied. Essentially, this covers a raft of technologies such as seismic, geosteering and horizontal drilling which enable higher recovery rates through pinpointing reserves and well placement.9 At issue is the realistic valuation of energy companies themselves, as well as how we calculate replaced or future reserves. While analysts look to earnings as a short-term performance measure, the more long-term measure looks to reserves to production ratios as the basic indicator of the oil company’s future wealth.

**What’s On the Books?**

Due to the way financial and technological factors impact on reserves measurement, it is worth reviewing the types of reserves classifications that ultimately lead to KPI and valuation.

**Getting a Slice of the Pie**

It is worth distinguishing between the ‘global resource’ or size of the pie which refers to the total volume of original oil and gas in its natural state and ‘global reserves’ or ‘the slice’ which refers to the percentage of the resource that is recoverable using today’s technology at today’s cost-price structure. According to OPEC and the BP Statistical Review 2008, worldwide reserves are 1.2 trillion barrels (defined as proven or developed reserves) and 6263 tcf of natural gas. The US Geological Survey, however, places the global resource on oil initially in place at 3 trillion barrels. We will come back to the size of the pie in the context of peak oil; however, for now it is worth noting that reserves are ranked based on their ultimate probability of production. That is to say one day in the future they will be brought to surface and sold*

Once the resource is discovered, reserves need to be booked. This process involves mapping out and visualising one or more underground structures (leads or prospects) that may extend over 200 square miles. Reserves must then be classified and assigned values according to the probability of their production. Finally, the value of reserves are discounted to today’s worth. For financial and asset planning purposes, the key determinants are the likely size of discovered reserves and their ease of recovery.10 The most common classifications are the generic three ‘P’s and the more specific ‘P factor’.

**The Three ‘Ps’**

Defined according to a sliding scale of the ‘probability’ or percentage chance of production, the three ‘Ps’—Proved, Probable and Possible—are illustrated by the figure below. They indicate the relative ease or difficulty with which the reserves in question can be produced. It is standard practice for a numerical ‘P factor’ to be assigned to represent the specific probability of the reserves being produced. Typically, ‘P’ values for ultimate recovery range from P90 for a very high probability, P50 for medium probability and P10 for a very low probability. A series of questions related to location, accessibility and technology need to be answered before ‘P’ values can be ascertained. Are the reserves located in easily accessible areas or shallow depths? Are there wells, platforms or pipelines in place? Does the technology exist to reach the reserves today? If the answer is ‘yes’ to these questions, the probability of production is clearly high so these are proved reserves. Where the answer is ‘no’ and nothing is in place other than outline plans, such reserves are low probability. Most reserves will fall between these two extremes in that they have varying degrees of infrastructure in place.

Corresponding to a value, i.e. P90, P50 or P10, the ‘P factor’ simply represents the percentage chance of reserves being produced. Proved is 90%, Probable is 50% and Possible is 10%.11

This classification uses a scale based on the development status, the infrastructure in place and the ease of recovery of oil and gas. Reserves that score lower on development status and infrastructure are harder to develop so their percentage chance of recovery falls; therefore, they are assigned a lower ‘P’ class with a lower ‘P’ value.

‘Proved reserves’ refer to the estimated quantities of crude oil, natural gas and Natural Gas Liquids (NGLs) which can be recovered with demonstrable certainty using geological and engineering data. This applies, for example, to future production from known reservoirs under existing economic and operating conditions, i.e., oil pric-
Reservoirs are considered 'proved' if economic production is supported by actual production or conclusive formation tests showing an increase in production. The area of a reservoir considered proved includes: the portion identified by drilling and defined by gas-oil and/or oil-water contacts and the immediately adjacent areas not yet drilled, but which can be reasonably expected as economically productive based on the available geological and engineering data.

Reserves which can be produced economically through improved recovery techniques (such as water injection to maintain reservoir pressure) are included in the 'proved' classification when an increase in production is seen. Estimates of proved reserves do not include the following: oil that may be produced from known reservoirs but is classified separately as 'indicated additional reserves'; crude oil, natural gas, and NGLs, the recovery of which is subject to uncertainty as to geological, reservoir characteristics, or economic factors; crude oil, natural gas, and NGLs that may occur in undrilled prospects; and, crude oil, natural gas, and NGLs that may be recovered from unconventional sources such as oil shales.

Further distinctions blur the boundaries between classes; for example, 'proved developed reserves' refers to reserves that can be recovered from existing wells using existing technology. Additional oil and gas production obtained through the application of improved recovery techniques can be included as 'proved developed reserves' only after successful testing. Tests can either be pilot projects or improved applications that show an actual increase in production.

'Proved undeveloped reserves' are reserves that are recoverable from new wells on undrilled acreage, or from existing wells where further major expenditure is required. Reserves on undrilled acreage are usually limited to those areas where there is reasonable certainty of production when drilled. Proved reserves for other undrilled units can only be claimed where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.
**Russian and Norwegian Reserves Classification**

Russian and Western methods of estimation and classification of reserves are somewhat different. The Russian officials have divided oil and gas reserves into six classes: A, B, C1, C2, D1 and D2. Class A represents proven reserves and B provable reserves. Class C1 represents reserves estimated by means of drilling and individual tests, and C2 reserves are based on seismic exploration. Classes D1 and D2 represent hypothetical and speculative reserves.13

Norway uses its own definitions of reserves, which run from Category 0 – 9.14

Category 0 is defined as ‘Petroleum resources in deposits that have been produced and have passed the reserves reference point. It includes quantities from fields in production as well as from fields that have been permanently closed down’.

Category 9 includes resources in leads and unmapped resources and covers undiscovered, recoverable petroleum resources attached to leads. It is uncertain whether the leads, and if so the estimated resources, are actually present. The resource estimates reflect estimated volumes multiplied by the probability of making a discovery. This probability must be stated.15

**Geologic Assessment Procedures**

Oil companies often use models to assess geologic structures or oil and gas plays. A common model defines a play as ‘a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal properties such as source rock, migration patterns, timing, trapping mechanisms, and hydrocarbon types’.

Oil companies use this approach to process exploration knowledge such as seismic or aerial surveys or wildcats generated by the exploration teams. A fundamental part of this process is the attributing of probabilities for each petroleum play. Geologists will also assign subjective probability distributions to characterise attributes of undiscovered conventional oil and gas accumulations.16

The geologic risk structure is modelled by assigning a probability to each play. This probability is based on at least one accumulation meeting the minimum size requirements (50 MMBO in place or 250 BCF gas recoverable). In particular, the oil company will assign probability distributions for reservoir attributes such as net reservoir thickness, area of closure, porosity and trap fill.

Net pay estimates are derived from the data and include the extent and distribution of the reservoir. These estimates are essentially refined and related to P values, i.e. P90, and are verified to see whether they are consistent with existing knowledge. Other factors to be considered will be hydrocarbon recovery factor, porosity and permeability forecasts and initial production.17

**Peak Oil and Medieval Maps**

Since the publication of Hubbert’s Peak in 1956, the theory of ‘peak-oil’ has gained in importance with a growing chorus of support from within the industry and wider society. Yet is peak oil really a physical decline in production levels or is it a philosophical debate mired in the minutiae of reserves and production systems? To answer these questions, we need to adopt a global E & P perspective that integrates prospective E & P areas with technology applications. Equally we need to recognise the limits of conventional wisdom. Are we navigating with a ‘medieval map’ of worldwide hydrocarbon reserves—one that does not adequately reflect the total resource?18

**Optimist or Pessimist?**

Two schools of thought exist. Optimists state there is an abundance of oil and gas and that there is enough for everyone, while pessimists state there is a deficit and we are doomed. These two positions, and the consequent debate, have generated much emotion, not to mention a multi-million dollar niche industry. What appears to be important here is that no-one disagrees that a peak or decline will occur, that is the natural state of systems. Yet, no-one can agree on when or even why this event will occur. It is worth considering this debate as it can help us understand the ‘psychological supply shortfall of prospects. This has a knock-on psychological effect on supply which is compounded by a herd mentality within the oil and gas markets (see Chapter 12: Paper Barrels for detail).

The pessimists reason as follows:

1. Rare conditions allow petroleum reserves to be produced.
2. Once production peaks, reserves decline rapidly in output.
3. Most global petroleum reserves have peaked. Further large finds are unlikely.
4. Global production is therefore declining.19

The optimists argue:

1. Rare conditions allow petroleum reserves to be produced.
2. Production can be made to plateau, not peak, through technology.
3. Technology finds more reserves, makes smaller reserves more accessible and sustains overall production on a global scale.
4. Global production is therefore sustainable.20

There is also a third, or alternative view, to consider:

1. Rare conditions allow petroleum reserves to be produced.
2. Today’s theories regarding petroleum reserves and recoverability are incomplete.

3. Knowledge increases over time.

4. Many prospective petroleum plays are unexplored.

5. All known sources of petroleum systems have therefore not yet been quantified; hence, the use of the ‘medieval map’ analogy.21

In this alternate scenario, no one can state categorically that peak oil has, or has not occurred because our current knowledge is incomplete. Just as when we look at medieval maps and note the Americas are missing, so future generations will look at today’s map of worldwide reserves as incomplete. Just as when previously wise petroleum engineers looked at deep-water reserves and shook their heads deeming them unrecoverable, we see the limits of their wisdom.

Deepwater production has been made routine, almost mundane through ‘gamechanging’ and cost-effective technology. This ranges from pre-drill packages that incorporate sub-salt imaging to seabed to surface risers to directional drilling techniques that can enable multiple reservoir completions.

In this way, the ultimate recoverability of reserves is tempered by the cost of technology. If E & P technology can be made available at cost-effective prices, reserves can be developed. This is because finding and lifting costs ultimately determine development. If the costs of development outweigh the price of oil, there simply is not enough profit to develop them.

As noted earlier, the SEC classifies reserves according to very narrow definitions that do not satisfactorily account for the role of E & P technology in finding and producing reserves. Peak oil theorists tend to use such classifications too.

Peak oil theorists tend to overlook the industry’s track record of technology development. Technology is the stock-in-trade of the service companies and a principal measure by which analysts derive multiplier or share valuations of service companies beyond earnings.

This does not imply that petroleum is infinite. It means that even though petroleum is a finite and scarce resource, technology can increase production and ultimate recovery.

Aside from the technology factor, there is the question of the medieval map of reserves. As our globetrotting exercise will show shortly, there are still several petroleum provinces waiting to be mapped out.

Given that demand for oil and gas will rise in the long-term, and considering the track record of the E & P industry to date, further advances in E & P technology will permit almost all petroleum reserves, irrespective of location, to be developed before new energy sources and exits to the Hydrocarbon Highway are created. Consequently, the limiting factor for reserves will be the cost of development rather than their shortage.

**Worldwide Reserves**

Referred to as ‘the low hanging fruit’ that is effortlessly picked, onshore basins are generally easy-to-access with low finding and lifting costs. Consequently, these reserves have been both extensively characterised and produced; however, several tough-to-reach onshore basins remain unexplored. Exemplifying this is the Amazon Complex (Brazil, Colombia, Peru and Bolivia), the Arctic Circle (the Alaska National Wildlife Reserve being part of this territory) and Antarctica.*22

No one has any real knowledge on the potential size of these onshore reserves. The historic finding and lifting costs in similar areas such as Sakhalin or Alaska, however, range on average from US $12 to US $18. With production, total costs rise further due to a lack of infrastructure in remote areas (see Chapter 8: Extreme E & P for detail).23

**Middle East**

More prospective areas exist in unexplored basins within the Middle East such as the Empty Quarter (Rub Al Khali) in Saudi Arabia, the Bushehr province in Southern Iran and North and South Iraq. Typically, these countries are blessed with prolific source rock, high permeability and trapping systems found at very shallow depths starting at approximately 700 m (2,100 ft) and ranging to 2,000 m (6,000 ft). New finds continue to maintain the Middle East as a dominant long-term reserve base, with common recognition that Saudi Arabia and Iran respectively are the world’s largest and second largest holders of oil reserves. Further, finding, lifting and production costs are the lowest worldwide, averaging between US $1 to US $3 a barrel.24
Lifting costs can vary, however, by way of comparison. In other relatively low-cost areas like Malaysia and Oman, lifting costs can range from US $3 to US $12 per barrel to produce. Production costs in Mexico and Russia might potentially be as low as US $6 to US $12 per barrel (higher under current production arrangements by local companies). 25

By reviewing the world’s prospective shallow coastal waters, deltas and oceans, it becomes clear that our map of global resources is incomplete. In the offshore realm, there are many unexplored basins with finding, lifting and production costs varying from US $18 to US $25 per barrel for certain deeper waters. Large tracts off the coast of West and North Africa are undeveloped. The West African margin has been extended from the high-profile plays in the shallow waters of the Niger Delta, Nigeria and the Congo Basin, Angola to deeper waters and to highly prospective sub-salt plays. Mauritania and Tanzania are other examples where new discoveries have been made. 26

South of Australia in Tasmania, oil companies have been studying gas plays since 2000 which had previously been neglected due to the search for oil. This has led to indications of oil being found in Africa near Madagascar, which has been identified as a potential new petroleum province. 27 Mauritania and Tanzania are other examples where new African discoveries have been made. Another area is offshore Morocco, where the deposition of an ancient river system was found over salt. A mobile substrate, either salt or shale, is a key element all along the West African margin because it provides geological factors necessary for oil and gas. 28

**Continental Plate Reconstruction**

A clear example of continental plate reconstruction and conjugate oil and gas of plays is offshore West Africa and offshore Brazil. By using reconstructions, it can be seen that the Rio Muni Basin was the ‘mirror’ basin to the Sergipe-Alagoas Basin in Brazil, and the Congo Basin to the Campos Basin. By repeating this process along the coast of West Africa and Brazil, several emerging oil and gas plays can be drawn up. These include the subsalt frontiers of offshore Brazil including Tupi. Although production is not likely to make a major impact on world oil exports over the next decade, the point is that new frontiers have been discovered. 29

In Central America, the offshore area between Venezuela and Trinidad, the Gulf of Paria, is largely unexplored as are the waters off Colombia and Peru. 30

The Gulf of Mexico (GOM) has unexplored waters that stretch from the shallow waters off Florida, US and move into the territorial GOM waters of Cuba, vast areas of deep waters in the Mexican GOM and the deeper waters of the US GOM. Within the US GOM, the sub-salt play has been instrumental in new finds.

Offshore production in areas like the North Sea with offshore platforms, can run to US $12 to US $18 a barrel. As reservoirs become smaller, those costs tend to rise. In Texas and other US and Canadian fields, where deep wells and small reservoirs make production especially expensive, costs can run above US $20 a barrel.

Further East, we note that certain areas of the Northern North Sea and the Barents Sea are still to be explored. While in Russia, Sakhalin Island, the Central Asian Republics, the Red Sea, the Persian Gulf, the Indian Ocean, Offshore Australia and New Zealand, several offshore basins represent prospective yet unexplored areas. 31

What is the total resource base? The US Geological Survey puts this at 3 trillion barrels of oil. Again, it’s hard to say because we are still waiting to finalise the map. Sweating The Finding and Development in Figure 5 clearly shows that, when crude oil prices fall below US $20 a barrel, many areas become unprofitable and production is reduced if not halted altogether. Only certain lower cost areas can remain profitable and hence maintain production during a ‘good sweating’ period. 32

Two factors emerge from this globe-trotting exercise: first, there is a lack of characterisation in many highly prospective basins and gulfs; and second, there is high prospectivity, but it is tempered by technical limitations and increased costs.

None of these areas is mature; most are unexplored and some are even unlicenced. This is despite adjoining proven hydrocarbon producing basins or sharing geological characteristics such as source rock, trapping and faulting. It is fair to say that we have not yet characterised the world’s oil and gas basins nor their accompanying reserves. Consequently, how can we even assume that global peak oil production has occurred? (Gas is another matter entirely as it can be man-made).

**Conventional Wisdom and the Limits of Our Map**

The limitations of our map of oil and gas reserves start to become clear when we consider past theories. In the 1990s, one widely held view stated that offshore oil and gas reserves would not be found at extreme conditions, i.e. depths exceeding a TVD of 20,000 ft (6,096 m). It was suggested that overburden pressures would either cause a loss of hydrocarbons due to migration to shallower traps or compaction. 33 Now that theory has changed because oil and gas trends have been located at far greater depths than prior knowledge would indicate. Think deep gas, US GOM.

In the 1980s, another example of a change in think-

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* Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and will not be developed until 2048. The call for an environmental protocol to the Antarctic Treaty came after scientists discovered large deposits of natural resources such as coal, natural gas and offshore oil reserves in the early 1980s.
ing occurred concerning the flow paths of fluvial deposition. Ancient river systems account for the sedimentation that leads to accumulations of oil and gas. In river deltas worldwide, as the shallow water plays were developed, exploration efforts evolved into the deepwater usually with only major international oil companies that could qualify for the blocks.

Smaller oil companies, therefore, were limited to exploring other geologic scenarios and plays. They recognised that over time the places where these river systems had been depositing sediment had changed, and the Independents’ exploration discovered ‘new’ margins. Another example of limited knowledge has been sub-salt basins. These have been discovered and are being explored in the GOM and worldwide. Sub-salt plays in West Africa, Brazil and GOM show deeper accumulations of oil and gas trends that had not been predicted or expected earlier.

**Game-Changing Technology**

Back in the late 1980s, it was thought that development of thin sands such as ‘Norwegian Troll oil’ would never be economically feasible, because the oil reserves were so thinly layered and the price of oil was US $10 per barrel.

Game-changing technology such as 3D seismic improved the visualisation of reserves, while horizontal drilling and geosteering altered the definition of what was deemed uneconomic or unreachable at a given time.

The billion-dollar think tanks and research and development facilities that major service companies own are continually creating new technologies that help access reserves previously considered uneconomic or unreachable. Service companies and operators develop technology in-house through joint industry projects and with best-in-class companies; for example, Shell and Petrobras respectively are involved in the monobore and the Procap 3000 initiatives—two examples of technology cascading downward. Underlying the monobore (a vision of drilling and casing a single-diameter well from top to bottom) is the creation of businesses to develop the downhole tools, tubes and markets for expandable tubulars.

Procap 3000, a range of exploration and production technologies, is paving the way in ultra-deepwater development. Drilling contractors have introduced simultaneous drilling and completion of two wells by way of the dual-activity derrick system.

**Technology**

Scarcity of oil reserves and increasing reserve replacement costs are the twin factors that have accelerated the technological evolution of E&P and enabled extreme E&P (see Chapter 8: Extreme E&P). This evolution is most clearly visualised in the dramatic shift from onshore to offshore exploration. The incredible depth progression from land to shallow coastal waters to deep waters to the extremes of ultra deepwater is shown in the graphic overleaf.

A few decades ago, it was not considered possible to produce in waters beyond 6,561 ft (2,000 m) depth, and accordingly, those reserves were listed as ‘P 10s’ with a very low possibility of production. Rigs and risers were just some of the incredible challenges. The industry has, however, progressively tapped deepwater accumulations. First, it targeted shallow onshore reserves as the less challenging ‘low-hanging fruit’. As those resources became scarcer, E&P went deeper onshore and spread to shallow offshore waters. E&P operations in 8,200 ft (2,500 m) water depth are routine, and the challenge now is 9,842 ft (3,000 m) and deeper.

Records are continually set and broken not just in deeper water depths (3,000 m) but also in deep reservoirs below salt domes, tar zones and in the remote basins of the world and in new frontiers.

This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production. Remarkably, however, almost all of this enabling E&P technology is considered an outsourced commodity marketed by service and supply companies, which means the NOCs have no shortage of technology vendors.

The buzzwords of ‘ultra-deepwater, digital oilfield and barrel-chasing’ may first be heard in oil...
company offices due to the engineering challenges and risks oil companies ‘buy’. They resonate most loudly, however, throughout the service-side: in product development, in research facilities and on test rigs before technology is commercially run in field applications.37

In addition to developing the technology to drill in deeper waters, the industry has developed the ability to drill extreme offsets from a single surface location. This has profound implications in reducing our environmental ‘footprint’ and providing economic access to thousands of ‘satellite fields’. As of 2008, the world’s record Extended Reach Drilling (ERD) well was drilled in the Persian Gulf from a jack-up drilling rig.

The total measured depth of the well was 40,320-ft (12,293 m), and the well’s bottom was offset 37,956-ft (11,572 m) from its surface location. In the UK, ERD techniques enabled BP to develop Wytch Farm, an entire oil field under an environmentally sensitive resort and vacation area on the south coast of England, with no visible footprint. Off Sakhalin Island in far east Siberia, Russian companies are exploiting oil reservoirs from land by drilling ERD wells out under sea ice that would ordinarily damage offshore facilities.

These feats were inconceivable to Hubbert when he developed his peak oil theory. Hubbert was correct to state that oil is a finite resource—and he can’t be blamed for letting a medieval mentality affect his prediction of when we would run out. People today who are still letting medieval thinking guide them, however, should know better.

What emerges from the peak oil debate is that we are reading the directions to worldwide reserves from a ‘medieval map’. Clearly, there are new frontiers and plays to be developed. Think Subsalt, Arctic and Deepwater E & P which is changing the definition of P 10’s into P 90’s. Coupling this with innovative thinking and cutting edge technology makes for a convincing argument; peak oil as far as reserves are concerned, is a philosophical debate rooted in a psychological shortage not a physical one.

We are not in fact running out of oil. We have many areas yet to explore before we have to worry about oil and gas shortages. As we have been shown, there are plenty of barrels of oil remaining. The next logical question then would be ‘What is in a barrel of oil?’ Everyone always talks about barrels, but no really talks about their composition or how this affects recovery.

Figure 6 - The Incredible Depth Progression from Shelf to Deep Waters (Petrobras News Agency)
Notes and References

CHAPTER 2 - RESERVES, PEAK OIL AND MEDIEVAL MAPS


2. The OPEC Statute requires OPEC to pursue stability and harmony in the petroleum market for the benefit of both oil producers and consumers. To this end, OPEC Member Countries respond to market fundamentals and forecast developments by co-ordinating their petroleum policies.

3. See Booklet: What is OPEC? Production regulations are simply one possible response. If demand grows, or some oil producers are producing less oil, OPEC can increase its oil production in order to prevent a sudden rise in prices. OPEC might also reduce its oil production in response to market conditions. Public Relations & Information Department, OPEC Secretariat, Obere Donaustrasse 93, A–1020 Vienna, Austria. Tel: +43 1 211 12-279, (www.opec.org).


6. There are as many as 7 different reserves classification systems in practice.

7. The SPE is seeking to overhaul and standardize current classification methods.

8. The Industry is lobbying the SEC for a rule change.

9. E & P technology clearly make reserves more accessible. The problem is at what cost? The issue is not simply related to oil price v technology cost but certainly more account should be made of the role of technology and reserves classifications.

10. This is what determines asset valuation and cash flow.

11. Standard knowledge in the industry.


15. Ditto.


17. Plays and Concessions—A Straightforward Method for Assessing Volumes, Value, and Chance, P. Jeffrey Brown and Peter R. Rose


19. Communications with Dr Colin Campbell, one of the leading voices of Peak Oil.

20. Optimists.

21. This is the Authors own view. The three P’s are commonly recognized measures of probability of production.

22. Clearly, at some point Antarctica will be opened up for E & P. See The Petroleum Potential of Antarctica, Macdonald, David University of Aberdeen, UK.

23. Remote projects that I have worked on i.e. Brazil Foz de Amazonas, Amazon, have had the lack of infrastructure create major problems for planned operations and unplanned events.

24. From both IOC and NOC data.

25. These are not replacement costs but historic costs. Report on UK Sector NWECS 2000 Wajid Rasheed.

26. See Brazil Oil and Gas Issue 1, Interview with Petrobras International Executive Manager Joao Figueira (www.braziloilandgas.com).

27. See The Tectonic and Paleogeographic Context of Madagascar Petroleum Systems, Hoult et al Models of a pre-Jurassic Gondwana fit range from a palaeo location for Madagascar off Mozambique (Flores, 1970) to that of Reeves et al. (2004) who like most current authors, place Madagascar off the Kenya/Somali coast. The precise tightness of fit is still a matter of debate.


29. See Brazil Oil and Gas Issue 11 p 6 Tupi’s recoverable volume of 5 to 8 billion barrels of oil equivalent may place Brazil in the select group of petroleum exporting countries (www.braziloilandgas.com/issue10). In 2008, Petrobras announced new oil discoveries in the Santos, Espirito Santo, Campos, and Jequitinhonha Basins. In the Santos Basin pre-salt layer alone, the company estimates recoverable volumes of 9.5 billion and 14 billion barrels of oil and gas in barrel equivalent in the Tupi, Iara, and Jupiter areas. In September 2008, the Company started producing in the pre-salt in the Espirito Santo sea, in the Jubarte Field, located in the Campos Basin.

30. The Identification of The Depositional Environments Of The Cruse, Forest And Morne L’Enfer Formations In The Southern Half Of The Gulf Of Paria, Trinidad, West Indies Curtis Archie, PETROTRIN.

31. Oil from the South: Mesozoic Petroleum Systems, Proven and Potential, in Mid to High Southerly Latitudes Bradshaw, Marita et al. Is there a corresponding belt of petroliferous basins in the southern hemisphere? Notable oil provinces do occur in mid to high southerly latitudes. Oil source rocks include marine
Early Cretaceous shales (San Jorge and Magallanes/Austral basins, South America; Bredasdorp Basin, South Africa) and Late Cretaceous to Eocene coaly sediments (Gippsland Basin, southeast Australia; Taranaki Basin, New Zealand). Frontier Mesozoic rift basins occur in offshore East Africa, along Australia’s southern margin (Bight and Mentelle basins), on the Lord Howe Rise, offshore New Zealand and in the Falklands. Regional studies of the shared history of Gondwana breakup and paleoclimatic and environmental reconstructions can guide exploration in these frontier areas.

34. Gas Beckons in Deep Shallows. Louise Durham Gas exploration to depths of 30,000 ft.
35. The Discoverer Enterprise of Transocean is the first ultra-deepwater drillship with dual activity drilling technology, which aims to reduce the cost of an ultra-deepwater development project by up to 40 percent. Two full-sized rotary tables are designed into a drill floor more than twice as large as a conventional one.
36. The industry is looking at ultra-deepwater as 3,000 m.
37. Harts E & P Mar 2002 Drilling Column, by Wajid Rasheed. 'Small companies and tangled thickets'.
38. See The Medieval Map page 45.
39. Campbell, Peak Oil … Hubberts Peak : The Impending World Oil Shortage Deffyes.
40. Authors notes on acreage in emerging markets.
41. Lifting costs EPRasheed.
42. Idem.
44. AAPG Morocco substrate.
45. Deepwater plays are among the most complex, high cost projects requiring large capital investment therefore favouring large IOCs.
46. Expand your mind, Harts E & P 2004 Wajid Rasheed.
47. Petrobras evolution offshore.
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