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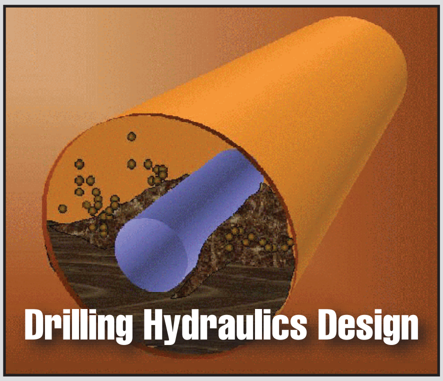
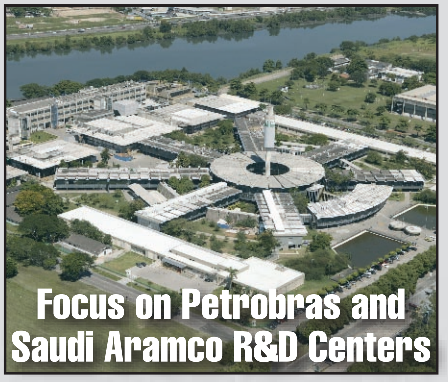
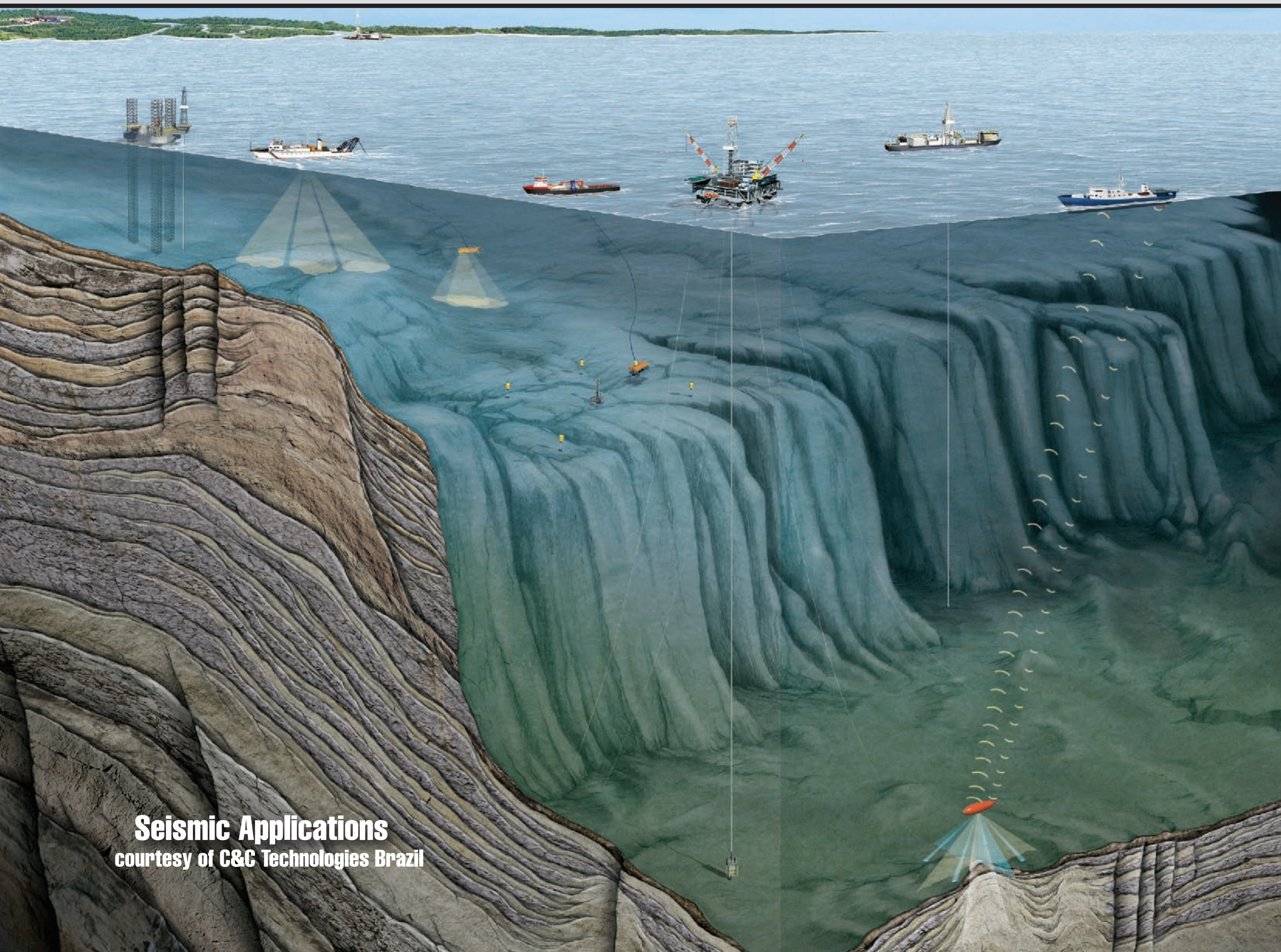


Drilling Hydraulics Design



Focus on Petrobras and Saudi Aramco R&D Centers



Seismic Applications
courtesy of C&C Technologies Brazil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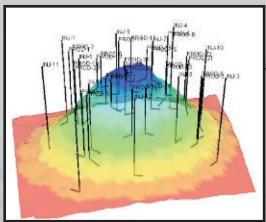

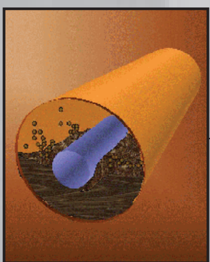

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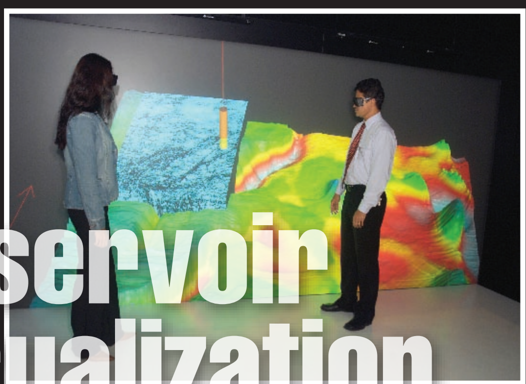

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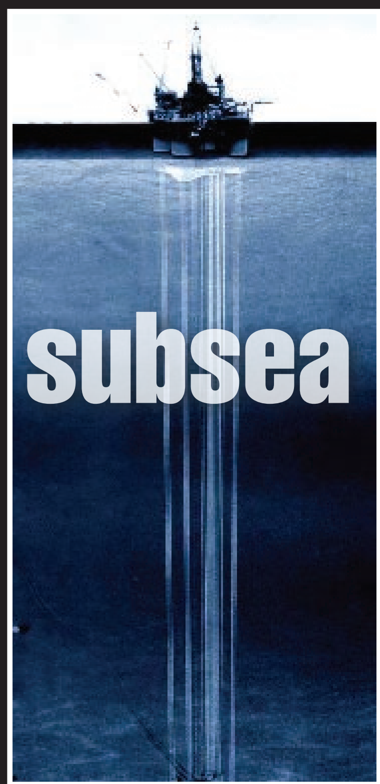

subsea

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Focus on Oil Company R&D Centers

Petrobras and

Saudi Aramco's Research and Development Center (R&DC) recently held the first Downstream Workshop with Brazilian oil company Petrobras. The aims of the workshop were to strengthen the relationship between the two companies, learn about one another's R&D downstream activities, discuss best practices in R&D project management and develop collaborative projects.

> ***"With the memorandum of understanding signed by both companies, Petrobras and Saudi Aramco continue to work together closely," said Omar S. Abdulhamid, R&DC manager. "This workshop will help Petrobras and Saudi Aramco work together to tackle common technological challenges. We especially recognize the potential to gain from the strengths of each other and capitalize on the complementary skills and competencies both organizations have in research and development."***

Under the umbrella of the National Oil Company (NOC) Forum, both organizations are promoting collaboration and addressing challenges facing all NOCs. Saudi Aramco is committed to making the forum a success and acknowledges the leadership role Petrobras demonstrated while heading the NOC Forum's Technology Working Group. Both organizations bring considerable know-how to the technology arena.

The workshop featured presentations and detailed discussions on crude and heavy oil desulfurization, oil-to-chemicals, hydrogen production and clean fuels.

Omar S. Abdulhamid

Representatives of Saudi Aramco's Research and Development Cente
strengthen their relationship.

Saudi Aramco

"I'm very impressed by the arrangement of this workshop and happy with its outcome," said Alipio Pinto Jr., Petrobras R&D Center downstream general manager.

"I'm looking forward to seeing both companies working on at least one collaborative project," he said.

Possible technology projects are:

- *Evaluation and development of catalysers for FCC petrochemicals;*
- *From standard crude produced by the companies;*
- *Evaluation and development of hydrotreatment catalysers for nitrogen removals from heavy oil fractions;*
- *Development of catalysers to convert oil to hydrogen.*

r and the Brazilian company Petrobras came together to explore ways to

It also included discussions on human-resources management, along with visits to Saudi Aramco facilities.

Potential areas of collaboration include catalyst and process development related to hydrogen production from liquid fuels, nitrogen removal from heavy oil and olefin production. These areas will be further evaluated by both organizations with the intention to launch one collaborative project.

Alipio Pinto Jr.

Petrobras R&D Cent

Technological know-how is a strategic imperative for sustaining self-sufficiency in Brazilian oil production. Petrobras' Research and Development Center (Cenpes) Leopoldo Américo Miguez de Mello, pictured above is located on the Ilha do Fundão campus of the Federal University of Rio de Janeiro (UFRJ) and is responsible for anticipating and meeting the technological needs of all of Petrobras' operational areas.

Cenpes has 1,569 staff of which 350 members hold Master's degrees and 130 researchers have PhD qualifications. The center runs technological programs in Research and Development (R&D) and Basic Engineering (BE). The integration of the Center with the 2015 Strategic Plan's targets has resulted in a number of contributions to the Company's activities.

Among them are the basic projects for the P-34 and P-50 platforms, which are hallmarks of sustained self-sufficiency.

In 2005 Cenpes gave priority to three lines of production research: improving the production of heavy oil in an offshore environment; achieving technological advances in ultra-deep water areas; and minimizing the decline of mature onshore and offshore oil fields. In its efforts to improve production technology, one of Cenpes' objectives is to reduce costs for the Company.

ter

Horizontal wells are one of Cenpes' technological contributions for enhancing production as they increase the flow of oil out of offshore fields by up to a factor of five – thus making Petrobras' large projects economically feasible. The use of artificial oil lifting equipment, installed at a depth of 2,000 meters, has also been a decisive factor for the development of heavy oil production.

The continuity of the Deep Water Technological Program (Procap) is in line with the priorities that Cenpes has established. The objective of the program is to anticipate solutions for production in the Marlim Leste and Albacora Leste fields, in the next stages of Roncador and Marlim Sul fields, in the deep water blocks in the Santos and Espírito Santo Basins and in fields found in up to 3,000 meters of water depth.

In the fields of natural gas, thermoelectric generation and renewable energy sources, Cenpes participates in efforts to consolidate Petrobras as an integrated energy company.

Cenpes restructured its exploration R&D program in 2005. Previously the focus was on joint projects with Brazilian universities, now research has a central focus on the identification of exploration targets with a high degree of probability of an accumulation of oil and the detection of the exploration risks in ultra-deep waters and onshore basins. As a result, Cenpes' participation in solving Petrobras' specific challenges has grown.

Restructuring led to the creation of the Basin Modeling Program (Promob) and a Geophysics Department. Promob is aimed at running geological simulations designed to reduce exploration risks. The new department will intensify the development of computer applications, emphasizing 4D seismic imaging used to explore areas with complex geological compositions.

Beside reducing costs and optimizing Petrobras' investments, Cenpes' programs seek to achieve high levels of operational reliability, safety, excellence and the preservation of the environment. For the Company's downstream and refining activities, one of the main R&D programs strives to adjust Petrobras' refineries to the characteristics of heavy oil in view of the increased production of this type of oil in Brazil.

Technologies to be applied in processes, products and services are also under development by Cenpes, including the formulation of fuels with lower environmental impact. Another line of research is aimed at the development of solutions to increase the useful life of the Company's pipeline network and to reduce operating costs and transportation risks.

In the field of natural gas, thermoelectric power generation and renewable fuels, Cenpes is a part of Petrobras' overall efforts to consolidate itself as an integrated energy company. Besides working on innovations for expanding the use of gas, in order to boost gas consumption to 78 million m3/day in

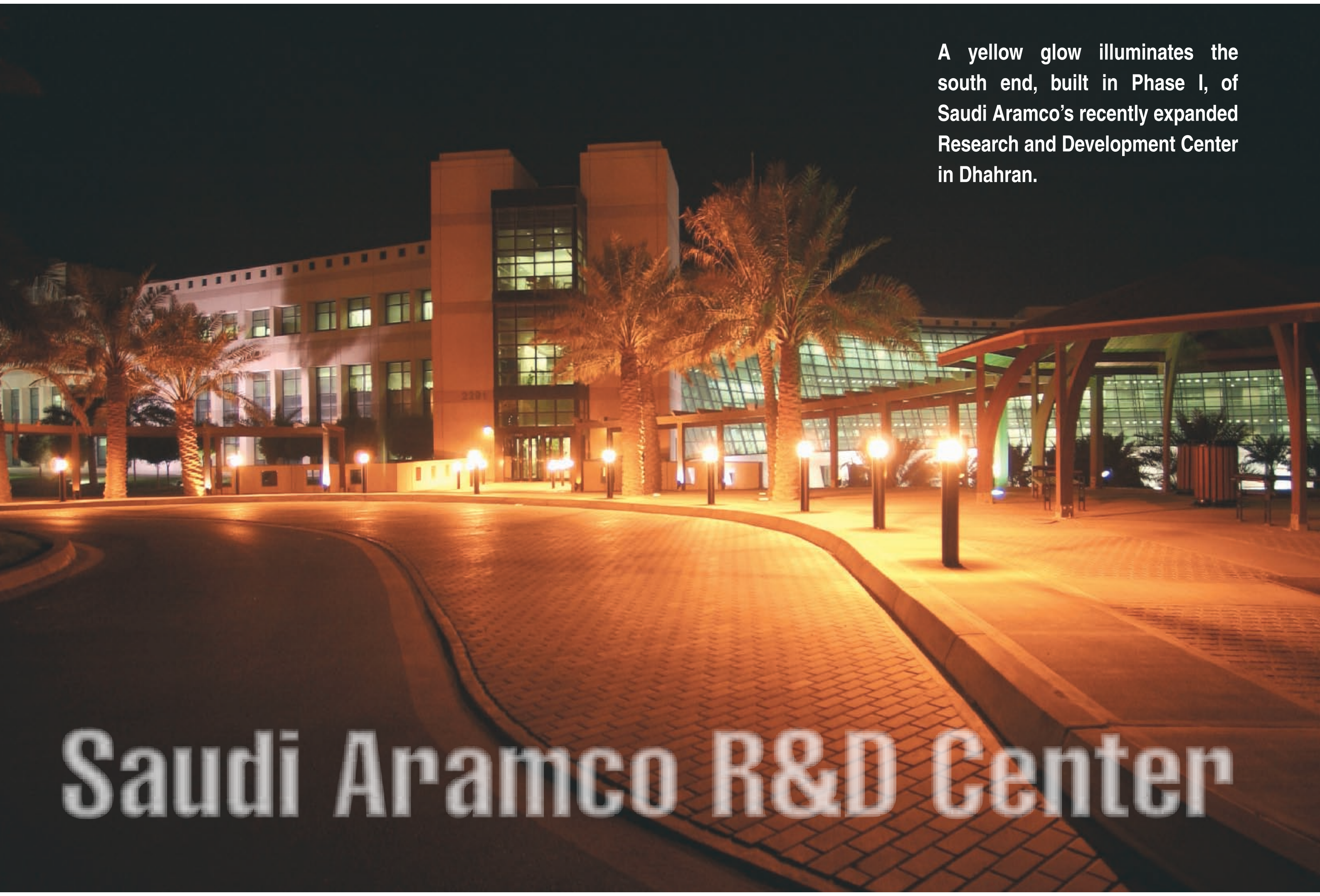
2010, Cenpes is developing programs to enable the Company's operations to achieve environmental excellence and sustainability and become eco-efficient. Furthermore, it seeks technologies that will make it possible to optimize the use of renewable sources of energy, satisfying the business targets of a number of segments within the Company.

Cenpes' basic engineering area participated in seven large projects in 2005, including natural gas production projects in the Santos Basin and heavy oil production projects in the Jubarte field in the Campos Basin.

In downstream activities, it was involved in projects at RPBC, Replan and Repar encompassing improvements in fuel quality, the reduction of polluting emissions and expansion of heavy oil refining operations. The Center also developed the new formulation of Podium gasoline in Argentina and continued its research for the production of biodiesel fuel.

Cenpes carried out a number of relationship activities with its stakeholders, strengthening the role of the Company as a technological leader and adding value to the brand. The Center launched a second edition of the Petrobras Technology Prize, created in 2004 to encourage the work of researchers and students in the field of oil and gas. For their innovative contributions to the Company's oil, gas and energy sectors, the authors of 27 projects that were selected during the first edition of the Prize received their awards in October.

Petrobras has initiated expansion of Cenpes in view of the new research demands that have emerged in fields such as the environment, gas and energy. New facilities, totaling 88.7 thousand m2, will be built on its land directly in front of the current buildings. The new building will contain effluent treatment and recycling stations and other technological resources, incorporated into the project according to the eco-efficiency concept.



A yellow glow illuminates the south end, built in Phase I, of Saudi Aramco's recently expanded Research and Development Center in Dhahran.

"Research & Development work is not new to us at Saudi Aramco. What's new about this project is that it provides a better work environment for the scientists of our company to help unleash their innovation and creativity," explained President and CEO Abdallah S. Jumah.

By Lori Olson White and Rick Snedeker

Abdallah S. Jumah said, "The nature and size of our oil fields and the huge magnitude of our operations as the largest integrated petroleum company in the world, as well as the operational challenges that we face during the execution of our activities, pose unique challenges and require solutions that cannot be brought in from anywhere in the world."

Muhsen F. Al-Ajmi, the Research and Development Center Department representative for the project, said, "Now we have a world-class facility which can accommodate the growing technical needs of our scientists in support of the strategic objectives and goals of the company. All those needs will be met in this facility for many years to come."

Seamlessly blending with the existing structure along a graceful curving wall of glass, the expansion includes extensive laboratory and high-bay facilities, an administration building, a high-pressure materials study building for autoclave operations, a chemical quality assurance/quality control (QA/QC) building and an expansion of the existing Chiller Plant. In addition, the Phase II project includes parking and landscaping.

The expanded center's 34,500 square meters of space contain pilot plants, workshops, offices, meeting rooms and 210 laboratory modules, which can be combined or separated.

This configuration accommodates 330 employees, 75 percent of whom are Saudis. Saudi Aramco's Engineering and Operations Services business line oversees the center.

The expansion project included new construction on seven buildings.

Buildings #2 and #3 each feature general laboratories with high bay areas accommodating the Research and Technology Division, Downstream Research and Development Division, Analytical Support Division, Material Science Research and Development Division and Services Support Division.

The three labs (including the one completed in Phase I) feature special air handling units custom designed to meet scientist-defined requirements and house the heart and soul of Saudi Aramco's quest for laboratory based innovation and invention. It is here that company scientists and technicians research solutions to the challenges unique to Saudi Arabia´s vast oil and gas fields as well as broader industry challenges.

A majority of the R&DC's employees go to work in these laboratory facilities.

Building #4 is the Administration Building and houses Research and Development Center management staff members and other key personnel within the department. Meeting space is also an important component of the building. Saudi Aramco has long recognized the value of teamwork in research, and R&DC scientists routinely collaborate with outside partners as well as home-grown experts in various disciplines within Saudi Aramco. It is here that many of those meetings take place.

Building #5, the High Pressure Materials Study Building, is a showcase facility for Saudi Aramco's commitment

It is here that company scientists and technicians research solutions to the challenges unique to Saudi Arabia´s vast oil and gas fields as well as broader industry challenges.

to ensuring the reliability and peak performance of company assets in a safe work-place environment. It is here that Saudi Aramco scientists conduct corrosion-related studies using so-called "sour gases" in a dynamic system. Every aspect of these critical studies was taken into consideration in the building's design and construction, from the need for control methods and condition monitoring to materials performance issues.

"This building was constructed with the highest standards of safety precautions," explained Al-Ajmi.

In addition to blast-proof chambers and facility-wide sensors that alert staff members should potentially hazardous conditions exist, the building's 24 autoclave chambers also allow scientists and technicians to make changes to the exacting testing conditions inside the autoclaves remotely.

Building #6 is the Chemical Quality Assurance Lab Building (CQAC). This was the first building completed in Phase II construction and works hand-in-hand with the gas testing lab built in Phase I, housing equipment and personnel to perform quality assurance studies for all oil field chemicals.

Samples of all chemicals are analyzed at the CQAC prior to being sent out to the fields to ensure that they meet Saudi Aramco's strict and exact specifications.

The Chiller Plant, the main construction of which was during Phase I, was expanded as part of Phase II construction, and features a custom-designed cooling tower which aids water circulation and heat absorption.

Saudi Aramco Senior Scientist Allan Fox has been involved with the R&DC project since 1997, working with other company scientists as well as engineers and contractors to create the company's newest scientific facility.

"This project used some new technology, including electronic review of the construction plans for some parts of the process," commented Fox. "Everything was very high-tech."

One area where high-tech was definitely put to the test was air quality.

"Having a facility of this size, which requires air that is 100 percent replaced, was a unique challenge," explained Fox. "We are dealing with a huge volume of air that cannot be recirculated due to possible chemical contamination."

"Because of this, we are constantly pulling new air in, cooling it and then sending it out," he added.

Due to this need for replaced air, the R&DC has a cooling system with a capacity three-times that of other systems in Dhahran.

Another high-tech solution incorporated into the R&DC was a sophisticated early warning system. More than 15,000 data points continually monitor variables including temperature, airflow, air rate and quality. Along with these sensors, heat and smoke detectors are also fed into a main computer within the facility to be monitored and acted upon.

Not only does the system ensure safety and improved reliability, but it also cuts down on unscheduled downtime, thus increasing facility-wide efficiency.

Construction of a new Technical Exchange Center was added to the expansion project's scope during 2004, and was completed in 2005.

With the Phase II expansion, the center is now even better equipped to meet its mandate: to help maintain Saudi Aramco's leading position in the hydrocarbons industry by using innovative applied research to develop cutting-edge technology and processes. Nearly a third of the company's United States-issued patents have been awarded to R&D Center scientists.

Saudi Aramco's sharp emphasis on research and development reflect the company's continuing and far-reaching commitment to meeting future global demands for energy, creating technology-based business ventures and identifying new revenue streams that promote the development of the local economy.

R&DC scientists, across myriad disciplines and often in collaboration with outside partners, are working hard to capture growth opportunities for hydrocarbons, protect future markets for crude oil and generate new businesses. The center is undertaking joint projects within the Kingdom and with regional research centers, is participating in joint industrial projects and is teaming up with international universities and research institutes.

Company scientists are busy seeking answers to a host of questions crucial to the industry: How can petroleum fuels burn cleaner and more efficiently? How can heavy crude oils yield lighter products? What are the best ways to combat corrosion? How can more oil and gas be produced from reservoirs?

In support of the company's exploration and production operations, the center's scientists develop laboratory based solutions, adapt transfer technologies and provide advanced technical services in petrophysics, hydrocarbon phase behavior, drilling fluids, oil-field cement, geochemistry, simulation and other areas. Researchers study the behavior of hydrocarbon reservoirs, perform geochemical rock assessments and look for ways to improve well productivity.

Ensuring reliability and peak performance of company assets is a critical goal, and the center's corrosion program is a cornerstone of this focus, through its investigation of control methods, condition monitoring and materials performance. Research activities also pursue development

Lab technician specialist Abdulrahman Al-Nowaishi (operating computer) and lab technician Marwan Al-Dossary perform a Nuclear Magnetic Resonance (NMR) analysis.

Company scientists are busy seeking answers
to a host of questions crucial to the industry:
How can petroleum fuels burn cleaner and more efficiently?
How can heavy crude oils yield lighter products?
What are the best ways to combat corrosion?
How can more oil and gas be produced from reservoirs?

of coatings, drilling-fluid polymers, and non-metallic and composite materials for use in operations areas.

The center also conducts vital environmental research, and its scientists are recognized as leading regional authorities on ground-water contamination and remediation, and seawater, marine life and soils management. Long-range eco-studies include waste-land reclamation and research into the Kingdom's water and ground resources. Also under study are the biogradation of hydrocarbon wastes and the development of micro-organism technology in oil-field and related industrial operations.

Now, and in the years to come, the center will continue its pioneering research and seek out new technologies to leverage oil and gas resources to enhance company profitability and expand the Kingdom's economy. Benefits will accrue to the Saudi people while helping to ensure the secure and responsible stewardship of the Kingdom's hydrocarbon resources for the world's burgeoning needs.

The center also pursues advances aligned with four long-term targets: sustaining oil's use in transportation, expanding oil's use as a feedstock in the chemicals industry, positioning oil to take advantage of power generation applications and exploring new markets for oil. To these ends, research topics include enhanced oil recovery and reservoir appraisal, next-generation clean-fuel formulations, and identification of new oil uses.

A decade ago, Saudi Aramco became one of the first oil companies to use scanning computerized tomography (SCT), a medical imaging technique, to evaluate oil-producing rocks. Today, the center analyzes thousands of feet of core samples for improved reservoir characterization and fluid flow visualization.

Other state-of-the-art analytical capabilities at the center are: powder x-ray diffraction to examine the physiochemical makeup of unknown solids, EDXRF spectrometry for scaling/mass spectrometry to study molecules, environmental scanning electron microscopy for very-high magnification imaging, and nuclear magnetic resonance spectroscopy for studying organic compounds.

During the past few years, the center completed water treatment and corrosion cost-reduction studies that identified significant savings through the use of new technologies, such as nano-filtration membranes, oil-based composite materials and new high-performance coatings. Also under way are investigations of next-generation petroleum fuel formulations and pioneering work on fuel chemistries suitable for emerging engine propulsion systems, plus a long-term focus on economical ways to convert oil to hydrogen for transportation applications, as well as stationary heat, power and electricity generation.

Another project seeks to increase olefin yields using a novel high-severity, fluid-cracking technology - a process that has been successfully piloted at Ras Tanura Refinery in collaboration with Japanese organizations.

The company continued working in the area of biotechnology to search for uses of micro-organisms

A decade ago, Saudi Aramco became one of the first oil companies to use scanning computerized tomography (SCT), a medical imaging technique, to evaluate oil-producing rocks. Today, the center analyzes thousands of feet of core samples for improved reservoir characterization and fluid flow visualization.

to process crude oil and to provide cost-effective environmental remediation solutions. New DNA sequencing and quicker micro-organism identification tools have allowed these organisms to be studied in much greater detail.

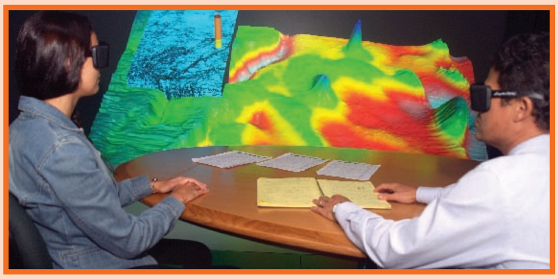
Current research projects also seek to utilize new sequestration technology to reduce industrial carbon emissions and to develop technological solutions that reduce emissions from automotive vehicles, including decarbonization of petroleum fuels and pre-combustion removal and recovery, as well as post-combustion remediation for internal combustion engines.

Specialized administrators manage the portfolio of intellectual assets and know-how that is emerging from the company's R&D work, investigating ways that in-house research and technology might be commercialized through the sale of proprietary solutions and licensing rights or the development of stand-alone technology businesses and partnerships with third parties. Technology-based business opportunities currently are being pursued in the manufacture of oleo-resinous paints and coatings, and oil-field performance additives, such as corrosion inhibitors and high-performance non-metallic materials.

Saudi Aramco's expanded R&D capability positions the company well to consolidate its role in the international petroleum industry today and to enhance and widen its capabilities and reliability in the future in meeting global energy needs — and growing the economy of the Kingdom.

Some of Saudi Aram

Seismic process patents: Our tradition of innovation in exploration continued in 2005 with the application for seismic process patents based on technology developed in-house. The patented technology involves the application of Anisotropic Magnetic Susceptibility (AMS) to microfracture characterization in the Unayzah reservoir. Two patents were submitted, one for the well-site application of the AMS technology to field-scale characterization of fractures, which will reduce the need for coring and imaging of reservoirs. The other patent submission deals with improving the quality of seismic pre-stack data.



In 2005, the company migrated the entire conventional seismic processing environment from a proprietary IBM supercomputer to more cost-effective Linux clusters with more than 600 terabytes (1TB equals 1 trillion bytes) of storage.

Smart well and Intelligent fields: Smart well systems and down-hole sensors are part of a larger strategy to develop Intelligent Fields, an approach that combines real-time monitoring and timely reactions to changing well and reservoir conditions to optimize production and reservoir management. A study conducted by a consultancy company, in conjunction with oil and gas companies, suggests that the Intelligent Field concept could significantly improve recovery factors, reduce capital expenditures, and reduce downtime and operations costs.

In 2005, in the Shaybah field, Saudi Aramco successfully installed the first Smart Well with a hydraulic down-hole flow control system in Saudi Arabia. The well, a maximum reservoir contact (MRC) multi-lateral type with a total reservoir contact of 5.4 mi/8.7 km, was provided with a smart well system to improve management of the reservoir and extend the life of the well. Future smart well systems are planned for the Shaybah field. The Haradh-III increment, brought onstream in early 2006, relies exclusively on multi-lateral MRC producing wells, and includes 15 wells with smart well systems.

Overall, the company completed 24 smart well installations in 2005 (versus two the year before), and 55 MRC wells, more than double the year before. These technologies are yielding significant results. In Haradh, a tri-lateral well with near-complete water cut was outfitted with a smart well system that controlled fluid entry into the motherbore, reducing the water cut to 24 percent and making the well a 6,000 bpd producer.

nco's RD&C Technological Achievements

In addition, we successfully developed two low-cost methods for converting existing single horizontal wells to multi-lateral wells complete with smart well systems. Both conversion techniques have delivered up to a five-fold increase in well Productivity Index (PI), while reducing the cost and number of rig days compared with drilling a new well.

Log-while-drilling (LWD): Once remaining oil is identified, horizontal wells (often of the multi-lateral type) are guided to the optimal location by using advance log-while-drilling (LWD) techniques. Well placement with LWD measurements is used in all drilling applications: onshore and offshore, for shallow oil or deep gas.

Under-balanced drilling: Equally important as the company's production wells are its water injection wells, which help maintain reservoir pressure and increase oil recovery rates. We have adapted the process of under-balanced drilling to eliminate formation damage and improve injectivity, thereby eliminating the need for post-drilling acid stimulation. This technique is, simply, drilling while the well is flowing, which allows formation fluids to flow into the wellbore, thus eliminating the formation damage mechanism. Other benefits include higher average initial injection rates, faster drilling times, and lower drilling and completion costs.

A total of 10 power water injectors were drilled under-balanced in the Hawiyah and South 'Uthmaniyah areas of the Ghawar field. The knowledge gained from drilling water injection wells under-balanced was applied to under-balanced drilling of oil producing wells at year's end.

Production equalizer technology: This technology allows a uniform production profile along the entire length of a horizontal well, increasing well production and improving reservoir sweep efficacy.

Multi-phase flow meters: In the offshore Safaniya and Zuluf fields, 39 multi-phase flow meters have been installed in wells to replace the test barges currently in use. The multi-phase flow meters are compact and can be operated remotely. In addition, unlike the barges, they are unaffected by weather conditions or water depth and allow for greater testing efficiency. In 2005, 65 of the meters were commissioned in Northern Area Oil Operations fields, with 13 more installed in 2006.

Geosteering Operations Center (GOC): To further exploit the technological gains of horizontal, multi-lateral and MRC wells, we opened our Geosteering Operations Center (GOC) in 2005. Located in the Exploration and Petroleum Engineering Center (EXPEC), teams of geologists and engineers remotely guide drilling activities in real time, around the clock, helping to ensure that every well is optimally situated.

Not only has Saudi Aramco become an industry leader in completing multi-lateral wells, it is a leader in actively evaluating and implementing new technologies for better planning and monitoring these complex wells. Techniques such as resistivity and carbon-oxygen reservoir saturation logs are used to evaluate water-flood efficiency and identify remaining oil in place.

Monitoring the performance of multi-lateral wells is a challenge, and one that has been met by extensive cooperation between us and our service companies. In one example, we are the first in the industry able to monitor water/oil/gas flow profiles in short radius horizontal wells.

3-D visualization centers: Saudi Aramco's 3-D visualization centers have undergone constant refinement since their inception, and in 2005, the centers were upgraded with the latest digital technology. New visualization techniques were developed for exploration and production, including seamless data integration between processing and interpretation, and super large 3-D seismic volume interpretation.

Operations Coordination Center (OCC): Tracking the movement of oil, gas and refined products from wellhead to tanker is enormously complex, but made easier and more efficient with the state-of-the-art data video wall in the company's Operations Coordination Center (OCC). The new video wall, a masterpiece of technology and the largest used in either the hydrocarbon or power industries, displays the company's crude oil, refined products, gas and NGL networks, terminals planning and scheduling, and electrical power distribution grid, all in real time.

The data display, 10 ft/3 m tall and more than 200 ft/61 m wide, facilitates the management of the entire system and helps optimize facility capacities and inventories to enhance revenues. The data wall allows quick detection of potential problems, and can also display live video from the field, geographical data, system drawings, satellite images, ship movements, and many other types of information.

Marcos Assayag receives Distinguished Achievement Award from OTC

By Petrobras Press Office

Engineer Marcos Assayag, General Basic Engineering Manager for the Petrobras Research & Development Center (Cenpes), participated in the evolution of deep and ultra-deep water oil production technology. He is now being acknowledged for driving technological solutions that influenced the offshore industry considerably. On May 1st, at the Offshore Technology Conference (OTC), Assayag was granted the Distinguished Achievement Award for Individuals.

In this interview, Assayag traces the history of Petrobras' research in deep and ultra-deep water exploration and production and talks about the importance of the awards the company has received at the OTC.

***Q: Brazil Oil & Gas** - The OTC awards are considered as the oil industry's "Oscars". They are granted to the companies and professionals who contributed the most to developing innovative technologies for this industrial segment. What does the Distinguished Achievement Award for Individuals 2007 represent to Petrobras and to you, named unanimously to receive it by the OTC's Awards Committee?*

A: Marcos Assayag - The Offshore Technology Conference has existed since 1969. Petrobras has participated in it since 1971. This is the most important oil and gas offshore exploration and production segment event. The 2006 edition, for example, brought nearly 60,000 people, from 31 countries, and 2,229 companies together. During the event, 291 technical papers were presented.

Every year, the OTC grants an award to the company that stands out the most in developing innovative technologies that could benefit the offshore industry. Another distinction is given to an individual who has contributed to developing these technologies. In 1992, Petrobras received recognition as a company for developing production technologies in the Marlim

Marcos Isaac Assayag, the general Basic Engineering manager for the Petrobras Research & Development Center (Cenpes), has worked at the company for 32 years and coordinated the following technology-development programs or oil exploration in deep and ultra-deep waters: Technological Qualification Program in Exploitation Systems for Deep Waters (PROCAP 1000); the Advanced Program for Technological Innovation and Development in Deep and Ultra-deep Waters (PROCAP 2000); and, until 2002, the Corporate Technological Development Program for Ultra-Deep Water Exploitation (Procap 3000).

field, and later in 2001, for developing the Roncador field. I was now acknowledged for driving Petrobras' technological developments as the coordinator of three technological programs, and for integrating the innovations, the outcome of a lot of teamwork, testing, applying them in oil fields, and divulging them. It was Petrobras' technical team's creative capacity, the trust of its managerial team, the company's motivation to explore oil and gas in increasingly deeper waters, and its talent to overcome challenges, to go beyond and to be a leader in offshore exploration and production that lead to my winning the Distinguished Achievement Award for Individuals. The award is granted individually, but I receive it as the crowning of a career and as representing all of those who worked at Petrobras, at Procap, in exploration and production, and in the Campos Basin Operation area. To the company, meanwhile, the award is yet another result of the investment it has always made in its human capital.

You can remember the days in which Brazil and Petrobras imported the technology they needed to refine oil, initially, and then to produce it.

Q: Brazil Oil & Gas - *What changed this frame of mind?*

A: Marcos Assayag - In the 1960s, when Petrobras put its refining park together using imported technology, it used to be cheap to import oil. Because of this, producing it wasn't seen as important for Brazil. That was why, when we found oil in the Guaricema offshore field, in 1968, and when we discovered oil in the Campos Basin, in Garoupa, in 1974, we repeated the strategy of importing technology to put the fields into production.

The 1973 and 1978 oil shocks, which skyrocketed oil prices, the unfavorable Brazilian trade balance, the discovery of the giant Albacora field in the Campos Basin, in 1984, at depths ranging from 250 to 2,000 meters, and the discovery of the Marlim field, in the same basin, in 1985, at depths ranging from 600 to 1,050, changed this scenario. We realized Petrobras had to boost its production, at the time some 171,485 barrels per day, and develop technologies to explore and produce oil in deep waters, something that simply didn't exist anywhere else in the world.

Q: Brazil Oil & Gas - *Was that when Procap' came around, kicking off the technological programs that would radically change Petrobras and Brazil's history in offshore exploration and production?*

A: Marcos Assayag - That's right. In 1986, Cenpes superintendent, José Paulo Silveira, created Petrobras' first deep water qualification program, the Procap. Later on it was called the Technological Qualification Program for Exploitation Systems for Deep Waters, the Procap 1000, as it involved exploring and producing oil at depths of 1,000 meters. The program encompassed the different existing fields of knowledge related to oil exploration and production, i.e. reservoirs, wells, submarine systems, lifting and flowing oil, pipelines, production units and anchoring systems, as well as being aimed at creating conditions to make production at the Albacora and Marlim fields viable. Engineer Frederico Araújo was chosen to be the first Procap coordinator, and, in a tenure that lasted through 1989, he was in charge of mapping likely technologies that could lead to production at the two fields and created a portfolio of 198 projects for this purpose. In August 1989, invited by the then new Cenpes superintendent, Guilherme Estrella, I was put in charge of coordinating the program, scheduled to end in 1991. I had the opportunity, and was honored to witness, consolidate, and divulge technologies developed by hundreds of Petrobras professionals for the Marlim field pre-pilot system that won Petrobras its first OTC award, in 1992.

Q: Brazil Oil & Gas - *Which technologies gave Petrobras its first OTC award?*

A: Marcos Assayag - The installation of the Marlim field's pre-pilot system, in March 1991, which was used to develop the field for a year and a half and consisted of an adapted drilling rig anchored at a depth of 625 meters to produce through two wells, one 721 meters and another 725 meters deep, in addition to a monofloat used to flow oil, leading Petrobras to create important innovations that allowed it to break world records and to win its first OTC award. Petrobras installed the first wet Christmas tree (set of valves that control oil and gas flow from the wells) without the assistance of divers and guiding cables. This wet Christmas tree was also installed at the greatest depth ever until then, i.e. 752 meters. We installed a flexible line at the same depth, another record, a CALM-type monofloat at 400 meters, and a floating production unit anchored at 625 meters. This had never been done before. We installed the world's biggest production platform in the Campos Basin, the P-18, a semi-submersible platform designed entirely by Petrobras, which was anchored at a depth of 910 meters. Furthermore, we completed the Marlim field at 1,027 meters depth, which was also an unprecedented move.

Q: Brazil Oil & Gas *- Did the success achieved by the first Procap encourage Petrobras to become even more daring and develop R & D technologies that would allow it to explore and produce oil and gas at even greater depths?*

A: Marcos Assayag - Not quite. A year went by before the project portfolio for the Procap 2000, Program for Advanced Technological Innovation and Development in Deep and Ultra-deep waters, was defined. The program, which would extend from 1993 to 1999, aimed at creating conditions for Petrobras to produce oil and gas in fields at depths between 1,000 and 2,000 meters and to incorporate new reserves located at these depths; to make the development of technologically innovative projects viable in ultra-deep waters; to optimize the use of the know-how and resources available in Brazil and abroad in order to cut development costs in deep waters; and to monitor deep water projects undertaken around the world. It was also through the Procap 2000 that we intensified the partnerships with universities, research centers, and vendors which we had already maintained during the first Procap. We then also established new ones.

Q: Brazil Oil & Gas *- A few of the technologies developed under the Procap 2000 won another OTC award for Petrobras in 2001. Could you mention a few of them?*

A: Marcos Assayag - The innovations that brought us the Distinguished Achievement Award in 2001 were developed for the Roncador field, located in the Campos Basin at depths ranging from 1,500 to 2,000 meters. For example, we developed new wet Christmas tree models, one of which was a horizontal one to be used at a depth of 2,000 meters, while the other a vertical one for use at 2,000 meters. We used the drillpipe riser for production. In an unprecedented move, we moored a semi-submersible platform at a depth of 1,360 meters using vertical load anchors (VLAs) in a taut-leg-type configuration, where Petrobras pioneered the use of polyester cables as a suitable material. We developed flexible flow lines and an electro-hydraulic umbilical cord to be used at 2,000 meters of depth. We used the Steel Catenary Riser, SCR, in the oil and gas export system, something that had never before been done in such deep waters. We used a gas lift manifold developed especially for use at a depth of 2,500 meters. Another highlight in the field's development was how fast this took place. The field was discovered in 1996 and went online in 1999 through the Pilot Production System, the FPSO Seillan.

Q: Brazil Oil & Gas *- Is this when Petrobras also contributed to qualifying professionals who could attend the new demand it created by using devices which hadn't existed until then?*

A: Marcos Assayag - That's right. Thanks to the partnerships it established, back then the Company qualified several vendors to produce equipment which didn't exist in the market before the advent of Roncador. This equipment could then be made available to other oil operators. This was in compliance with the OTC's Awards Committee's philosophy, as it always recommended that technological advancements be disseminated to the entire offshore industry.

Q: Brazil Oil & Gas *- You were in the Procap 3000, which focuses on developing technology to produce oil and gas in deep waters, from its beginning, in 2000, until October 2002, when you took over your current position. What are the most relevant highlights of this third technological program?*

A: Marcos Assayag - We have developed technology to explore and produce oil and gas at depths of 3,000 meters.

This technology has not been tested yet, though. We currently produce oil and gas at 1,886 meters and, until very recently, we didn't have fields at depths that were much greater than this. Only now, in the American portion of the Gulf of Mexico, will we have the chance to test this technology in the Cascade and Chinook fields, which have producer reservoirs at depths of 2,800 meters. We are the operators there and will be in charge of developing the production system project for these fields. Perhaps these developments will lead us to new records and new OTC awards? The anticipated system production is expected to kick-off in 2009.

Steering in the Right Dire

By Wajid Rasheed

Advances in rotary steering, logging technology and digitalization are bringing autonomous systems ever closer. Although systems capable of finding and accessing reservoirs on their own are still some years away, several types of rotary steerables exist today.

High-tech electronic solutions are sophisticated by nature, these systems are especially suited to costly complex designer wells. However, suppliers are offering a modular or combo approach which allows the degree of system sophistication to be determined by drilling engineers. This has already helped export some of the higher-end systems into certain intermediate cost shelf and onshore applications by tailoring certain BHA combos to well needs.

A different approach is being adopted by a number of smaller service providers who are developing simpler and more cost effective systems for the low rig cost market. The majority of these systems still rely upon electronics, but have fewer features such as lower DLS capability for instance and are aimed at 'simpler' lower cost wells. Simple or sophisticated - this much is clear - all systems generate cost savings and offer the potential to improve recovery from compartmentalized or horizontal reservoir sections.

But less clear is the criterion that makes one system 'better' than another. Reaching a consensus will always be contentious but an objective way of determining the best fit is to broadly 'match' rotary steerables with the varying dictates and expectations of deepwater, shelf or onshore drilling and completions. Drawing these variables together, Figure 1 (page 26) depicts deepwater, shelf and onshore sectors and matches technology appropriately.

Certainly, a rotary steerable system (RSS) must help reach the reservoir and optimize footage drilled within it but beyond this there are many reservoir and well dependent variables. For example, the Dogleg severity performance of a rotary steerable system should be matched with the complexity and number of targets involved. In complex designer wells, sophisticated systems shine. In less complex horizontal wells, simple systems suffice.

Similarly costs also drive system choice. It is well known that the tight economics of onshore or shelf assets cannot withstand high rig rates let alone expensive down-hole equipment. Here a match depends as much on reservoir needs (DLS required to reach optimal reservoirs) as it is driven by costs. Consider deepwater versus onshore trip costs. In the former an average round trip will cost $500,000. Yet, the same trip onshore hardly makes a tenth

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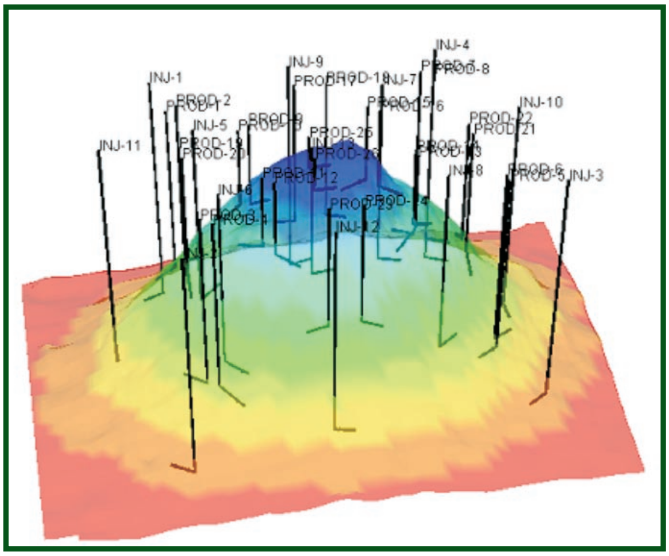


of this figure. In the first instance, it makes commercial sense to minimize trips. However, onshore it might make better commercial sense (depths and profile permitting) to induce trips by using conventional steering technology to line up sections and run in with rotary steerables where they have best effect.

Deepwater exploration frontiers are characterized by the highest rig rates in the industry and extreme exploration risk. This means contingency planning is a key component of deepwater operations. Relatively straightforward activities such as logistics can be rendered complex due to the remote and specialized nature of operations. Consequently, sophisticated rotary steerable systems that maximize efficiency and minimize risk, are not only desirable, they are necessary.

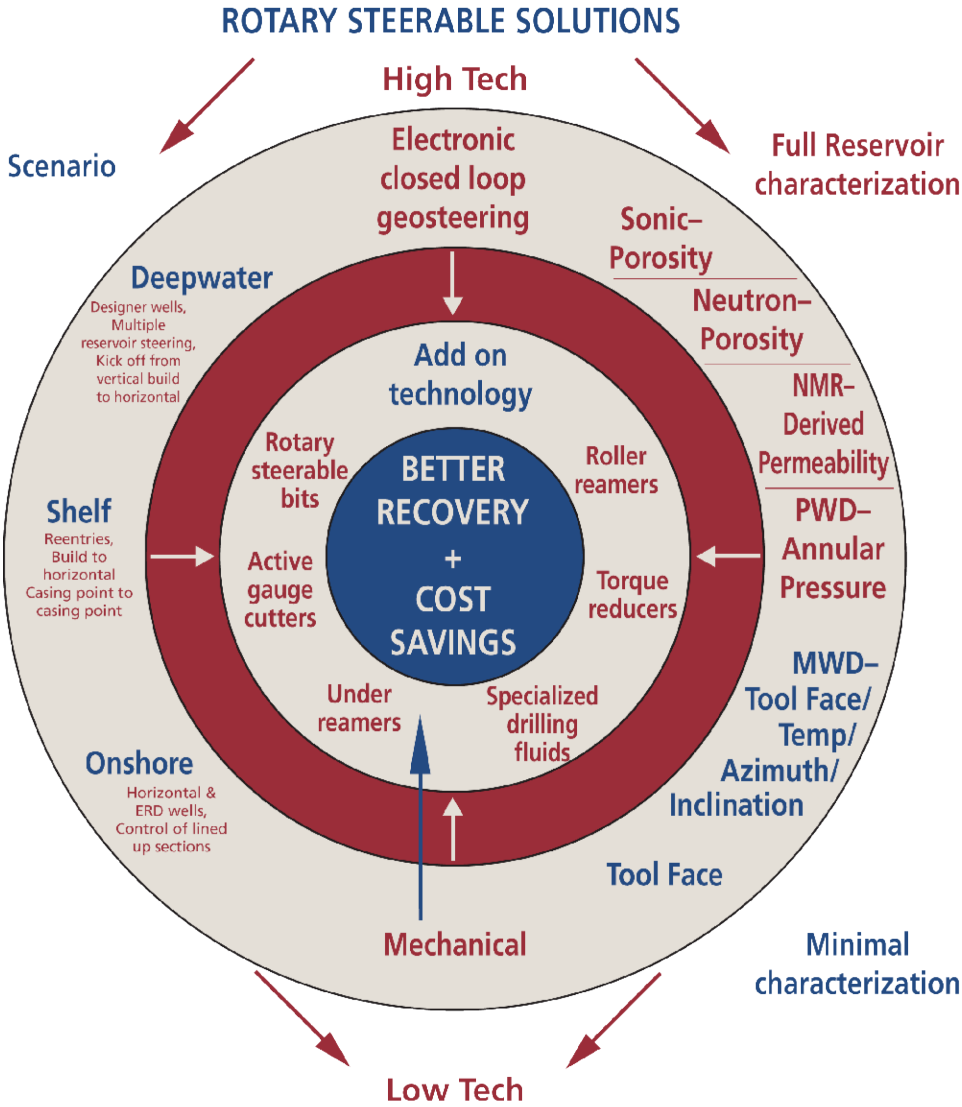
In these deepwater instances, a full range of reservoir characterization tools is also required. Sophisticated systems coupled with full logging capability reflect and meet deepwater frontier needs as offset data is often scarce and further asset development is dependent on data acquisition and interpretation. Therefore, the general rule is the more data acquisition and characterization the better. Data gathered 'while drilling' supplements the pre drill seismic package by increasing footage drilled in optimal reservoir zones.

Conversely, because mature assets are usually well characterized and offset data is plentiful, the same degree of data acquisition may be unnecessary. This makes mature or onshore fields ideal candidates for simpler rotary steerable tools. As we move down the characterization list, there is a diminished need for complete characterization. Intermediate or mature shelf assets may not require neutron magnetic resonance or sonic logging. While, in a marginal onshore context it is highly likely that a full logging while drilling suite becomes redundant. Little more than tool-face, azimuth, inclination, temperature and formation identification is required in this context. In exceptional onshore cases, the uncertainty associated with complex targets may require further logging but often a MWD plus Gamma system provides ample data.

In this way, technology can be pared down to bare essentials and costs lowered. What may have once been considered a marginal or mature field can be revisited with new economic parameters and perhaps be revitalized.

Add on Technology

Representing opportunities for reducing casing wear torque reducers can help overcome concerns of the effects of increased rotation on tubulars. Also roller



reamers aid BHA stabilization and reduce down-hole vibrations. While under-reamers, enable the diameter of production holes to be increased (especially important in deepwater scenarios where narrow pore pressure fracture gradients can jeopardize reservoir hole size) by allowing casing to be telescoped without sacrificing production. Also specialized drilling fluids exist to reduce torque and improve rotary drilling efficiency.

RSS Improve Drilling Effectiveness

RSS increase the effectiveness of drilling by improving reservoir exploitation. This comprises;

1. The certainty of precise inclination and azimuth control over the planned horizontal or directional section (the responsiveness of the system will be dependent on factors such as formation, the length of time a particular trend has been established and such like).

2. In cases an extension of the effective horizontal section drilled which would previously not have been possible using slide drilling. 1200' extensions as compared to offset have been documented in the US, North Sea and Middle East.

Increasing Drilling Efficiency

The argument for increasing drilling efficiency is based on the following attributes of the RSS;

1. The elimination of difficulties associated with oriented drilling.

2. Improved hole cleaning as Sanchez et al detail. Rotary mechanical agitation of cuttings beds and the orbital motion of the drillstring means that cuttings are less likely to form cuttings beds as they are continuously exposed, agitated and circulated out. It is recognised that this leads to better hole cleaning. This in turn reduces the time spent circulating at section TD to improve hole condition.

3. Synergy with PDC bits. Orienting with a PDC bit is recognized as being difficult; this can limit optimal bit

The various rotary steerable systems available on the market today offer a host of benefits, with simple and sophisticated systems complementing one another. Each can be selected to match the full spectrum of needs and scenarios ranging from deepwater exploration frontiers to intermediate applications to mature onshore assets. There aren't many technologies capable of revolutionizing drilling and completions. Or making a startling difference to field economics. Rotary steerables are one of them.

choice in certain formation types. PDC bits can be used with a Rotary Steerable System to optimise bit selection. This has led to reduced rock bit trips, better ROP's and improved directional response. It is worth considering that the majority of horizontal sections appear to be drilled with PDC bits.

4. Increased average ROP. Rotary drilling consistently yields higher ROP leading to a reduced time in drilling the section.

5. Fewer trips, Wisenbaker concludes this is highly attractive in an under-balanced drilling situation as each trip saved obviates the need to kill the well using expensive kill mud.

6. Improved Borehole Geometry - Fewer instantaneous changes in well-bore curvature means a smoother well bore. This means reduced hole tortuosity and an improved well profile. This is because rotary - build or drop - trends take time to break. Therefore, well-bore curvature is smoothed out over entire sections. Consequently, casing can be set more easily and there is reduced potential for work-overs, and interrupted production. This highlights the reduction in Casing or Tubular wear due to smoother wellbores. There is also a reduced requirement for reaming. This is because of fewer transition ledges and less potential for keyseating. Lower well-bore tortuosity reduces the need for reaming to decrease tortuosity or well-bore curvature. Kristiansen et al link consistent gauge hole with improved resistivity readings.

7. Reduced Torque & Drag - as quantified by Mims. Less need for BHA Torque Reduction devices. Less need for mechanical Drill-string torque reduction devices such as NRDPP or Subs. Less need for drilling fluid based torque reduction such as polymer beads or other additives.

8. Literature shows reduced potential for mechanical & differential sticking.

9. The absence of a motor allows improved bit hydraulics, annular velocity and higher flow rates.

10. Ability to withstand bottom hole temperatures higher than 150 degrees centigrade dependent on each RSS.

The various rotary steerable systems available on the market today offer a host of benefits, with simple and sophisticated systems complementing one another. Each can be selected to match the full spectrum of needs and scenarios ranging from deepwater exploration frontiers to intermediate applications to mature onshore assets. There aren't many technologies capable of revolutionizing drilling and completions. Or making a startling difference to field economics. Rotary steerables are one of them.

Mature Fields

By Majid Rasheed - International Editor

Case Study 1 – Petrobras (Steam, Microbes)

Mature fields create two major challenges for oil companies; a decline in production rates and the liability of platform or wellhead decommissioning oil and gas infrastructure. Increasingly oil companies have employed advanced Oil Recovery Programs and decommissioning strategies as their portfolio includes more mature fields.

During the 1980s and early 1990s, cost reduction became fashionable among the major oil companies and independents. EOR - Enhanced Oil Recovery - is commonly recognized as tertiary recovery and reservoir characterization methodology to increase recovery. Moreover, the scope of the research was broadened, to deal not only with tertiary recovery methods, but also with IOR - Improved Oil Recovery. This has been defined as any effort to accelerate and improve production rates while lowering costs in marginal fields using today's technology. This definition includes efforts such as water management, advanced well interventions and seismic for reservoir characterization and production monitoring.

During this time, oil companies targeted mature onshore and offshore oil fields worldwide not so much as an exercise in extracting maximum value of a scarce resource but rather to achieve the best return on sunk costs.

From 2000 onward rising oil prices prompted the drive for greater productivity. Contributing to this change of direction was the fact that many offshore fields were reaching or had reached maturity – Marlim, Gullfaks and Troll.

Tertiary oil recovery applications became internationally recognized and this area of production engineering covered most categories of crude oil with API grades varying from 13° to 41°. The industry adopted a broad ranging methodology, which enabled pilot testing to commercial/field applications, for steam injection, carbon dioxide injection and polymer flood.

All producing fields reach maturity one day, so the importance of mature field technology has accompanied the changing face of E&P. It is debatable as to exactly when a field becomes mature, but for our purposes we define field maturity as the point at which reservoir pressures decline to the point where they require secondary or tertiary recovery mechanisms such as gas lift or water injection to maintain production.

A major goal for oil companies is to improve the recovery factor for mature fields. A key method is to use imaging as a way of identifying remaining oil pools and improving the efficiency of water injection. This helps mitigate the problems associated with water production, such as souring and scaling, and thus decreases the lifting costs of old fields.

Water management

One of the main programs is water management. Besides the mitigation of problems, this program is concerned with the increase of the recovery factor, which is achieved with actions such as improving the areal sweep through correct evaluation of fracture direction under injection. Companies such as Petrobras are shifting from water injection to water re-injection, with the means of correctly managing water considering environmental needs. To ensure smooth transition from lab technology to field application, oil companies run pilot programs. For example, a pilot water re-injection program is currently being initiated in Marlim. Pargo and Carapeba have a similar pilot under way. Here old water (from the reservoir) is re-injected to maintain reservoir pressures.

To get an idea of the volumes manipulated, Petrobras handle an average water injection volume of 2 million barrels per day and half of it is produced.

The company also plans to construct a prototype system for 'raw' water injection. This system is placed over the seabed and is used to capture and filter water prior to injection. It has a good application on mature fields or fields where small platforms are often space limited.

A decade after the North Sea has had to come to terms with souring, other areas have had to implement Sour Gas and H_2S Management strategies. The HSE implications of water injection were well understood as injection had been started as early as 1988 in the Namorado field, Offshore Campos Basin. Souring was not a problem at the beginning as expected, but in the Marlim field, where water injection began in 1994, a H_2S breakthrough occurred in 2003. Injecting nitrate to mitigate the problem and to simulate the reservoir behavior of H_2S generation processes helps to define, for the fields under development, which strategy to adopt. The approach depends on the forecast of how much H_2S is involved and when it is being produced.

If none or very low H_2S volumes are expected – there is no need to act; if there are medium levels, metallurgical improvements may be selected; also sulphate removal for scaling treatment may mitigate some of the souring problems. If levels are high then nitrates must be injected. Two filed pilots, one re-injecting water and the other injecting seawater, both using nitrate, test the effectiveness of nitrate injection.

Oil companies commonly apply dual geoscience programs of Seismic for reservoir characterization and also 3D geological modeling. Seismic for reservoir characterisation is a main issue. An acquisition project started in 2005 with the objective of acquiring base 4-D timelapse data of the whole Marlim Complex (Marlim, Marlim Sul and Marlim Leste fields). This should give new insights which will direct an infill drilling program beginning in 2006 and extending to 2008. These infill wells will be drilled to produce remaining oil.

These technologies are being developed in conjunction with service and research companies, which are performing laboratory tests to help to determine the simulation parameters of H_2S generation in the reservoir.

Offshore operations have also been researching solutions to salt and scale problems. This can occur in perforations, tubings, subsurface and surface equipment. Remote operations have been used successfully to perform interventions such as well cleaning and squeezing of scale inhibitors into the formation. This has been done in the Marlim complex and also the Linguado field. Satellite wells using wet christmas trees are employed in all Brazilian deepwater fields, and remote handling avoids incurring high rig costs for intervention. The problems of metallurgy and any effects on subsea installations are carefully considered.

Geosciences

Oil companies commonly apply dual geoscience programs of Seismic for reservoir characterization and also 3D geological modeling. Seismic for reservoir characterisation is a main issue. An acquisition project started in 2005 with the objective of acquiring base 4-D timelapse data of the whole Marlim Complex (Marlim, Marlim Sul and Marlim Leste fields). This should give new insights which will direct an infill drilling program beginning in 2006 and extending to 2008. These infill wells will be drilled to produce remaining oil.

The Multi-component 3D/4C acquisition program for the Roncador field last year has now been processed to give definition of the internal heterogeneity of Roncador reservoirs – this is an area of approx. 30 sq km. This is a pilot project which was conducted in 1,700m sea water depth. Interpretation is made by geophysicists and geologists assisted by service companies. Petrobras has a '4D- room' where geologists and engineers can visualize geological phenomena.

As far as the 3D geological modeling project is concerned, Petrobras does not expect record breakthroughs; the idea is to provide state-of-the-art technology for non-conventional reservoirs, sealing faults, real time modeling modification and conventional logging. Also, the modeling plays a crucial part in understanding and reducing uncertainties in geological modelling. It considers how wrong images can be and whether estimated volumes maybe higher or lower, which can prove very useful.

Regarding the depositional heterogeneities for Brazilian reservoirs, this modeling reveals such things as the depositional features of turbidites and reservoir geometry. Knowledge of the depositional environment can help explain key reservoir characteristics such as gross size, volumes and channels.

Case Study 2 - BPTT & Petrobras (Seismic Application)

Reservoir Geophysics

Time lapse or 4D seismic accompanies the lifecycle of an oil and gas asset more earlier providing valuable seismic information on the asset as it matures. This is because as with all technology, seismic is subject to constant improvement. Therefore, seismic shot 20 or 10 years ago would have had limited 'vision' and likely only located 'shallow' reservoirs. Opportunities exist to find deeper reservoirs in mature fields, which were characterized by 2D (2 Dimensional) early less sophisticated seismic. This can be seen in the new frontiers or deep gas play, which is being explored in the Gulf of Mexico (both Mexican and US waters) and in the Columbus Basin.

This also has tremendous value in shaping decisions as to the peaking of production rates and decline curves. Usually, a cost-benefit analysis is conducted which measures costs and attributes the value gained. This exercise can be difficult as the value gained may often be indirect. 4D seismic is used mainly to better manage reservoir production across the lifecycle of a field. Due to the increasing number of brown fields worldwide applications of 4D seismic have increased substantially. However, as seismic is a recent technology there are relatively few processes available to evaluate it.

By virtue of its acreage in the Columbus Basin, BPTT owns various gas reservoirs in the Greater Cassia Complex, located offshore Trinidad and Tobago. Greater Cassia comprises brown and green field developments including Amherstia, Immortelle Parang, Kapok, Cannonball and Cassia. This required consideration of expensive 4D OBC (Ocean Bottom Cable) seismic acquisition options. Additional benefits from 4D seismic for monitoring dynamic reservoir performance could be foreseen with a permanent installation.

Here BPTT developed several research programs to refine decisions regarding which 4D acquisition option was the best solution.

In 2004, BPTT faced the challenge of valuing a number of seismic survey options over the Greater Cassia Complex in the Columbus basin, Trinidad. In Southern Greater Cassia several Tcf (Trillion Cubic feet) of gas reserves are located under shallow gas reservoirs, which often blur

seismic visualization. Development of these reserves is complicated by the presence of 27 stacked reservoirs with reserves trapped in over 100 separate segments. BPTT had to identify and value the style of survey required to improve seismic visualization over the southern half of the Complex affected by shallow gas imaging problems and value the benefits that 4D seismic could offer for reservoir management and future well placement. The main focus of this work is to present the process and the decision tree methodology used in the value assessment study as well as to present the main results from the study. The integration of these results with other elements helped support decisions for a seismic strategy for the 'Life of the Cassia Complex'.

In 2001, Petrobras embarked on a new reserve and reservoir management strategy integrating different specialists in asset teams within E&P business units.

Petrobras acquired its first time-lapse (4-D) seismic in Marlim field in 1997. In 1999, Petrobras started several 3-D, reservoir oriented seismic acquisition programs covering former 3-D surveys: South Marlim, Barracuda & Caratinga, Espadarte, Marimbá, and Pampo-Linguado fields in the Campos basin.

Common seismic processing techniques include pre-stack time migration and 3-D AVO analysis. Post-stack inversion is systematically used in reservoir characterization to map internal turbidite systems and to reduce the risk linked to reservoir distribution during appraisal and production. Visualization techniques are applied in three-dimensional and stereoscope views of exploration and development projects. The integrated reservoir studies are carried out in six main steps: 1) core

Petrobras has a long-term corporate technological program (PRAVAP) that outlines a strategy for advanced reservoir studies and geophysical characterization. The major focus of this strategy is on thin-bed reservoirs and seismic monitoring projects in order to survey water injection in deep-water reservoirs.

description, petrophysics, log interpretation and well log facies analysis; 2) reservoir geophysics interpretation; 3) stratigraphic high-resolution modeling; 4) geostatistical kriging and simulation; 5) reservoir flow simulation and, 6) reservoir technical-economic studies and decisions.

Petrophysics and reservoir geophysics

Some petrophysical properties used by engineers, geologists, and geophysicists to describe the reservoir can be related to acoustic and/or elastic impedance after seismic inversion. Seismic facies analysis can guide the stochastic simulation of petrophysical properties.

Petrobras staff at the rock physics laboratory have developed an analysis of acoustic and elastic properties of rock samples for reservoir studies.

The challenge for seismic contractors is to increase the quality and resolution of seismic data not only for exploration purposes but also for reservoir characterization. The new acquisition and seismic processing parameters oriented to reservoir characterization and monitoring will improve the seismic quality and resolution. With this new data set, reservoir geophysicists could refine the description of the reservoir external geometry, better understand internal heterogeneity of turbidite reservoirs and monitor the fluid flows.

Processing trends in reservoir geophysics

Historically, reservoir geophysicists have been using the same sequential process normally used in exploration. However, Petrobras has recently applied new techniques such as 3-D AVO, pre-stack time migration, and a new flowchart adapted to reservoir needs.

Interpretation trends in reservoir geophysics

For seismic interpretation, Petrobras' reserves and reservoirs team has been using:

1. interactive interpretation between geophysical and geological models;
2. seismic inversion and/or stochastic simulations and;
3. 3-D visualization and voxel-based automatic interpretation.

Such techniques allow a truly integrated approach in reservoir studies. For example, 3-D voxel pick interpretation of turbidites gives an immediate image of the shape and connectivity of acoustic events.

Technology in reservoir geophysics

As Petrobras reserves are located mainly in deep and ultra-deep waters, a permanent search is carried out for new technology solutions.

Petrobras has a long-term corporate technological program (PRAVAP) that outlines a strategy for advanced reservoir studies and geophysical characterization. The major focus of this strategy is on thin-bed reservoirs and seismic monitoring projects in order to survey water injection in deep-water reservoirs.

Case Study 3 – Troll (3D / Multilaterals)

As with almost all oil and gas fields, the Troll field is a complex of interrelated sub-fields and reservoirs. The Troll field is located in blocks 31/2 and 31/5 approximately 80 kilometres off the west coast of Norway at a sea depth of about 335 metres. The field consists of the gas producing Troll East sector, and Troll West, where recoverable oil lies under the gas cap. Troll's reserves are mainly gas (at one time it was considered to be a gas play only), but it also contains sizeable oil reserves and according to Hydro by first quarter 2006, Troll's total combined production surpassed one billion barrels of oil.

However, these reserves are distributed in hard-to-reach tight TVD horizontal corridors. Troll Oil consists of thin oil-bearing layers – just 4 to 26 metres thick – that lie beneath the huge Troll gas reservoir in the North Sea. Large volumes of oil are spread out through an area roughly 450 square kilometers.

Due to the thin and dispersed nature of these reservoirs; state-of-the-art drilling technology has been required. This includes the latest geosteering (rotary steerable systems in conjunction with logging and imaging to make real-time decisions) and especially the use of multilaterals to achieve maximized horizontal drainage.

Due to challenges such as sand and water separation; state-of-the-art completion and production technology has been required. This includes the latest subsea water separation systems and subsea sand separation to achieve maximum production.

Back in the late 1980s, many said that the Troll Oil field development would never be economically feasible, because its layers of oil were so thin and the price of oil was sitting at US$10 per barrel.

Achieving the impossible

It took the combined efforts and skills of personnel from geology and geophysics, reservoir management, production and process technologies to turn Troll from what was originally thought to be a gas field that initially had no commercially-producible oil to one of the largest-producing oil fields in the North Sea.

The success of this drilling and production experience led to the quest to produce the even thinner oil layers of the Troll West gas province – just 7 to 14 metres thick – with more subsea units and wells tied into a separate floating rig, Troll C.

Troll B Multilateral wells

Further development and greater recovery has been made possible by gradually extending the length of the horizontal sections and introducing multilateral wells – reducing costs and increasing the production area. Multilateral well technology has been essential in achieving effective reservoir drainage on Troll, and today, about one third of the more than 100 oil-producing wells currently operating in the Troll field are multilaterals. Five of these are three-branched, two are four-branched and a five-branch well was opened in 2004.

Through innovative horizontal drilling technology and using a floating production and storage vessel (FPSO) Hydro has shown that Troll West's thin oil layers could be developed and produced commercially. These oil layers were 22 to 27 metres thick, and production started in 1995 using the new floating production platform Troll B, connected to five manifold installations placed on the sea bed.

Troll West

The Troll West reservoirs are being drained by two platforms, Troll B and Troll C. These are both semi-submersible production units. Since it came on-stream, Troll B has been used to produce oil from the oil province and the southern part of the gas province. When it came on-stream in late 1999, Troll C started to deplete the Northern part of the gas province.

Production commenced on Troll B in September 1995, using eight pre-drilled wells in the oil province. Current production is 40,000-42,500m^3/day, from 21 wells, in the four oil province well groups known as D, E, F and G.

The platform has also brought wells from the south part of the gas province on-stream. Altogether, there are 24 subsea satellite oil producers tied back to the Troll B platform – 12 wells are in the H-cluster and 12 in well group 1.

Partners

Norsk Hydro Produksjon AS 30.6%

Petoro AS (Norwegian state) 56.0 %

A/S Norske Shell 8.1 %

Total E&P Norge AS 3.7 %

Norske Conoco Phillips AS 1.6 %

Recoverable reserves

Oil production started in 1995

Gas production started in 1996

Oil originally present: 1.46 billion barrels

Remaining 31-12-2004: 484 million barrels

NGL: 30.8 million tonnes

Condensate: 10 million barrels

Gas originally present: 46,525 billion cubic feet

Remaining 31-12-2004: 39,840 billion cubic feet

Oil Production (2005): approx 250,000 barrels per day

Gas Production (2005): 960 billion cubic feet per year

Water Control

Large volumes of water will be produced with the oil from the thinner zones of Troll West. Separating this water from the oil before it reaches the surface can increase oil processing efficiency.

Long term recovery targets

Hydro's recovery target for Troll is an ambitious total of 1.9 billion barrels of oil from the Troll field previously considered unproducible – a recovery rate of 45 percent.

The remaining oil reserves of the gas province will be developed by 58 horizontal wells. Plans envisage that 14 of these will be drilled with two branches. These 58 wells will be arranged in ten well groups, each normally containing two templates. Between two and four wells will be drilled from each template. Three of these well groups – J, K and L, which will contain a total of 18 wells – will also be tied back to Troll B and use the spare tie-in capacity on the platform.

Troll C

The remaining seven well groups will be routed to a new Troll C platform, which is located in the Northern part of the gas province. There will be no drilling facilities on Troll C. In early 1998, a second rig started pre-drilling wells in the gas province. Production from this part of the field commenced in late 1999. The drilling programme was planned for completion in the year 2002, but with the possibility of extending beyond this date in order to discover the potential for improved oil recovery.

Troll C has an oil-production capacity of 30,000m³/d, a water production capacity of 40,000m³/day, a liquid production capacity of 60,000m³/d and associated gas production capacity of 9 million m³/d. It has a total displacement of 52,750t and can accommodate 70 people.

Troll's oil-bearing layers were so thin that many experts doubted that the field was viable. But horizontally-drilled multilateral wells have changed all that – and now the latest well is pumping oil from some of the most challenging fields anywhere in the world.

The well has been drilled into the challenging sand strata on Troll, the so-called M-sand. Until now, oil production has come from sand formations with better production qualities, the so-called C-sand. In the M-sand formations there are several hundred million barrels of oil, and although recovery rates may turn out to be lower than the rest of the field, this formation can nevertheless be a valuable boost to oil production.

Prospects for increased recovery

Among those people who are most interested in seeing how the well produces, is the head of petroleum technology in Troll Mature Fields, Tor Madsen.

"This is a really exciting well. The risk is higher than usual, since the production qualities are lower than elsewhere on the field. But if the well can maintain production over a longer period, it will be able to increase recovery considerably," says Madsen.

"The Troll wells that were drilled nearly ten years ago are still producing well, but there are reserves around the wells that are not being recovered. For the first time we have therefore converted an existing well into a multilateral well," he explained.

The new multilateral consists of one complete branch and two twigs. The procedure has nearly doubled production from the old well, from more than 3000 barrels of oil per day to over 5500 barrels.

Multilateral wells have been a minor revolution in the way oil is recovered from the Troll reservoirs. By drilling wells with several branches it's possible to cover larger areas, and recover oil from more places than one single branch is capable of.

The Troll B platform is the control centre for the multilateral wells.

Drilling hydraulics de for long horizontal se

The development of deepwater heavy oil fields at PETROBRAS requires, as technical and economical criteria, the drilling and installation of sand control devices in long horizontal sections. Eventually, large diameter wells will also be required. Among the operational issues related to hydraulics, the following are critical: ECD restrictions, drilled cuttings transport and gravel pack displacement (if this is the adopted sand control technique).

This article discusses important aspects of hydraulics design for drilling long horizontal section wells, including: the conceptual strategies for extending hydraulic limits while drilling, the role of cuttings loading on downhole pressures, the combined role of rheology and flow rates on minimizing ECDs and the role of drill string design on pumping pressures.

R.A. Gandelman, T.J.L. Oliveira, A.T.A. Waldmann, A.F.L. Aragao, R.A.F. Leal and A.L. Martins - Petrobras

Introduction

The new scenario for offshore development in Brazil includes heavy oil fields in deepwaters. Vicente et al. presents a detailed study on wellbore geometry optimization for deepwater heavy oil reservoirs, using a fully implicit, 3D numerical model coupling reservoir and horizontal well flow dynamics. The study suggests that 1000m to 2000m horizontal section wells are required to economically exploit the reservoir. Besides that, due to the non-consolidated formations found, sand control techniques are required in Campos Basin, offshore Brazil. Therefore, the development of deepwater heavy oil fields requires, as technical and economical criteria, the drilling and installation of sand control techniques in 2 km long horizontal sections. Eventually, large diameter wells will be also required.

Oil exploitation in deepwater environments presents several particularities concerning well design. Due to the low sediment coverage, rock formations frequently present low competency and, consequently, a narrow window between pore pressure and frac pressure.

sign
ction offshore wells

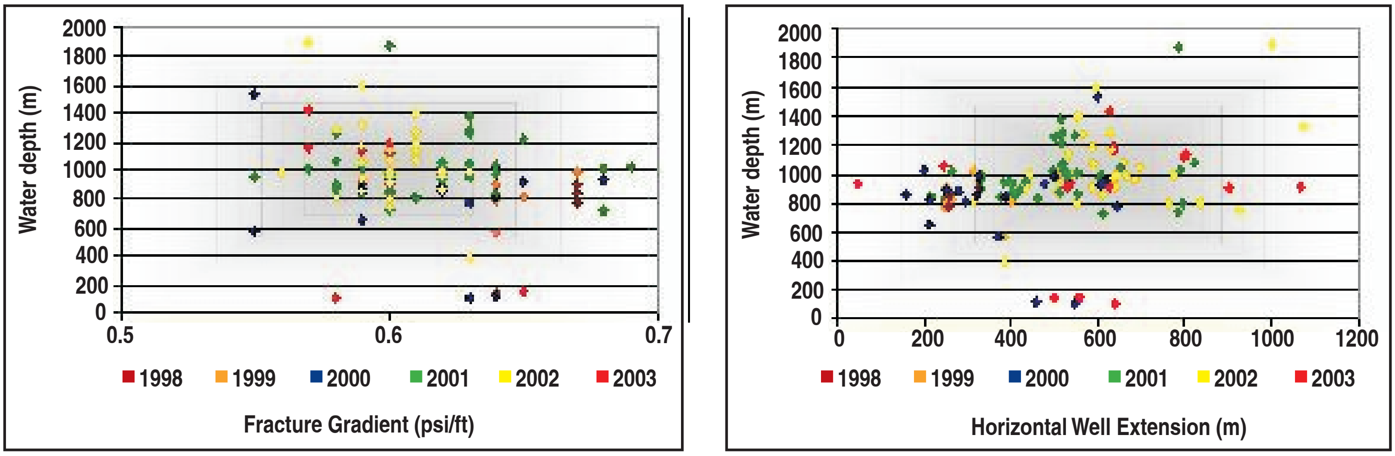


Fig. 1 - Typical fracture gradients and horizontal well extensions in Brazil offshore operations

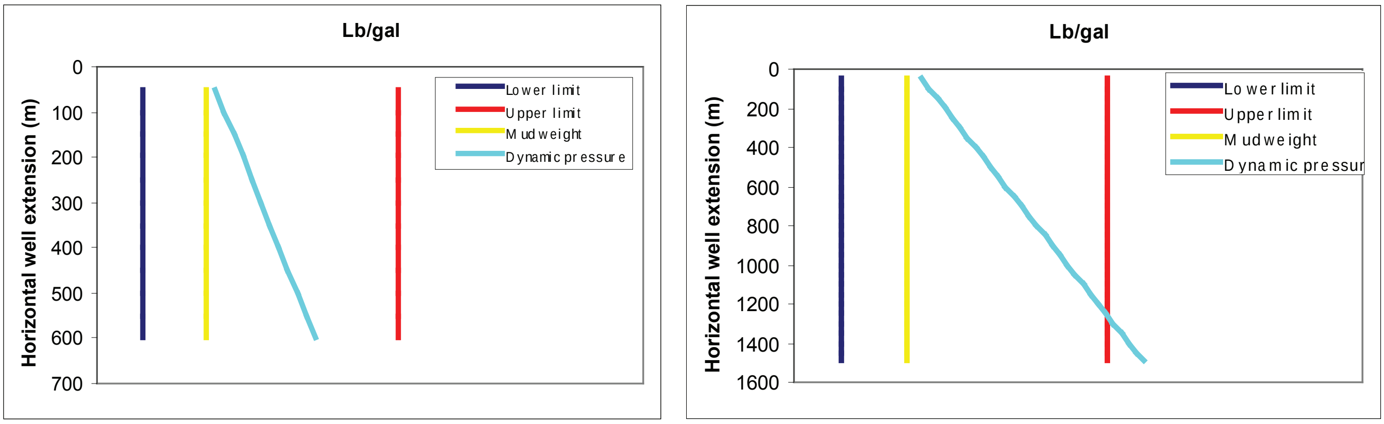
The main focus of this article is how to determine feasible flow rate requirements for each of the hydraulics impacted operations which fit to frac gradient restrictions and to establish ways to evaluate and minimize fluid invasion and consequent formation damage to the reservoir.

The long horizontal section well in narrow operational windows

Fig. 1 shows a plot of fracture gradient versus water depth for 119 horizontal wells drilled in Campos Basin between 1998 and September 2003 and a plot of the horizontal well extension as a function of the water depth for the same group of wells. This group represents the totality of horizontal wells completed with gravel pack and consists of 95% of the total horizontal wells drilled in Campos Basin in this period. Fracture gradients range from 0.56 to 0.68 psi/ft while water depths range from 100 to 1900m. Maximum extensions reached 1100m.

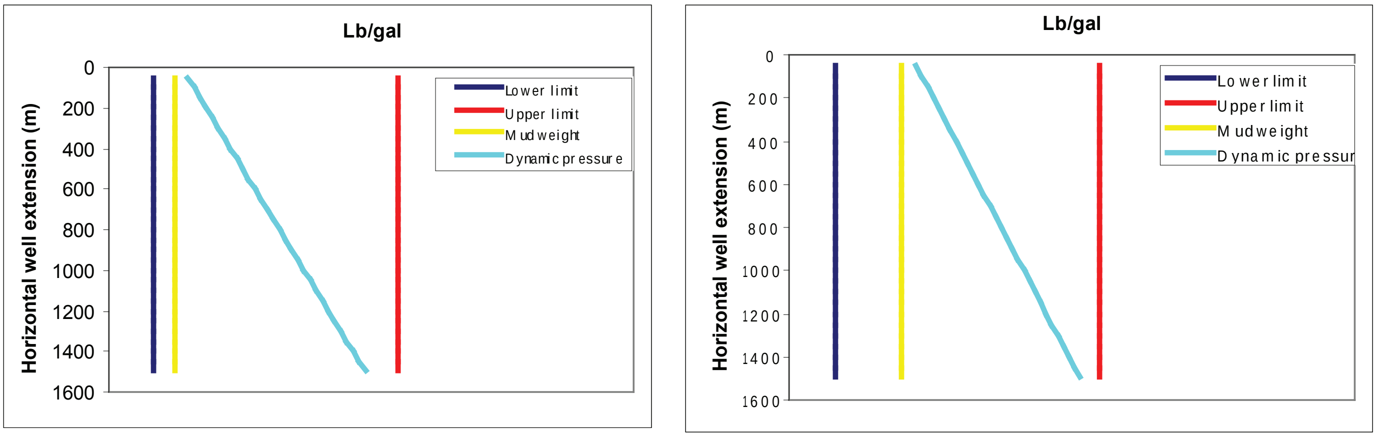
As previously detailed, the future scenario will bring greater challenges: 2000 m horizontal wells at similar frac gradients. Besides, exploratory drilling water depth records reached 2700 m, indicating that future development in these areas may include even lower frac gradients.

Due to the critical operational window, all the effort should be spent in accurately defining the operational window. Real time pore pressure determination proper collapse and fracture modelling are the driving tools to achieve a reliable operational window. Fig. 2 shows a schematics of an operational window which fits conventional horizontal wells and does not fit long horizontal wells due to the expressive friction losses. In both cases, a conventional 200 psi overbalance is provided by the fluid weight. Fig. 3 proposes two different conceptual alternatives to drill the long horizontal section: reducing the hydrostatic overbalance to a near balance (or even an under balance, refs) and reducing friction losses.



Conventional Horizontal Well **Long Horizontal Well**

Fig.2 – The Hydraulic Challenge of drilling a long horizontal section well in a narrow operational window



Reducing Mud Weight **Reducing Friction Losses**

Fig.3 – Conceptual alternatives for extending the hydraulic limits

Understanding the impact of cuttings loading in downhole pressures

Hole cleaning is the issue which defines flow rate requirements to drill the horizontal section. For high angle wells, hole cleaning dynamics is governed by the tendency of the solids to either deposit or not at the lower portion of the annulus, forming a cuttings bed. Normally, for the group of wells presented in the previous item, it was possible to drill the reservoir phase using flow rates which guaranteed total bed removal.

The same does not happen in the previous phases of these wells, where the drilling of larger diameter bores at high inclinations normally results in a cuttings bed formation. In several situations, the build up phase is drilled with 16 or 17 ½ in bits, reaching inclinations as high as 82 degrees (Almeida et al.). In these cases, hole cleaning is obviously sub-optimal and drilling occurs in the presence of an expressive cuttings bed (Fig.4).

Among the several methods available to evaluate cuttings transport (Gavignet et al. Nguyen et al. among several authors), the model proposed by Martins et al. is extensively used for design, follow-up and troubleshooting purposes in most PETROBRAS operations. Experience dictated that it is possible to drill safely with bed heights around 15% of the well diameter, according to the adopted model.

The two phase flow approach proposed to compute bed heights results in an unusual friction loss X flow rate relationship: There is an optimum flow rate where friction losses are minimized in the presence of cuttings, as illustrated by Fig. 5. The decreasing behaviour of

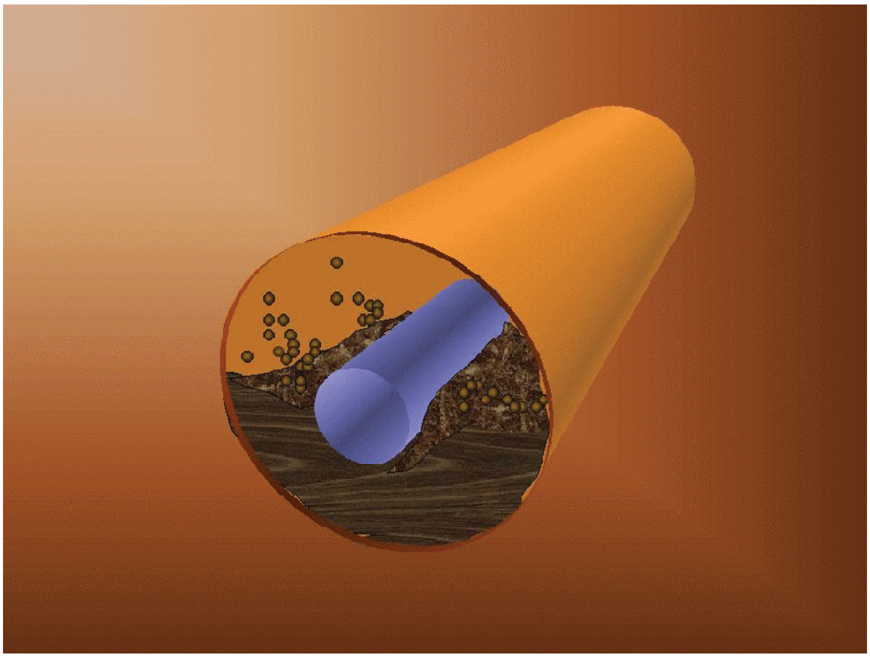


Fig 4 – Cuttings bed formation in large diameter inclined wells

friction losses with the increase of flow rate in the left portion of the figure is explained by the gradual removal of the cuttings bed and, consequently, the increase of the area open to flow. When the bed is almost removed,

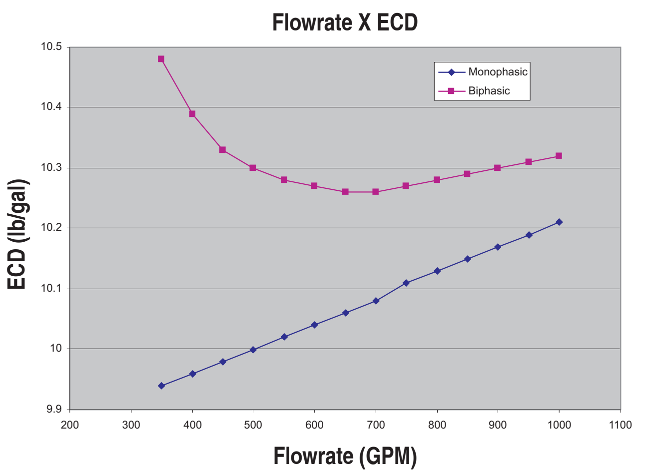


Fig. 5 – The Unusual annular pressure drop behaviour in the presence of a cuttings bed

a behaviour of increasing friction loss with increasing flow rate is obtained. Whether this minimum will occur or not inside the operational range will depend on each specific well design.

Unlike the 119 wells drilled, the new scenario will contemplate longer horizontal sections. In this case, annular friction losses may play a relevant role on down hole pressures, limiting flow rates. In suboptimal cleaning conditions, flow is restricted to the area above the cuttings bed which generates extra friction losses. Besides, the cuttings load traveling through the annulus directly affects hydrostatic and friction loss terms. The model proposed by Martins et al. considers annular friction losses as a function of the stratification level and a mixture density concept to account for the effect of solids in the hydrostatic and friction loss terms in suspended flows, as follows:

$$ECD = \rho_{mix} + \frac{\Delta P_{annular}}{gh} \qquad (1)$$

$$\rho_{mix} = \rho_s C_s + \rho_f \cdot (1 - C_s) \qquad (2)$$

$$\Delta P_{annular} = \sum_{i}^{n} \frac{2 f \rho_{mix} v^2 L}{D_h} \qquad (3)$$

Solids accumulation in the riser, due to the low annular velocity, can directly impact hydrostatics and, consequently downhole ECDs. Fig. 6 illustrates the impact of fluid flow rate on downhole ECD for different water depths when 9.5 in long horizontal sections are drilled at high ROPs. The increase of ECD at low flow rates, especially at the deepwater wells, are a reflex of poor solids transport in the riser. Viscous pills pumped by the booster line, as well as extra pumping are recommended. Fig.7 shows the effect of cuttings loading on ECD for a typical offshore horizontal well.

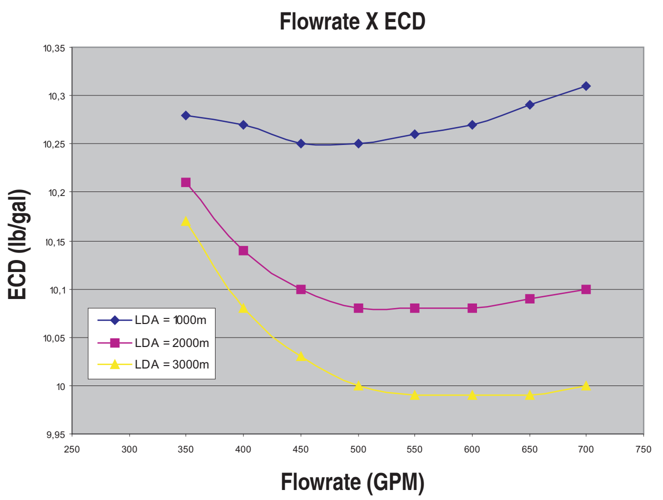


Fig. 6 – The Impact of solids accumulation in the riser annulus on downhole ECDs.

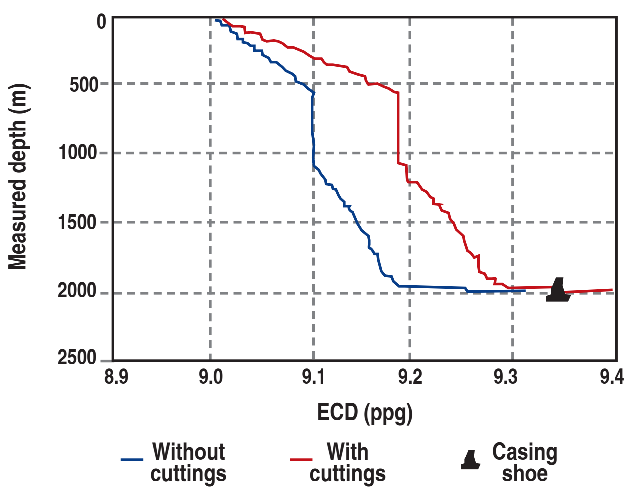


Fig. 7 – Influence of the presence of solids on ECD in a typical deepwater well

Designing optimum flow rates and fluid rheology

Several articles have presented a discussion on the impact of operational parameters on hole cleaning (Azar and Sanchez, among others), most of them based on flow loop experiments. In practice, however, several of the variables, such as inclination, eccentricity, mud weight, and drillpipe rotation are governed by directional drilling and reservoir requirements. Fluid rheology and flow rate play important roles on both hole cleaning and friction losses and their optimum design is dedicated to the hydraulic challenges. A discussion follows:

The role of rheology on downhole pressure is complex and affects several events including hole cleaning, friction losses and pressure peaks after circulation stops. In dynamic conditions, highly pseudoplastic behavior is desired: high viscosities at low shear rates prevents cuttings sedimentation while low viscosities at high shear rates enhances cuttings bed re-suspension and minimizes friction losses. Fig. 8 shows a typical rheogram for a drilling fluid, highlighting the desired properties at each shear rate and the limitations of the oilfield viscometer data.

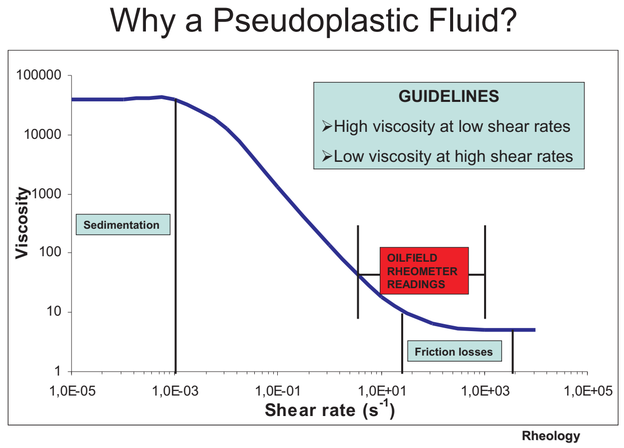


Fig. 8 –Typical Rheogram of a drilling fluid

Fig. 9 and 10 illustrate the effects of fluid rheology on cuttings concentration and ECDs for a typical deepwater well. Fann V35A readings decrease from fluid A to fluid C.

Gelation phenomena occur when pump stops and are desirable aspects of a drilling fluid since it would help keep drilled solids in suspension. Gelation tendencies are

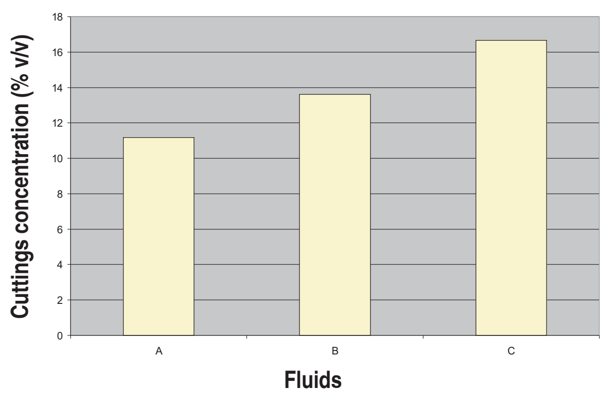


Fig. 9 – Effect of fluid rheology on cuttings concentration

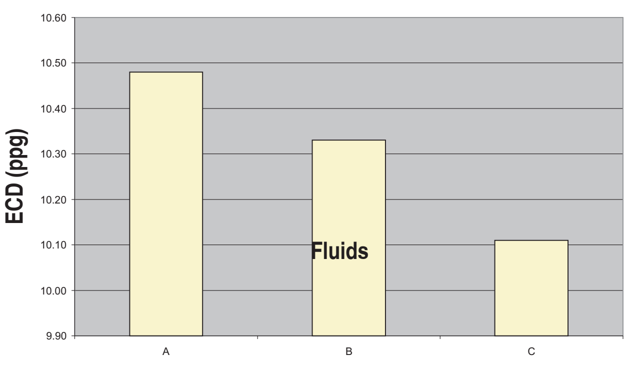


Fig. 10 – Effect of fluid rheology on ECD

normally higher at low temperatures typical of deepwater risers. Severe gelation can, however, induce pressure peaks when the pump starts again. Such peaks may have detrimental effects when frac pressure is reached.

Important parameters governing gelation are temperature, pumps off time, drillpipe rotation and start up flow rate. The smaller the pump off time, smaller will be the time available for heat exchange and to form a gelled structure. Once a gelled structure is formed, the energy required to break it and restart movement will be greater (Bjørkevoll et al) and consequently, a pressure peak will be generated.

Rotating the pipe before starting the pump may help break the gelled structures. Starting the pump with increasing steps of flow rate can also help gradual breaking of gelled structures and minimize the risks of pressure peaks.

Table 1 shows three representative examples of pressure peaks due to gelation in a typical offshore well. The magnitude of the pressure peaks are expressed in density (ECD) units.

In event A, the pump was turned on (400 GPM) and off several times to help gel breaking. Pipe rotation was 130 RPM. Similar peaks were obtained. Finally, a similar peak was also obtained when the pump was started at 800 GPM to resume drilling. Even with the adopted

Table 1 – pressure peaks after pump start up

Event	Δρ (ppg)	Flow rate (GPM)	Speed rotation (RPM)	Pump off time (min)
A	0.15	400	130	40
B	0.35	700	0	430
C	0.1	250	120-140	200

Table 2 – Yield stresses values evaluated by different equipment

Rheological model	Fluids	Oilfield viscometer	Low shear rate Rheometer
Bingham	Synthetic based fluid	8.41 Pa	8.523 Pa
	Polymeric based fluid	9.40 Pa	4.300 Pa
Herschel-Bulkley	Synthetic based fluid	5.99 Pa	7.669 Pa
	Polymeric based fluid	6.13 Pa	2.961 Pa

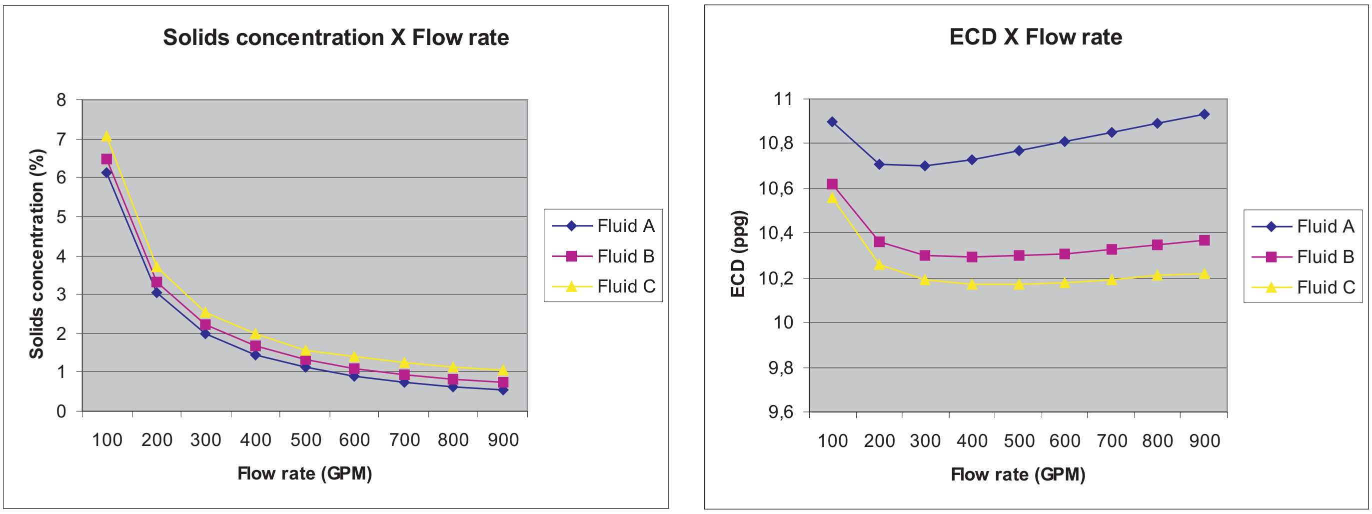


Fig. 11 – The effect of Rheology and flow rate on hole cleaning and ECD

procedure, 0.15 ppg pressure peaks were observed. Possibly higher peaks would be experimented if no rotation was adopted and the pump was started directly at 800 GPM. Event B resulted in the largest pressure peak among the considered database. Fig. 13 illustrates the values, besides no rotation speed and the less careful process adopted on the pump start up: in this case the pump was started and turned off immediately and then restarted at 700 GPM. ECD values decrease continuously with time reflecting gel breaking and fluid thinning due to heat exchange processes.

Gelling properties of drilling fluids are desirable for solids suspension while pumps are off. On the other hand, they can generate dangerous pressure peaks when the pump is restarted, especially in the low temperatures typical of deepwater scenarios.

Evaluating rheological properties, which represent the fluid behavior in deepwater wells, is a critical topic. Dynamic viscosities obtained by Fann VG 35 readings represent properly the friction loss processes but fail to capture sedimentation phenomena. Low shear rate viscosity measurements are available for lab use but the reliability of their results is not achieved in floating vessels. Table 2 highlights the difference in evaluating yield stresses using the conventional field device and lab low shear rheometers for two typical fluids used in deepwater applications (Monteiro et al.). Although gelation tendencies can be estimated in the Fann V35A, important additional information can be gathered with different rheological experiments including small amplitude oscillatory tests and creep-recovery experiments, among others. In all cases evaluating properties at the low seafloor temperatures is a must.

Optimizing rheology and flow rates for minimum ECD and sufficient hole cleaning is not a direct process. More viscous fluids transport solids properly but enhance friction losses. The optimum design frequently considers intermediate value rheologies pumped at the maximum flow rate allowed by the operational window, as highlighted in Fig. 11. Fann V35A readings decrease from fluid A to fluid C.

Of course, admitting bed formation in a long horizontal section requires special care on drilling and hole cleaning practices. Controlled ROPs, sweeps and dedicated wiper trips are mandatory practices in such situations. Besides, real time monitoring of hole cleaning conditions are very useful tools to anticipate problems. Pressure While Drilling – PWD (Mallary et al.) and Cuttings Flow Metering – CFM (Naegel et al. and Tohnhauser et al.) are highly recommended.

Minimizing pumping pressures

While drilling long horizontal section wells, flow rate design for sufficient hole cleaning may lead to excessive pumping pressure. Even if modern pumping systems are available, pressures should be minimized to avoid operational risk and equipment wear.

Besides rheological optimization, discussed in the previous item, drillstring design also plays a major role on pumping pressures. Friction losses inside the drillstring often accounts for 90% of the total parasite losses and can be reduced by selecting larger ID drillpipes and proper tool joints.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The Automation of Oil and Gas Processes

The automation of industrial processes depends very much on the type of process involved. Manufacturing processes require speed and reduced execution time, while processes involving food and drink require 'recipes' to be strictly followed and as with pharmaceutical processes, automation must ensure that contamination does not take place. In the implementation and operation of automated chemical, petrochemical, oil and gas processes the most important factors are safety and operational reliability.

Today's automated processes in the oil and gas industry are characterized by product and service solutions which offer the following:

• A high degree of integration and communication;

• Reliability and Safety

• Ease of maintenance

• Support of professionals with skills in electrical, instrumentation and control engineering and the supervision of processes to make sure that operational needs are met.

Companies that wish to offer automated services certainly need to have dedicated teams that not only supply products and services but that are also as highly specialized as possible within automation niche technologies so that the proposed products and services are correctly furnished.

Within the Oil and Gas industry, Health, Safety and Environment issues are the most important factor in implementing automative processes and understanding the many different product configurations. Selected processes should guarantee personal safety, installation safety and production as well as respect the needs of environmental protection.

We can see that a priority exists in guaranteeing operations as well as other needs of safety and reliability, but the biggest challenge in the automation sector is to have the highest levels of safety and reliability designed into the process from implementation and operation.

Automated processes should be configured to have personal, installation and safety environmental considered as joint priorities.

Basic project engineering services define the regulations and the type of automated process that will meet operational needs considering the safety and reliability of Oil and Gas automated processes.

These requirements mean that three key process areas must be considered for the production process:

• Software;

• Hardware;

• Humanware: the individual responsible for the construction, operation and maintenance of the automated process.

The applications and products are undoubtedly important and define the type of solution which takes into consideration numerous technical factors such as:

- Redundant Configuration
- Dual Redundant Network
- Remote data access
- Transmission Integrity
- Telemetry
- Local Network
- Field Network
- Data Transfer rate
- Ease of programming
- Memory capacity
- The task burden on the control room operators

The configuration of Oil and Gas automated processes will always lead to certain redundant features related to failure tolerance, fail-safe mechanisms, higher specification communication, supervision and integration.

Detailed engineering services and applications are without doubt a life-cycle element that should not end with acceptance testing of the implemented solution but that should guarantee performance and continuing improvement of the project during its full life-cycle.

Ultimately, the process engineer should work hand in hand with the automation engineer in order to obtain the maximum productivity in a safe and trustworthy manner.

This partnership should be based on following:

- The relevant regulatory standards.
- The basic engineering requirements.
- The requirements of process engineering.
- The correct implementation of products verified by a commissioning process.

Following the tasks above the project is guaranteed as risk is minimized in the implementation and a consistent automation solution is provided.

During the project life cycle – which includes the development of an oil and gas field – the needs of process engineering highlight the contribution of process engineering in improving the implementation and providing new techniques promoting the continuous improvement of operational efficiency.

However, the degree of project success ie conception, development, system launch and the delivery of an industrial automation solution are closely linked with the level of synergy that exists between the automation engineer and the process engineer responsible for the operation of the industrial plant.

This relationship can be defined in a single word: 'Constructability'. That is to say the ability to construct and deliver a quality service on time and in accordance with client demands.

We at Unicontrol are very pleased to participate in this edition of Brazil Oil and Gas as we wish to note our standing in the industry independent of contract clauses, costs and challenges. Unicontrol's philosophy includes the training of our highly specialized team of professionals, a profound dialogue with our clients, professionalism in dealing with project specifications and meeting the requirements of our solutions offered to the oil and gas automation market.

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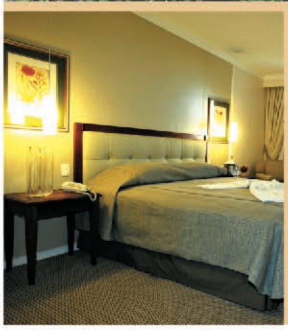


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