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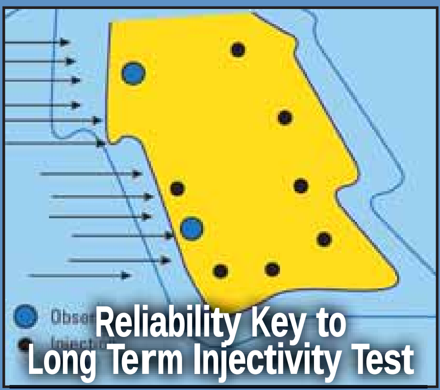
Reliability Key to Long Term Injectivity Test


Petrobras Strategic Plan


New Pre-Salt Discovery in Campos Basin


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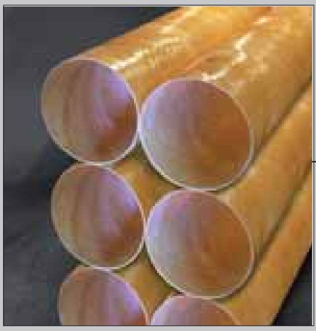

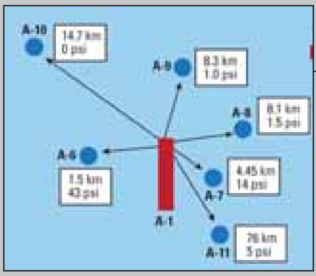

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New Pre-Salt Discovery in Campos Basin

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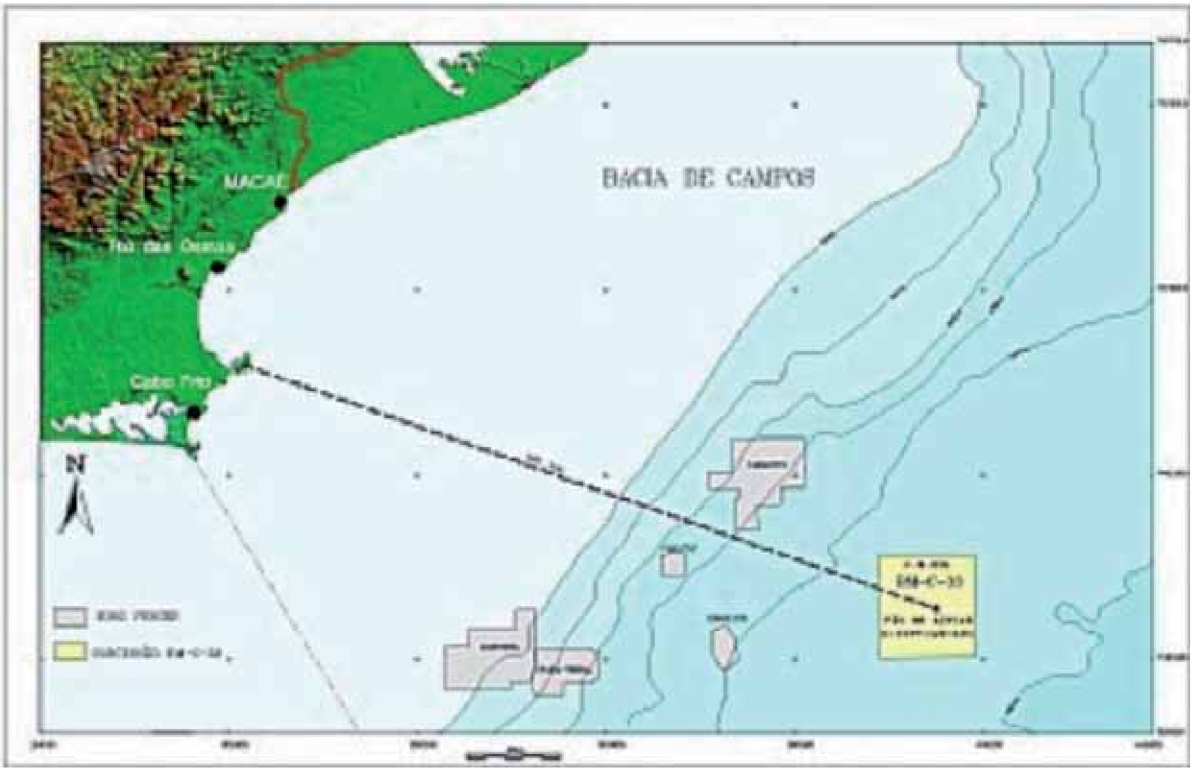

Petrobras News Agency.

Petrobras announces the discovery of a new hydrocarbon accumulation in the pre-salt layer, in the southern area of the Campos Basin, off the coast of Rio de Janeiro. The discovery took place during drilling of the prospect unofficially known as Pão de Açúcar, in block BM-C-33. The discovery well is located at a water depth of 2,800 meters and is 195 kilometers off the coast of the state of Rio de Janeiro.

Repsol-Sinopec Brasil is the operator of the area with a 35% stake, in partnership with Statoil (35%) and Petrobras (30%).

The drilled well detected a total hydrocarbon column with 480 meters in thickness, with approximately 350 meters of reservoirs. The formation test indicated a production of 5,000 barrels of oil and 807,000 cubic meters of gas per day.

The consortium will conduct additional analyses in the area to confirm the extension and volume of the discovery, using data obtained from this well. The Pão de Açúcar well confirms the huge potential of block BM-C-33, where the Seat and Gávea prospects were discovered.

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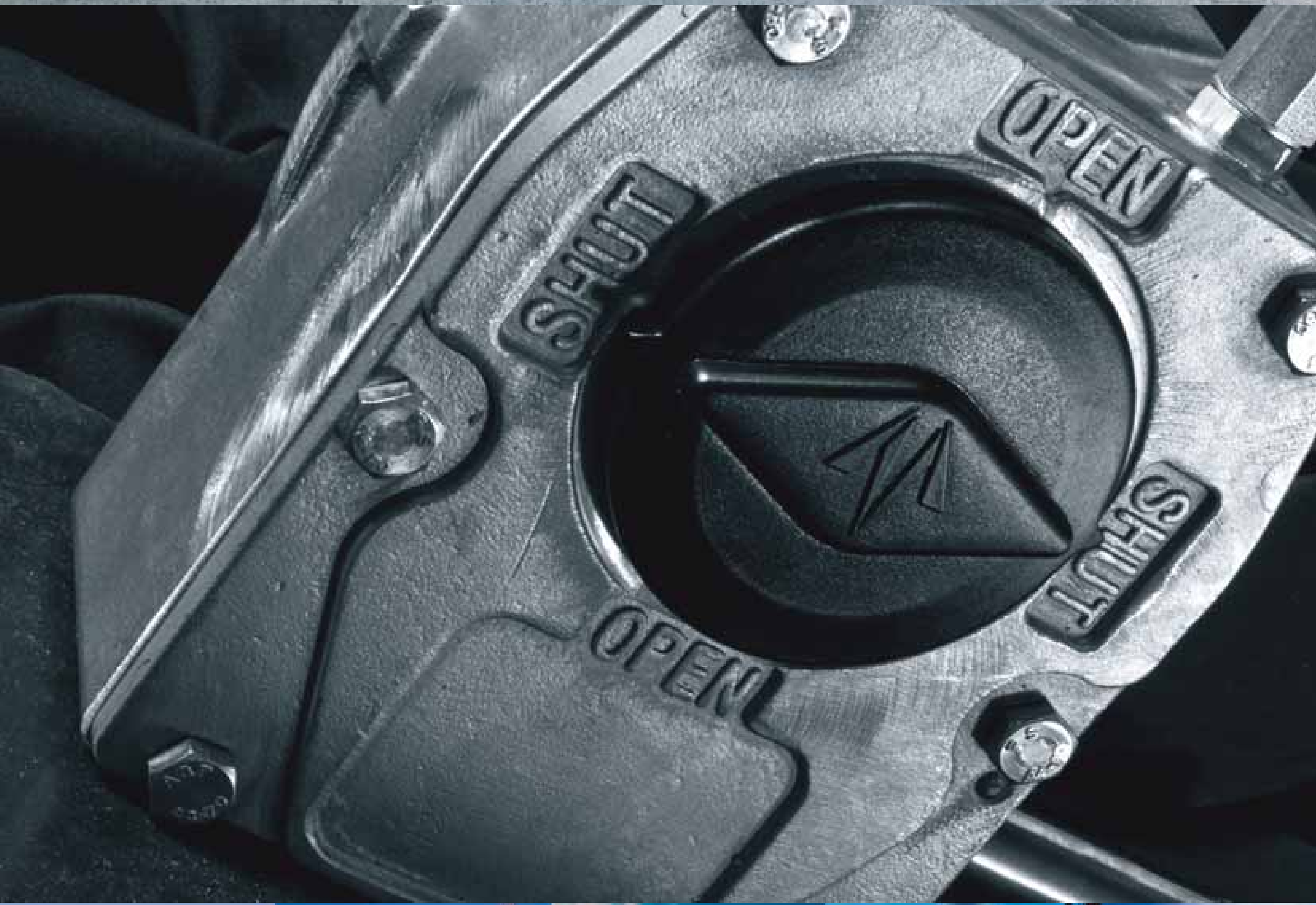

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Corrosion Control Planning is Critical For Extending Life of Injection Wells

By Oscar Zapata, Engineering Manager, Duoline® Technologies.

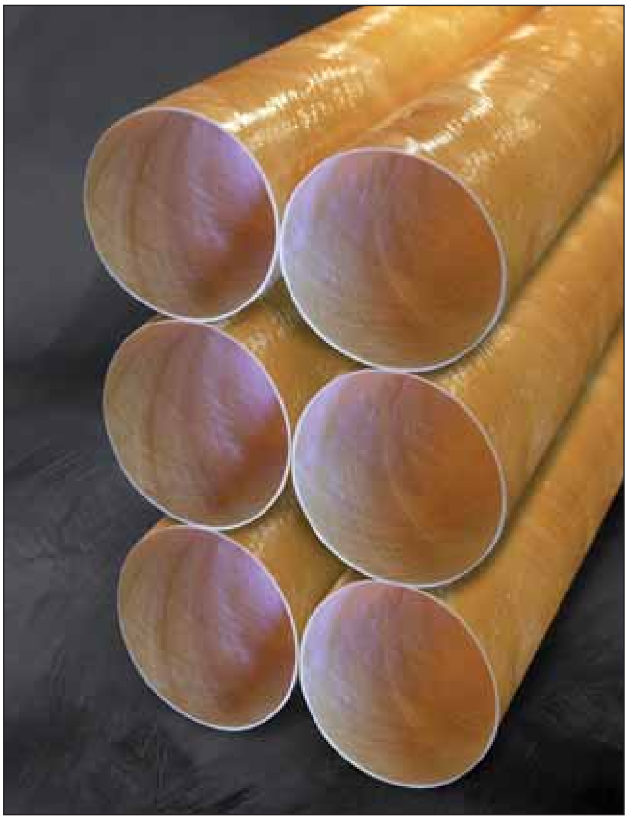
As early as 1875, oil operators concluded that water injection could be used as an effective method for driving oil from within a formation. Other means of recovery have since then been developed. After years of trial and error, however, it has become apparent that water – either from natural geothermal or surface sources – is the most economical means of secondary recovery.

Sources For Injector Water:

The following sources of water are typically used for recovery of oil:

• Produced water: often used as an injection fluid. Produced water is a term used in the oil industry to describe water produced along with oil and gas. If the volumes of water being produced are not sufficient, additional "make-up" water must be provided. Mixing waters from different sources exacerbates the risk of corrosion.
• Seawater: the most convenient source for offshore production facilities. At times it may be pumped onshore for use in land fields.
• Aquifer water: from water-bearing formations other than the oil reservoir. Aquifer water has the advantage of purity where available.

Failure of a pipeline.


Duoline liners.

Problems Associated With Water For Injector Wells:

Despite the many benefits gained by using water, the quality of the injection water is continuously blamed for failures in the water injection system from the seawater intake facilities to the well bore.

Corrosive damage to the pipe from these waters results in significant costs to the E&P industry. For example: at times repairing wells has resulted in prolonged work-overs and eventual shutdown injection facilities; and can also affect a company's capability to push water into the reservoir to maintain its pressure.

Types of Corrosion Found in Injector Systems

The type of corrosion caused by reservoir water depends on the chemical composition of that fluid. These waters can be composed of a wide range of chemicals including strongly acidic waters containing sulphur and halogen acids which actively corrode most common alloys.

The velocity of injection fluid can also affect the rate of corrosion. As velocity increases, the transport of oxygen to the surface becomes faster, so the corrosion rate increases. Injection velocity can also cause scouring of corrosion products, thus removing the protective film.


Installing Duoline liners.

The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities.

Oxygen: The Greatest Concern

The gas that causes real corrosive consequence in this environment is oxygen. Although the solubility of oxygen decreases to a minimum as the temperature rises near 100°C, it is very important to minimize CO_2 contact with water. CO_2 corrosion attack increases with increase in oxygen concentration, the organic acid by-product is referred to as carbonic acid (H_2CO_3).

Carbon-Dioxide Corrosion: Still of Concern

Carbon dioxide in water can contribute to corrosion of steel, but at equal concentrations it is much less corrosive than oxygen. The rate and amount of corrosion caused by dissolved carbon dioxide is dependent on the oxygen content, the salts dissolved in the water, temperatures and fluid velocities. Water containing both dissolved oxygen and carbon dioxide is more corrosive to steel than water that contains only an equal concentration of one of these gases.

Hydrogen Sulfide Corrosion

Hydrogen sulfide is often present in oil field production brines that are subsequently disposed by well injection. This practice has resulted in instances of severe corrosion in injection tubing, especially when brines become contaminated with oxygen.

Corrosion rate also increases in water containing hydrogen sulfide and is influenced by the presence of dissolved salts and carbon dioxide.

Chlorides: Causes Stress Corrosion Cracking

The presence of chlorides in the well fluids attack pipe material and is influenced greatly by the temperature, chloride concentration and stresses in the metal. The presence of oxygen and low pH value accelerates the attack on the metal.

Elemental Sulfur Corrosion:

Elemental sulfur will be present in some reservoir fluids and is a very strong oxidant. It mixes with the water in the fluid and forms sulfuric acid and reacts to form sulfides. Corrosion due to elemental sulfur increases with temperature.

Methods To Combat Corrosion in Oil & Gas industry

Fighting corrosion continues to be a nightmare for many oil field staff. While there are many methods to prevent corrosion these are the three most common:

• Change the material of construction for the specific application.

• Reduce the intensity of corrosive attack by modifications in corrosive media.
• Create a barrier layer between the material and media to avoid the direct contact.

Corrosion Prevention: The Reality

Mitigating the effects of corrosion found in injection wells harsh environment can reduce expenses, lost revenue, and risks to safety and the environment. Yet, before making any changes to prevent corrosion remember there may be additional cost. It is more important to think in terms of life cycle costing, which may show a longer equipment life and lower maintenance cost in spite of high initial cost. Before any change is made a detailed study of the injector process and operating conditions should to be carried out by a professional corrosion engineer.

Fiberglass Liners Proveto Provide One Effective Solution in Harsh Environments

There are effective ways to prevent corrosion in order to extend the life of the tubular. Operators have used a variety of coatings and liners including internal fiberglass lining.

Many major oil companies have found that fiberglass liners offer an ideal solution to prevent damage to pipe. This is due to fiberglass being strong and light weight for easy moving, as well as the material's effectiveness in providing a long-term corrosion prevention solution.

The company offers a variety of liner selections that match material performance to specific application needs. The unique process of inserting a rigid plastic or GRE composite (Glass Reinforced Epoxy) liner sleeve inside the pipe eliminates the “holiday” potential.

Duoline® fiberglass liners are cured by applying internal heat to a hollow mandrel. This ensures that encapsulated air pockets do not occur on the liner's bodywall – a major differentiation from liners produced using a thermal cure cycle which cures the outer diameter first and increases the potential for product failure by encapsulating air pockets on the liner's bodywall. This benefit, combined with the high hoop strength of the company's GRE liners provides the most resilient available lining system for high-pressure gas service or water systems with high CO_2 or H_2S content.

Another important consideration for any corrosion resistant piping system is protection of the connection area, which is the strength of the process.

Most coated tubing corrosion failures originate in the connection area and this is why the technology employs a reinforced elastomeric corrosion barrier ring (CBR), which is compressed between the liners in the connection make-up process. This compressed CBR is held in place by the liner, and prevents passing fluids from causing the all-too-common coupling failure. The technology also employs a metal wire reinforced nitrile elastomer ring for API connections and a Teflon glass filled corrosion barrier ring for premium gas tight connections.

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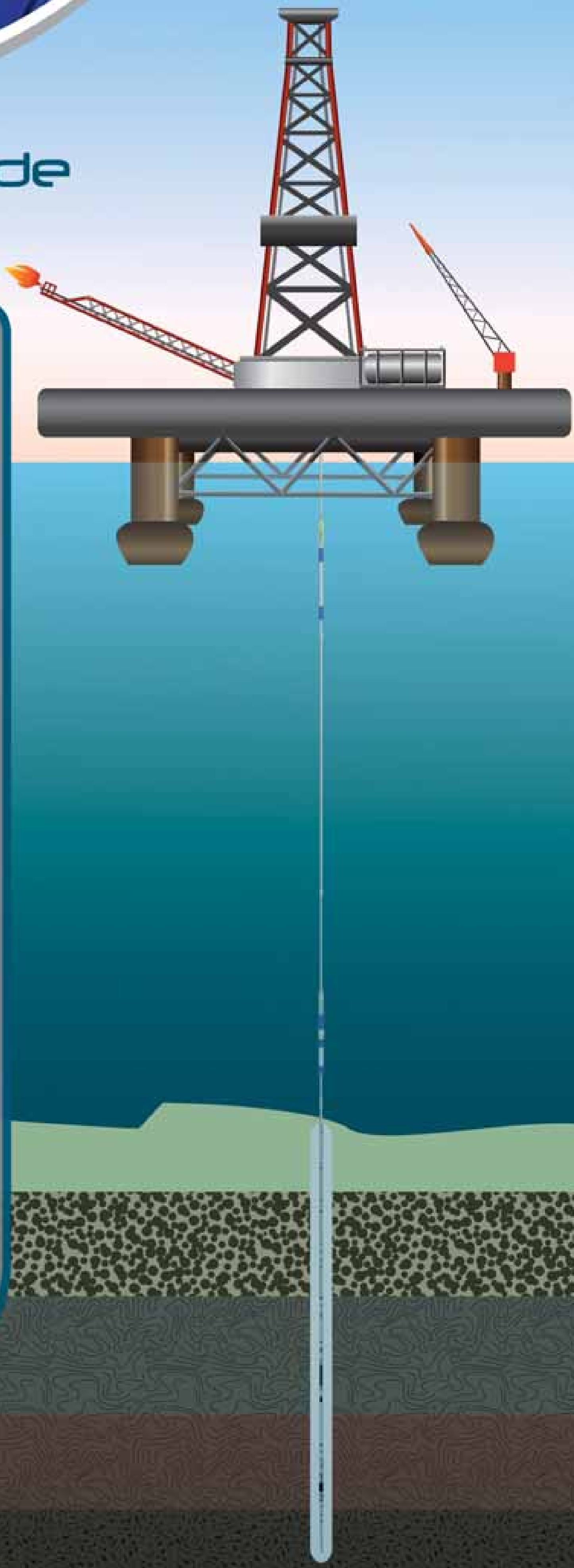

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Reliability Key to Long Term Injectivity Test

By Mubarak A Dhufairi, Khalid Al Omairen, Saudi Aramco, and Paul Docherty, Schlumberger.

A complex carbonate oilfield in Saudi Arabia required pressure support to sustain production. Saudi Aramco was looking to achieve sustained production using the best in-class reservoir management practices. The natural drive mechanism came from an aquifer screened from the overlying reservoir by a semi-impermeable tar mat, the geometry of which was relatively unknown, although it was thought to be continuous. Even so, it was suspected that the tar mat might not be completely sealing. Accordingly, any enhanced oil recovery (EOR) plan using traditional water injection would not be effective. This article describes a comprehensive, long-term injectivity test whose objective was to characterize reservoir sweep patterns so the optimum number and location of injectors could be determined.

Well Placement Was Critical

The initial approach to avoiding the tar mat issue was to geosteer horizontal injector wells so they landed just above the tar mat, in the transition zone between the heavy and light oil. Geologist and reservoir engineers were faced with the challenge of placing the injectors optimally, so injection water would drive crude oil to the producing wells, leaving no movable oil residuals behind.

Before the entire reservoir pressure support scheme was committed, two pilot tests were designed involving a single injector well and six producers located at varying distances and directions. The six producers were intended to be utilized for observation and to monitor the rate of pressure build up with time for each. The producers/observation wells were equipped with downhole permanent and/or retrievable, high-accuracy, long-lasting, battery-powered electronic gauges. It was decided to perform a long-term injectivity (LTI) test with the objective of mapping the sweep pattern and effectiveness of the injection scheme, in addition to qualifying the injection wells placement strategy. Therefore, to obtain supportable results, a massive test was envisioned involving some 3 million bbl of injected water over a 200-day period. Reliability, resolution and accuracy of the downhole gauges was absolutely essential because it was predicted that changes due to injection water could be quite subtle, particularly on the most remote wells in the observation pattern. At the same time, reliability of the injection setup and equipment was equally important. Any breakdowns could completely mask the data transients the engineers were trying to measure.

Design AnticipatesTough Conditions

With such reservoir conditions, proper placement of injection wells relative to producing wells was of paramount concern to deliver production targets with the highest sweep efficiency model. Robust dual memory electronic gauges capable of withstanding sustained high temperatures for at least 31 weeks were specified. The observation wells were equipped with electronic gauges to monitor reservoir pressure response during the LTI test to confirm reservoir lateral connectivity and possible vertical communication between reservoir layers.

In an effort to aid the overall reservoir characterization, the injection well water profile was planned to identify the contributing zones across the horizontal section and map out the crossflow areas. Furthermore, plans were put to record an II/fall off test, which should be analyzed and compared to several pressure transient measurements recorded in several appraisal wells drilled during the project planning period. These measurements served to identify the fluid profiles in those wells along with any anomalies such as crossflow between reservoir levels that might skew pilot test results. The fact that the pilot test was conducted in a dynamic field environment meant that each pressure disturbance had to be accounted for so the final analysis would truly represent the interaction of the pilot test model of a

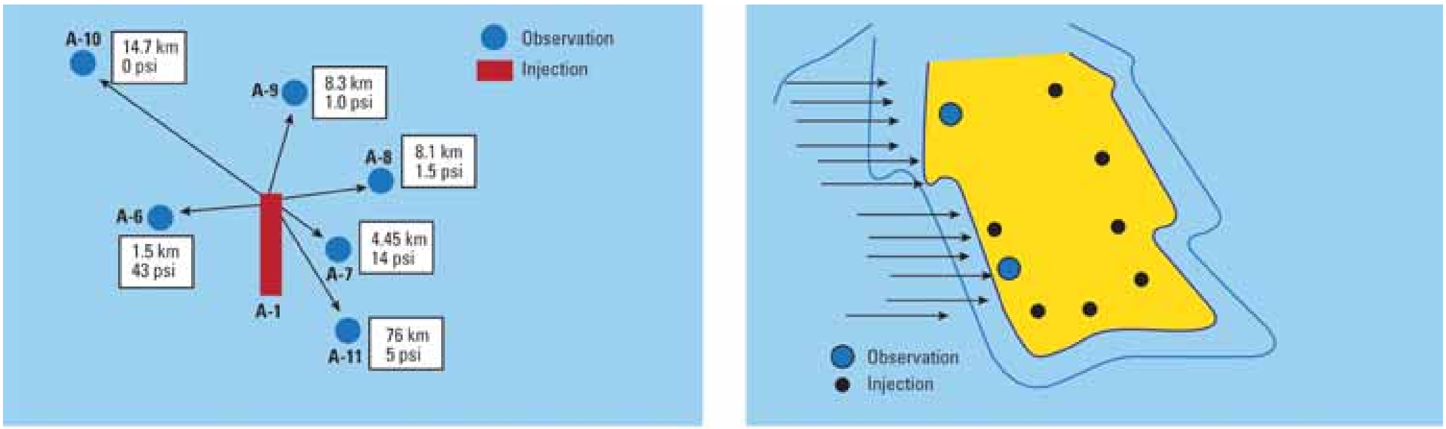


Figure 1: Pilot test well layout includes distance and direction from injection well to observation wells along with observed pressure increase over the test interval. [SOURCE: OTC 21130 Figure 3 with callouts]

single injector with six observation wells and no outside effects.

A comprehensive test methodology was planned. Pre- and post-injection measurements would be taken that would include both injection and fall-off tests. Thorough transient analyses were planned including:

• Crossplots of differential pressure vs. logarithmic Horner time
• Crossplots of differential pressures and the square root of time
• Crossplots of logarithmic differential pressure and the log of time
• Crossplots of the log of the pressure derivative and the log of time derivative.

Using derivatives is a traditional technique because the derivative is directly represented by one term of the diffusivity equation, the governing equation for models of transient pressure behavior in well test analysis.

Injection Wellbore Cnditioning

A complicating challenge lay in attempting to return injectors to their original status. During drilling, several of the injection wells experienced lost circulation into natural fractures in the carbonate sequences. These were mitigated by pumping viscous pills of hydroxyethylcellulose (HEC) polymers. As a result, many, if not most, permeable zones had high skin damage. To clean up the damage and restore the original skin effect, acid treatments were pumped. To maintain control over the test data, pre- and post-treatment injectivity tests were run. The skin mitigation program was not without its challenges. Deployed into the lateral using coiled tubing pulled by a downhole tractor, the tools became clogged with lost circulation material. A solution was implemented involving bullheading 300 bbl of solvent to dissolve the material that was affecting the control assembly of the tractor.

The post-treatment injection measurements, made using downhole gauges deployed on slickline, consisted of pumping 20,000 bbl of treated seawater into the formations; then pausing to conduct a pressure fall-off test. The fall-off test, which took 96 hours, provided vital information regarding the parameters of the injection scheme. Near-wellbore skin, interwell average reservoir pressure and permeability were determined.

Injection well performance was assessed using Hall-effect plots, based on injection volume and surface injection pressures.

Surface Facilities Designed for Reliability

To avoid further complications, considerable forethought was built-in to the surface system. Basically the plan was to use treated seawater, pumped through a 1.9 mile (3 km) 6-in. diameter pipeline. At the injection well site, two, 2-micron,Vortisand™ sand filters were deployed plus a chemical injection module before the water was pumped into eight, 500 bbl skid-mounted holding tanks. The tanks supplied a set of electrically-powered triplex charge pumps providing input to the horizontal above-ground ESP pumping system (HPS). The pumps were energized using a Schlumberger variable speed drive (VSD) powered by three 500 kVA generator sets.

At the intake, duplex diesel-powered pumps drew seawater from a shallow seaside location. These proved to be unreliable and were replaced by duplex submerged ESPs supplied by a motor generator. To assure the LTI

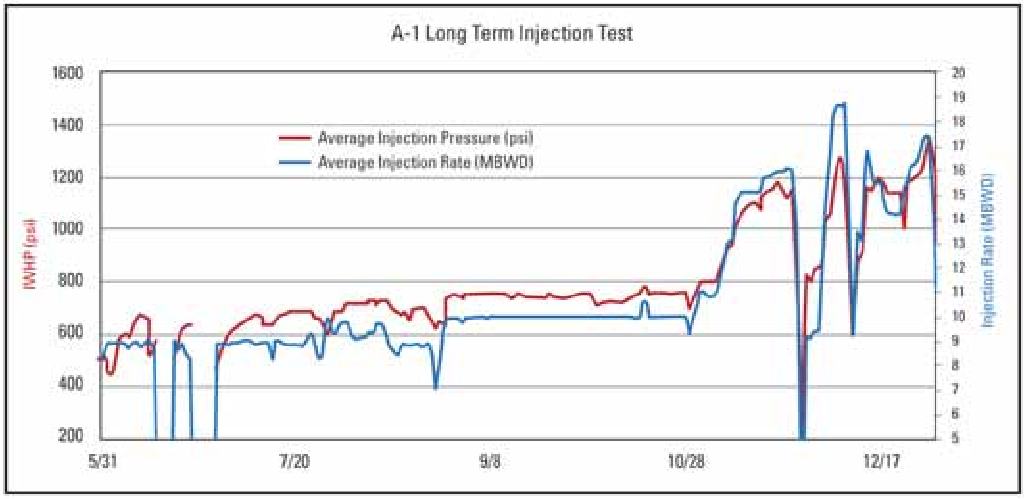


Figure 2: Injection wellhead pressure (red) and injection rate (blue) are plotted as a function of time. [SOURCE: OTC 21130 Figure 4 with callouts]

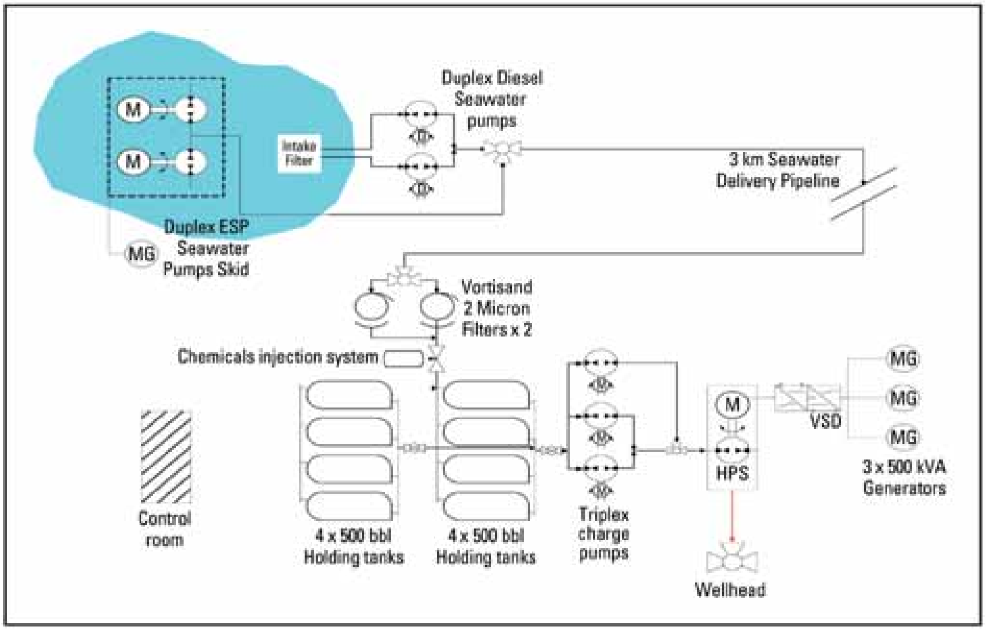


Figure 3: Test schematic illustrates redundancy and integration of reliable ESPs at the seawater intake and at the wellhead HPS [SOURCE: OTC 21130 Figure 1 with callouts]

test as a reliable source of injection water, the ESPs were determined to be the best solution. The original diesel pumps were retained onsite as backup. System design capacity was 20,000 bbl/day. At the wellhead, the HPS delivered 10,000 bbl/day of filtered, treated seawater at up to 2,500 psi.

During the design and construction of the surface facility, several important lessons were learned:

• Ensure pump intakes were deep, clean and clear of sand and debris
• Ensure pump not deadheaded into a closed valve
• Address careful alignment of shafts
• Provide a compressor to facilitate system maintenance
• Install tank supports to keep bottom valves accessible
• Use duplex pumps to provide system integrity and backup
• Provide concrete bases for rotating equipment
• Install a subsurface safety valve to block H2S flowback from well
• Perform full review of generators and VSDs for compatibility

Injectivity Tests Reduce Uncertainties, Save Money

The pilot injectivity tests were very successful. Dynamic data, including pressure transient analysis, removed several faults from the geological model. At least 13

Figure 4: The use of modular equipment facilitated transportation and setup in the desert and added flexibility to the system design as items were substituted to improve reliability. [SOURCE: OTC 21130 Figure 2]

injector wells were dropped from the field development plan, largely because uncertainties about the tar mat sealing were redefined. System design issues were successfully resolved to address test goals and result in almost 96% uptime. It was determined that lower powered water injector pumps were required because the injectivity index turned out to be better than expected, and ESPs proved more reliable than diesel-powered pumps. Schlumberger pressure gauge systems and permanent downhole monitors proved both rugged and reliable over the 31-week test period in a hot and highly corrosive environment.

Importantly, data integration with other sources such as drilling data, field production history, available geology and petrophysical analysis from well logs all helped to mitigate risks of skewed interpretation.

---

*Mark of Schlumberger

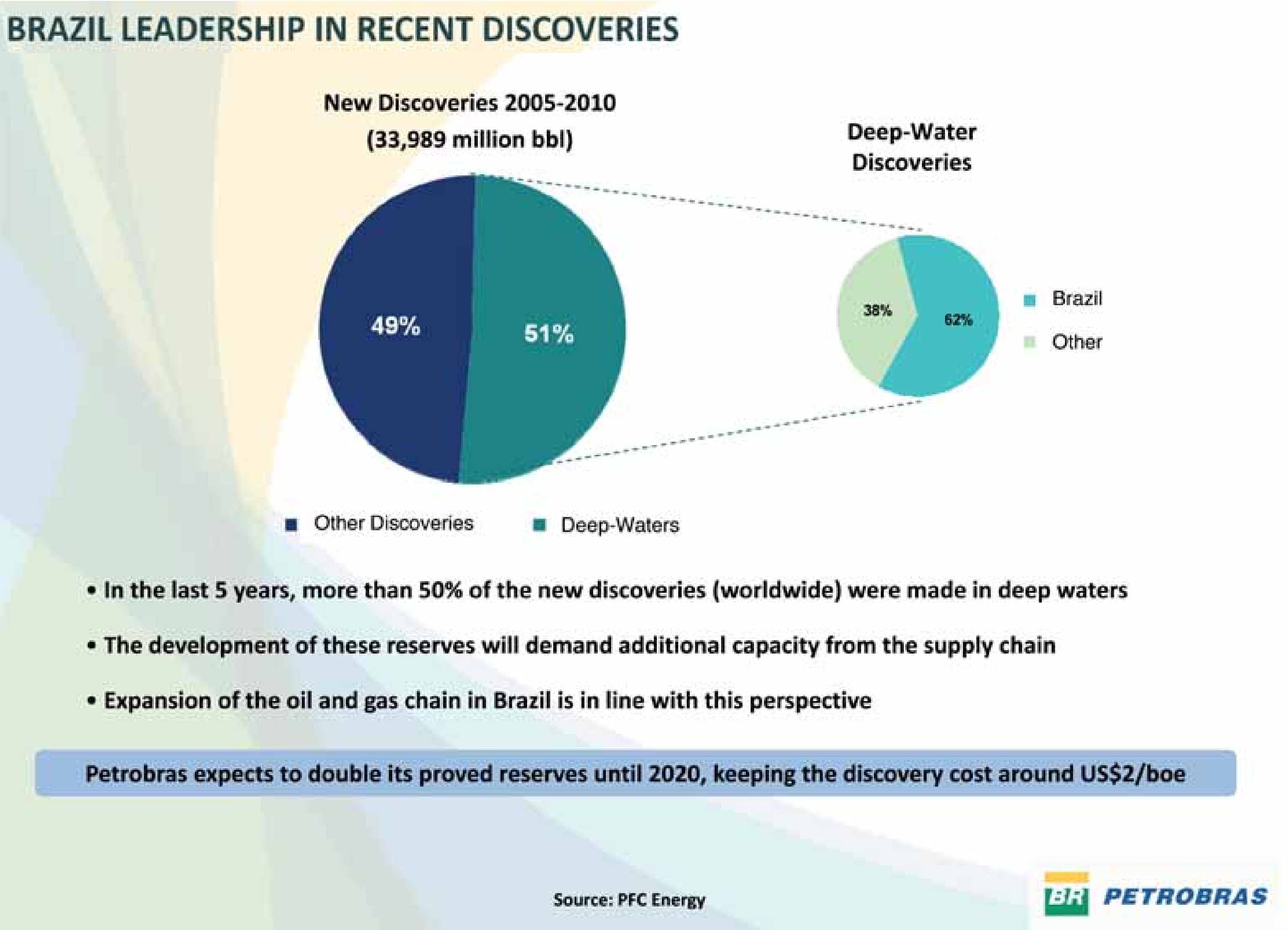
Biographies

Mubarak A. Al-Dhufairi is a Production Engineering Supervisor of the Manifa development. His experience includes working on several fields, including Safaniya, Shaybah and Berri fields, along with his experience in drilling engineering. Mubarak received both his B.S. and M.S. degrees in Petroleum Engineering from King Fahd University of Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

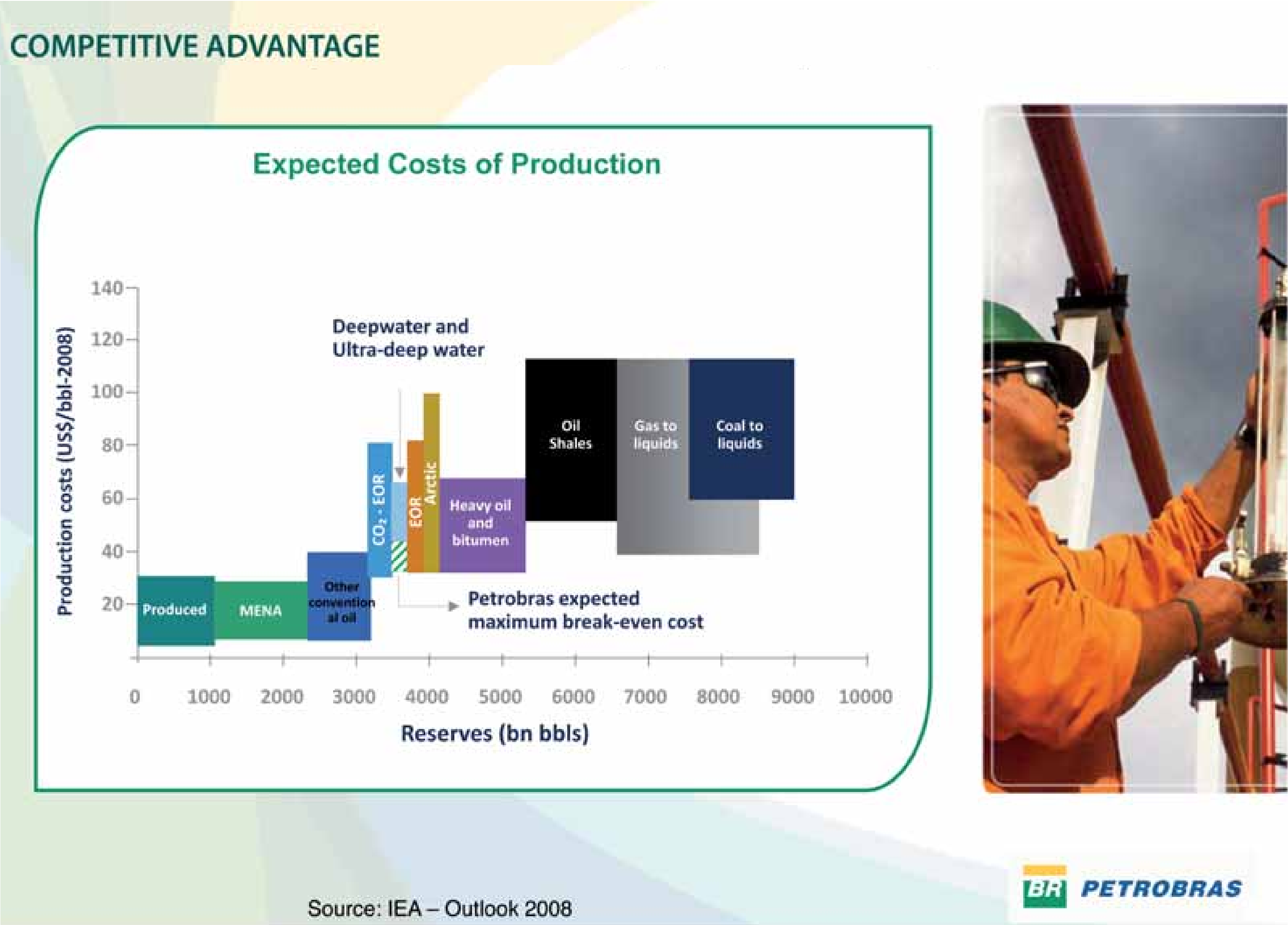
Khalid Al-Omairen holds over 25 years of experience in the Oil & Gas industry. His first assignment right after graduation was with Production Engineering for Aindar field in 1986. Later on, he worked as a Foreman and a Superintendent for several offshore and onshore facilities, including Northern Area Oil Operations (NAOO) Well Services Division. Currently, Khalid is the General Supervisor of Safaniya Production Engineering Division overseeing over 2 MMBOD. He has a unique passion to create a work culture attached to continuous simplification of the routine through the adaptation of new technologies and process improvement, a culture that is proactive and flexible enough to accept change and resist returning to old time thinking. Khalid received his B.S. degree in Petroleum Engineering from the University of Louisiana, Lafayette, LA.

Paul R.J. Docherty is an Electrical Engineer. He worked for Shell and Esso as an Electrical Engineer on the FLAGS project upon leaving university, before moving to BP Wytch Farm and joining the ESP Task Force at that location. Paul has some 25 years of experience in ESP Systems, having worked for Schlumberger for 22 years in various capacities. He received his Polytechnic Diploma from Northumbria University, Newcastle, U.K.

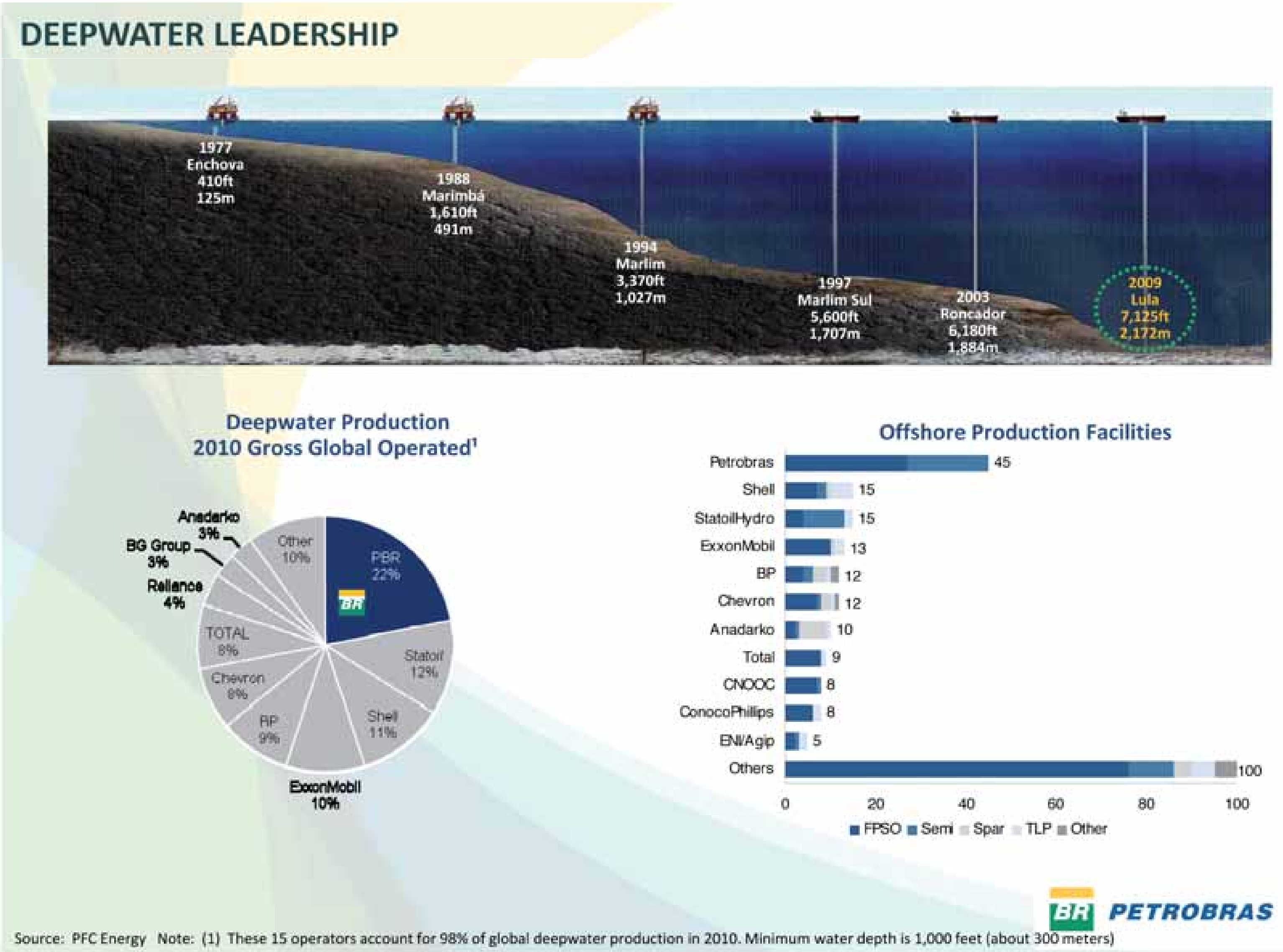
Petrobras Strategic Plan



"Deep-water discoveries in Brazil represent a third of the worldwide discoveries in the last five years."

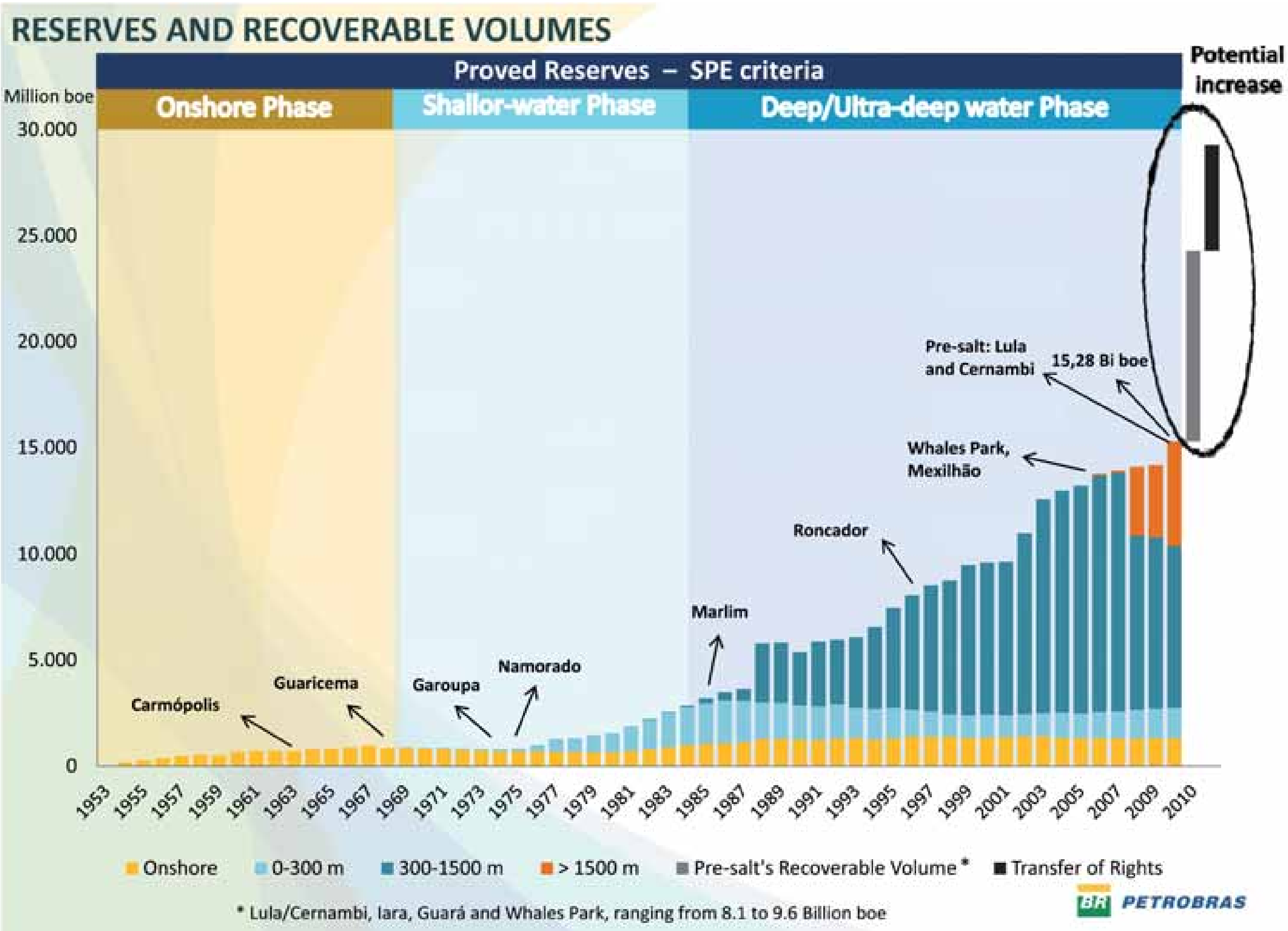


“Reserves in ultra-deep water in Brazil benefit from comparatively low break-even.”

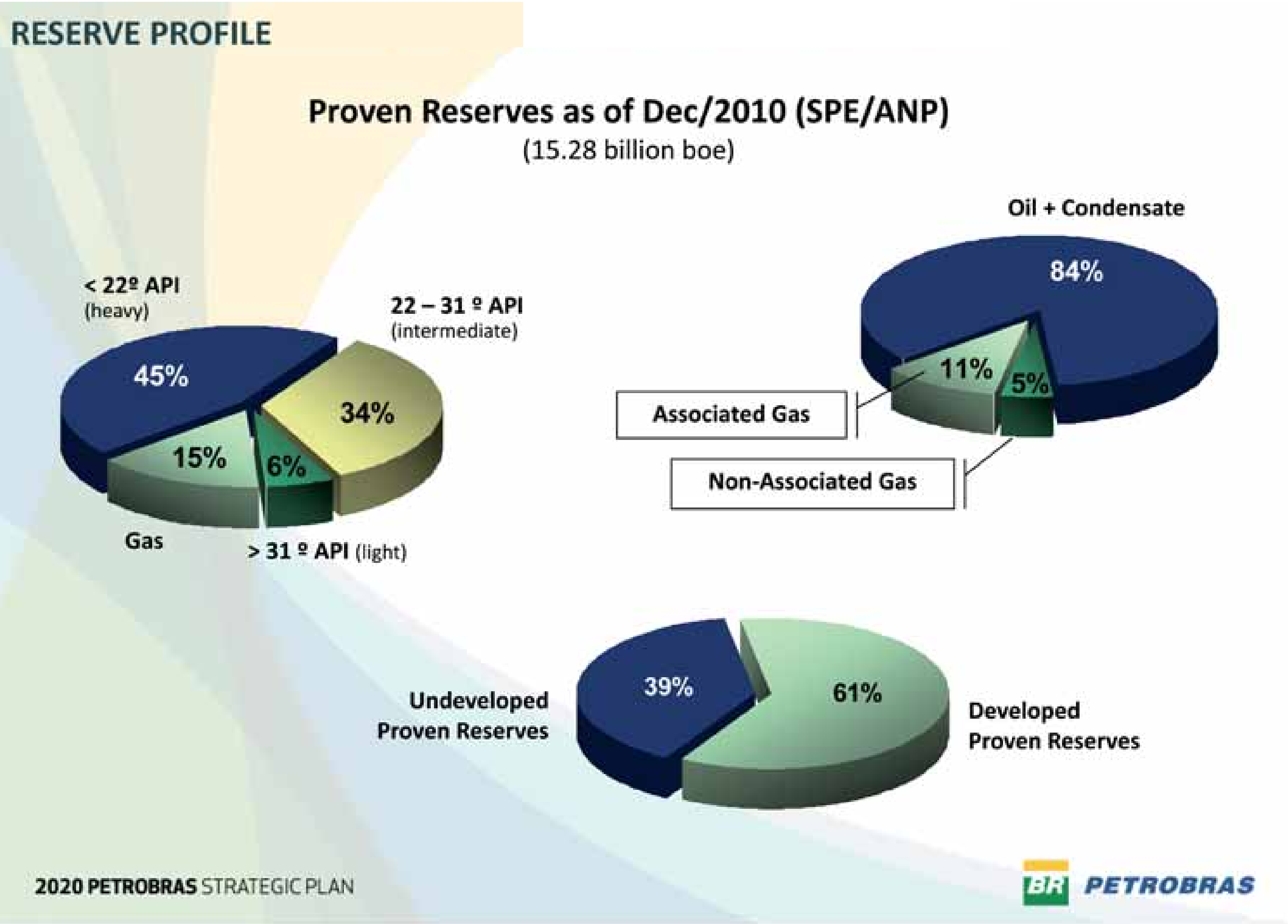


“A history of developing technology and know-how in Brazilian waters.”

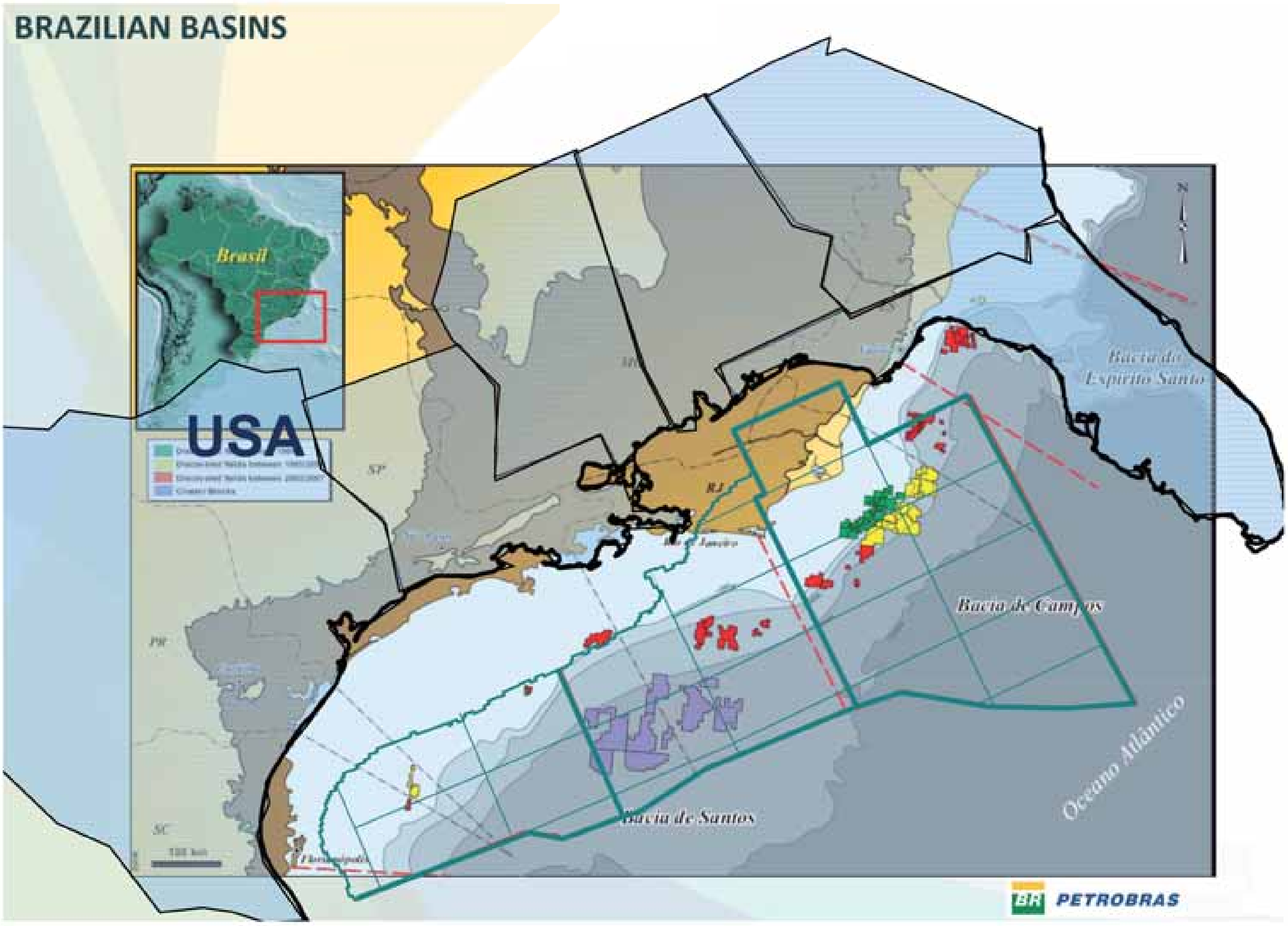
"Sustainable development of hydrocarbon reserves."



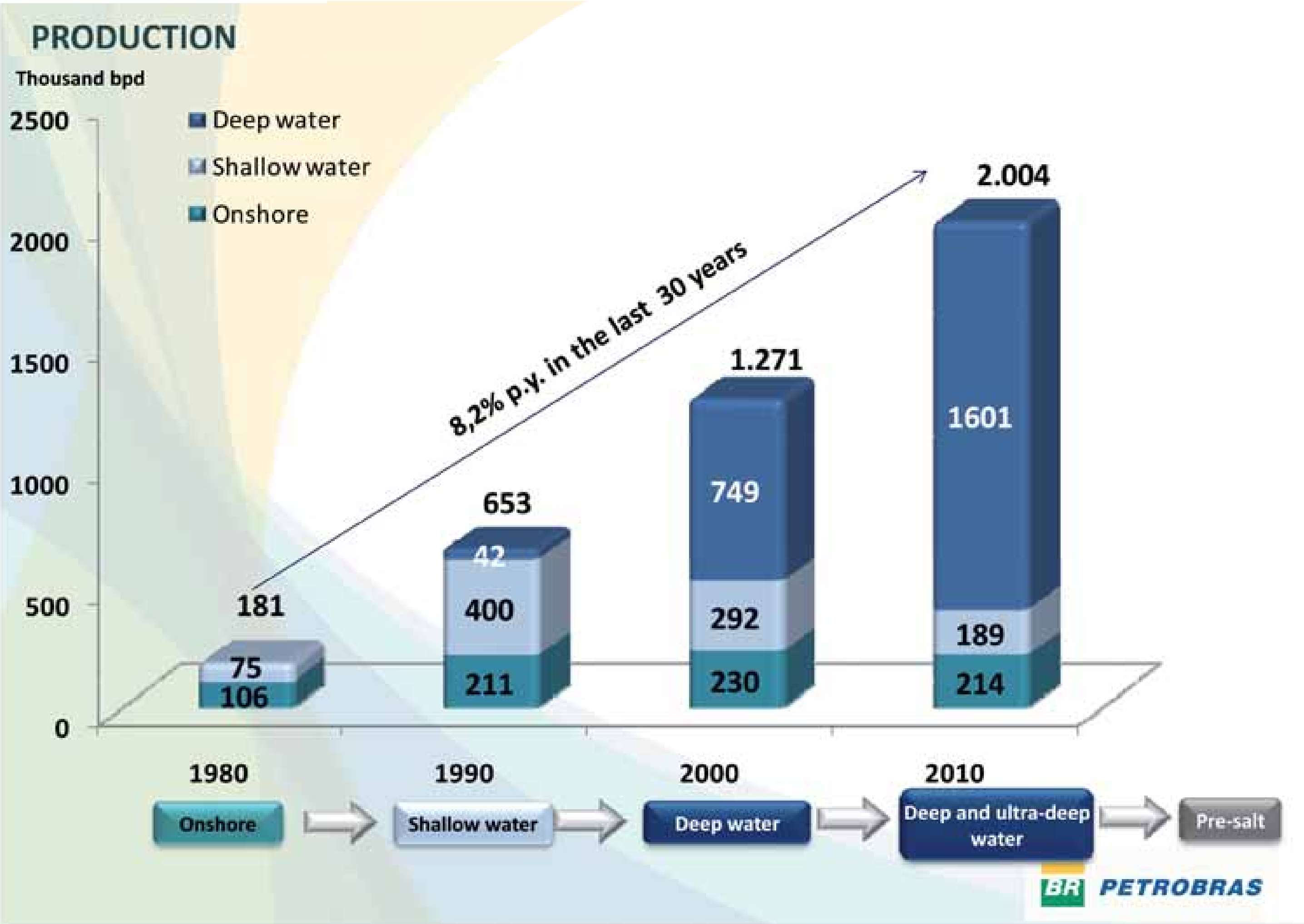
“Rapid growth in reserves from discoveries in deep waters.”



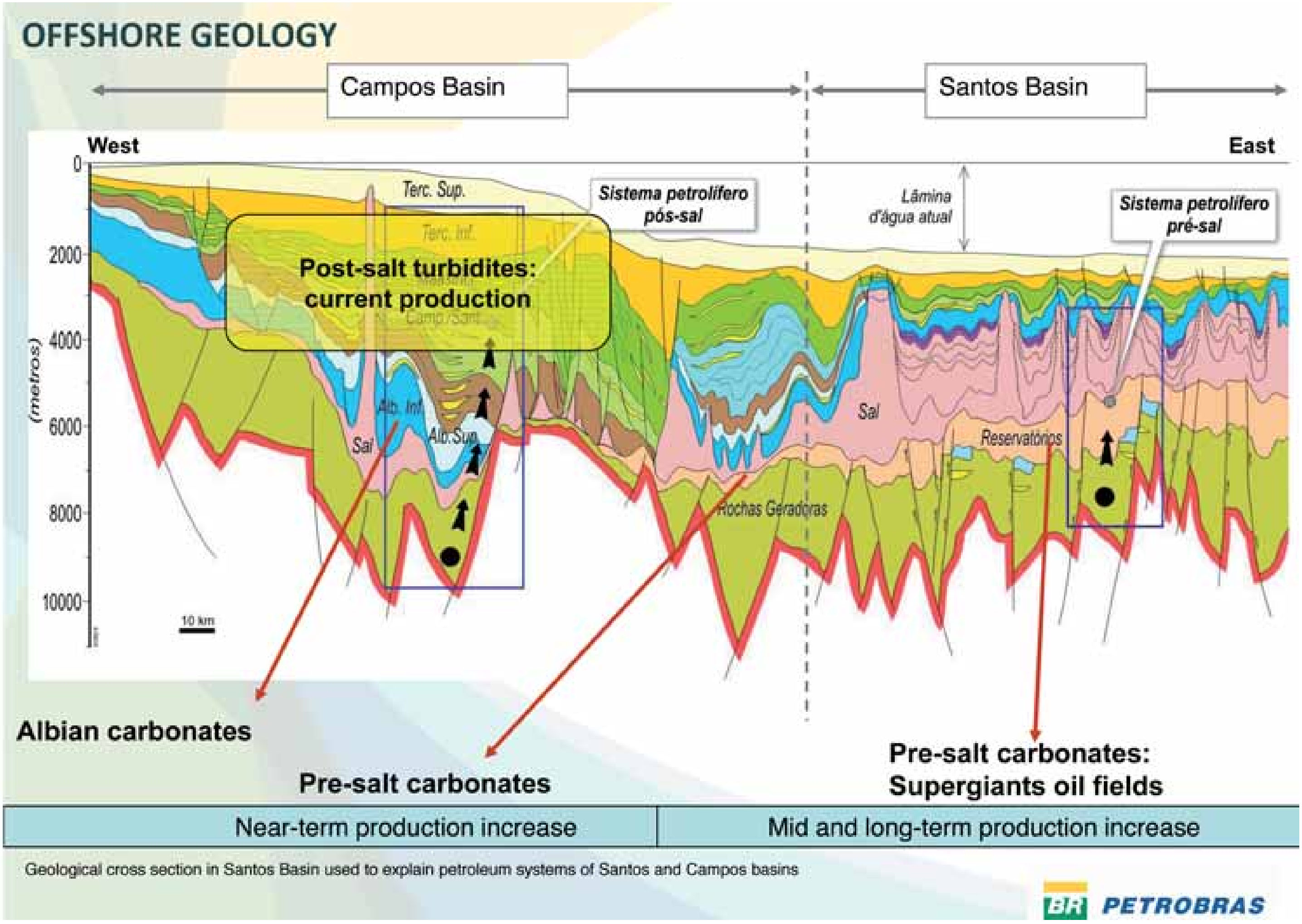
"Proved reserves consist largely of offshore oil that is relatively heavy."



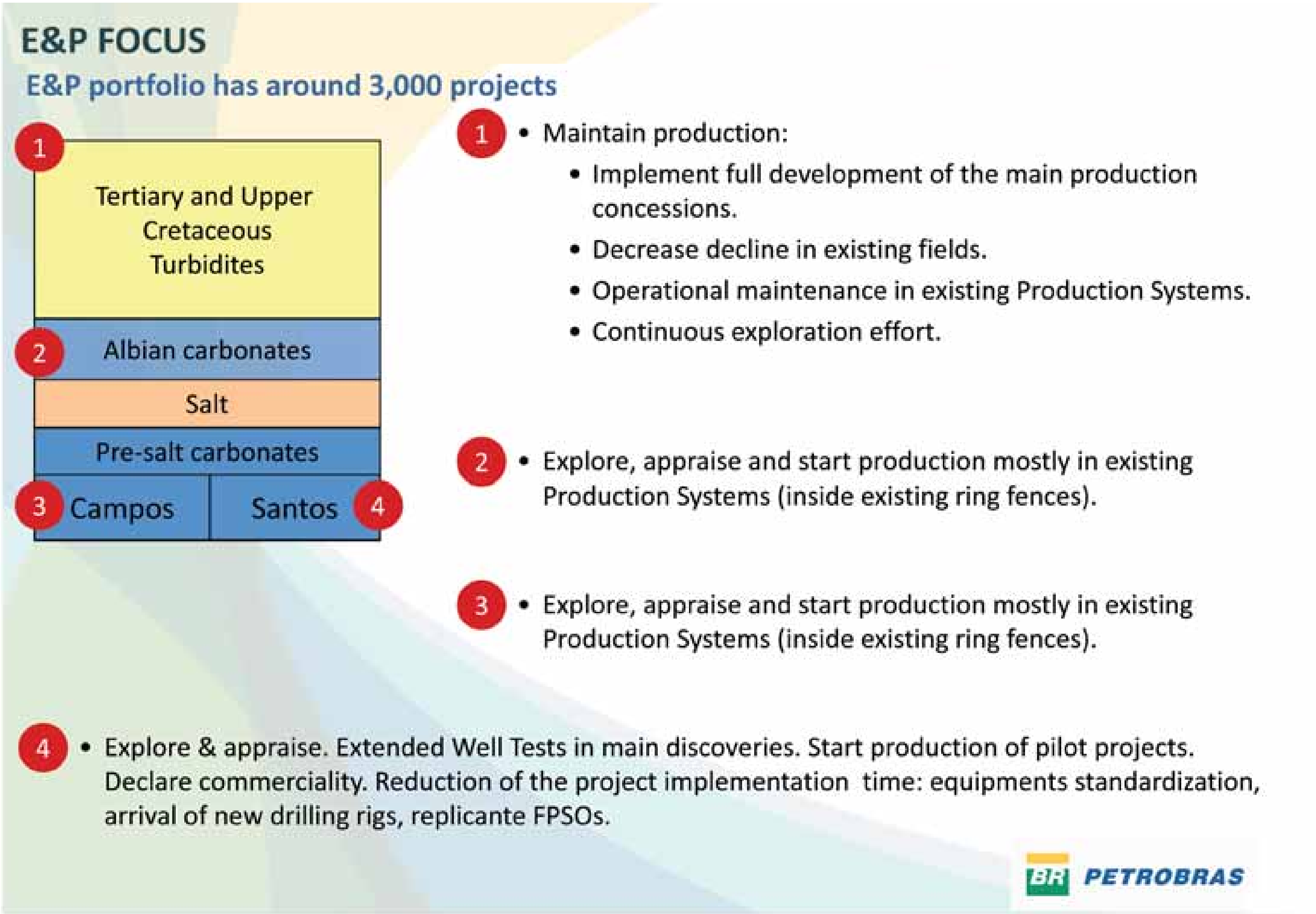
“Offshore Brazil is a vast area,
still unexplored.”



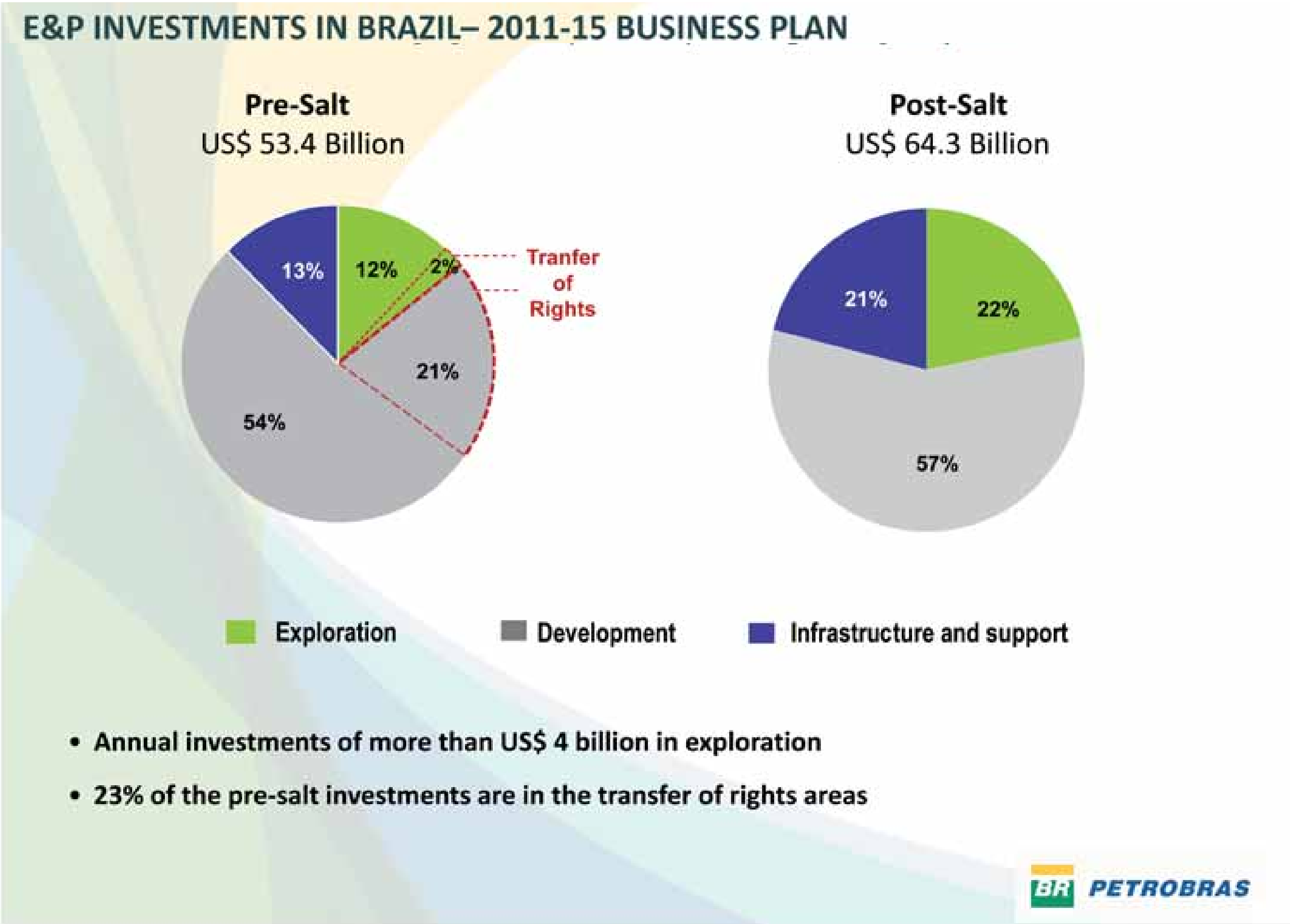
“Petrobras history is to grow production by expanding into new frontiers.”



“Producing from pre-salt reservoirs will drive future investment.”

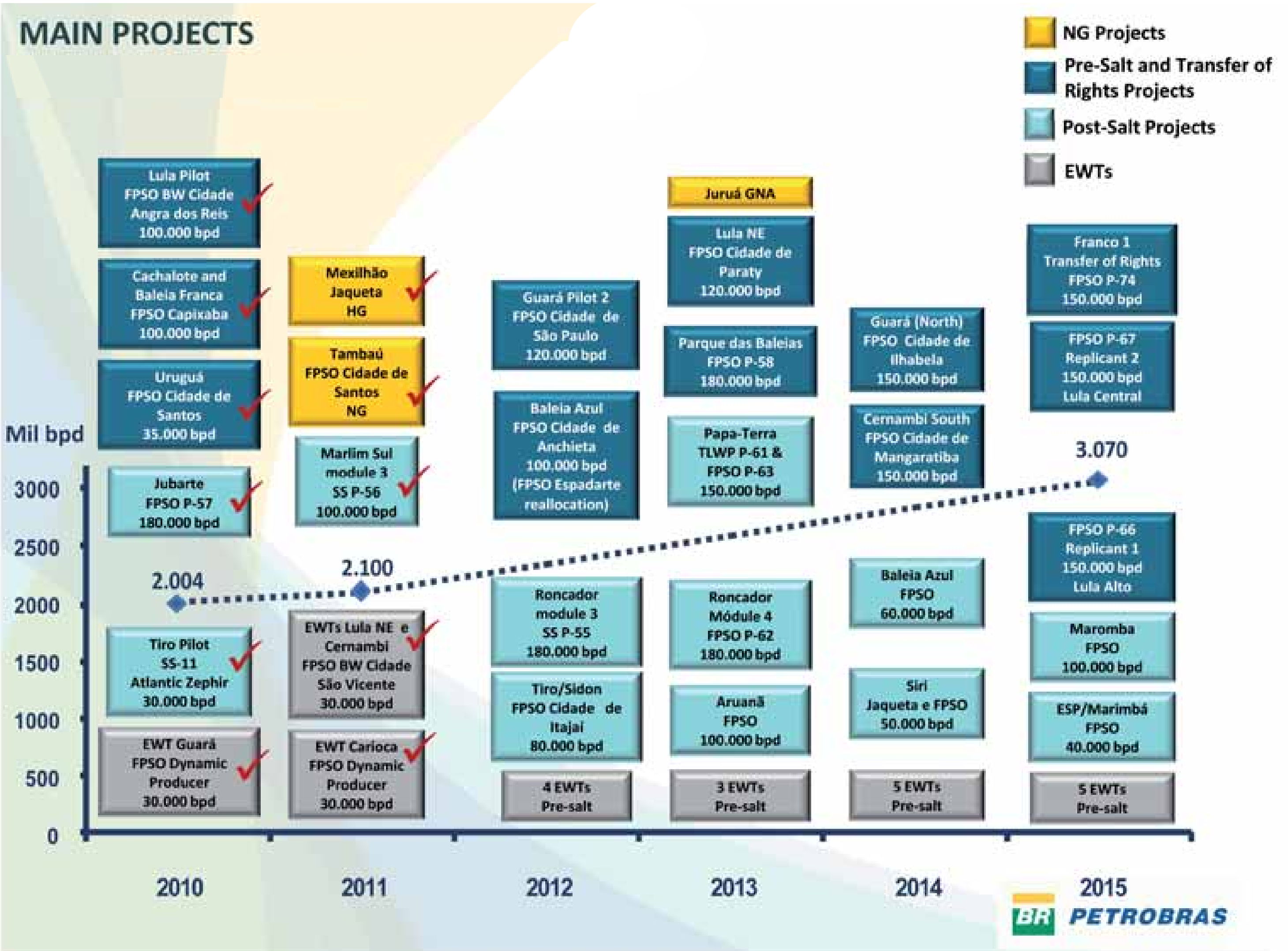


“Maintain and expand traditional areas, while transitioning to new reservoirs.”



“Pre-salt now more than half of development spending next five years.”

“Sixty-six offshore exploratory wells expected in 2012.”



> "Large projects sustain production increases."

NEW PRODUCTION UNITS 2012

Development Project	Capacity (thousd. bpd)	Petrobras %	Forecast
Tambaú	Natural Gas	100% PBR	1Q 2012
Pilot Baleia Azul (Pre-salt)	100	100% PBR	3Q 2012
Tiro Sidon	80	100% PBR	3Q2012
Roncador mod. 3 SS P-55	180	100% PBR	4Q 2012
Pilot Guará (Pre-salt)	120	45% PBR	4Q 2012

Additional Total Capacity - Petrobras: 414 thousand bpd

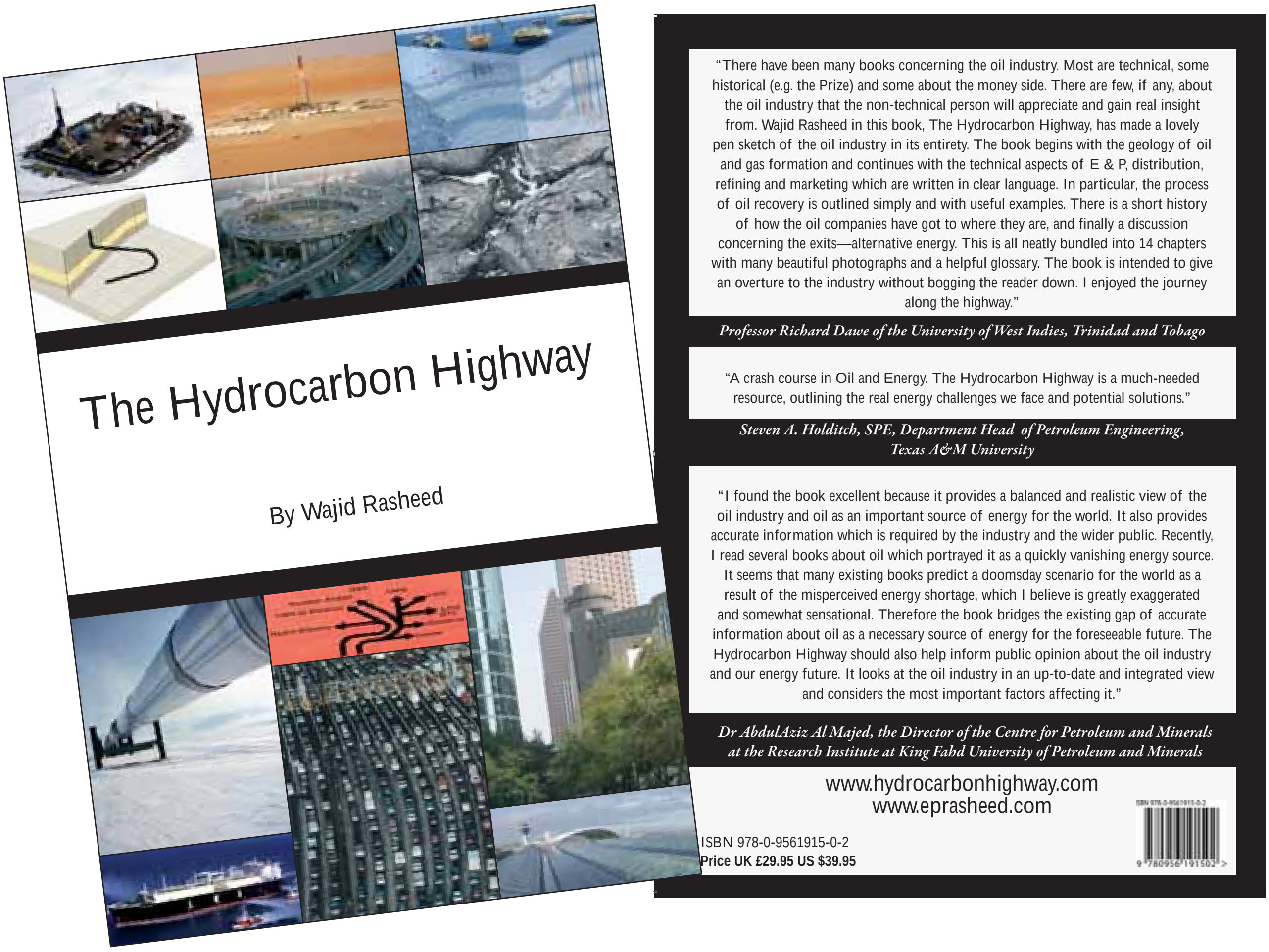
- 8 ultra deepwater rigs have arrived during 2011. 15 more contracted to arrive by end of 2012.
- Additional rigs will accelerate ramp-up of new systems.

PETROBRAS

“Production capacity growth above 400 thousand bpd during the period.”

Extreme E & P

A Chapter from The Hydrocarbon Highway,
by Wajid Rasheed



Worldwide, the exploration objective is clear: locate new frontiers and reserves. Every new frontier, however, brings new problems that are not always easy to predict. In this chapter, we look at the development of oil and gas reserves that are tough-to-produce due to their location in extreme environments.

It is fashionable these days to use different labels to distinguish particular types of drilling: Arctic, deepwater, and High Pressure High Temperature (HPHT) practices. The common denominator of all drilling activities is the management of people, technology and processes. Customs, environmental and legal issues also exist as does the detail of prospect selection. That's fine.

This logistical labyrinth is essentially the same whether you're sitting in a company man's office in

Adding to the location issue are government regulations restricting vast areas of land onshore or offshore from drilling activity on environmental or public opinion grounds.

offshore Angola or onshore Azerbaijan. Technology applications aren't necessarily exclusive to deepwater either. Smart completions using fibre optics and satellite communications are enabling the production of multiple zones to be co-mingled and controlled. Acidisation through water injection lines permits live well intervention without skidding land rigs. New gravel packing and filtering techniques can be used to control sand production in shelf fields. In fact, it seems an equally compelling case can be made for technology to be used in onshore or shelf locations to improve marginal economics as can be made for deepwater operations[1].

So what are the differences behind the drilling labels? Let's look at them.

Location

'Location, location, location'. The mantra of property gurus could equally be applied to oil and gas reserves. After all, location determines the ease or difficulty with which reserves can be accessed and this in turn is a major determinant of finding and lifting costs.

Clearly, access to oil and gas reservoirs is restricted in extreme environments. In Arctic areas, it is restricted due to severe seasonal weather conditions. Alaskan Arctic exploration, which mostly involves onshore projects, is restricted by access to the tundra and the conditions that enable ice roads to be constructed over the permafrost or across the shallow coastal waters to get to the exploration sites. In deepwater, restrictions are created by increased water depth. HPHT conditions restrict access in other locations. Perhaps, the most difficult and costly combination for oil and gas Exploration and Production (E & P), is the well-from-hell – a combination of Arctic, deepwater and HPHT conditions.

In this way, a sliding scale of costs exists—from the deepwater Arctic wildcat (with HPHT contingency) to deepwater to the Arctic to deep shelf HPHT or deep onshore. Adding to the location issue are government regulations restricting vast areas of land onshore or offshore from drilling activity on environmental or public opinion grounds. The State of Oklahoma used to be proud of the fact that it had a pumping oil well on the property also occupied by the State Capitol building. Such a thing would be unthinkable today. Fortunately, Extended Reach Drilling (ERD) technology has alleviated many of these types of problems. The famous THUMS man-made islands offshore from Long Beach, California were constructed by a consortium of oil companies: Texaco, Humble, Union, Mobil and Signal. From the beach, they looked like beautiful semi-tropical

In all parts of the world, environmental considerations are important, and if not properly addressed, delays in obtaining a drilling permit can result.

islands housing luxury condominiums. In fact, the 'condos' concealed drilling rigs and the outbuildings concealed production facilities. Similar 'Hollywood' tactics were employed in downtown Los Angeles, where drilling rigs in soundproofed building shells were sited along famous Sunset Boulevard, unseen and unknown by the general population. Wells from these sites were directionally-drilled outward for thousands of feet to tap prolific oil reservoirs under the city.

E & P Finding and Lifting Costs

As we saw in *Chapter 4: The Fall of the Oil Curtain*, E & P in tough-to-produce environments costs more. Technically challenging environments create a series of engineering, technical and financial needs that do not exist with easier-to-access counterparts. These needs range from higher-rated equipment, such as upgraded or specialised rigs, as well as dedicated field development techniques. Wildcats or poorly characterised conditions create contingency scenarios. In these cases, a single well plan will have several casing and completion contingencies which must all be budgeted[2]. Contingencies can include HPHT conditions or tight Pore-Pressure/Fracture Gradient (PPFG) windows creating the need for revised casing depths and increased casing strings[3].

Seasonal challenges such as those associated with offshore Arctic conditions will also create technical and financial challenges due to a narrow window for operations before they are interrupted by ice formations[4].

Keeping Costs Down

Undoubtedly, deeper water environments add greater cost and complexity to operations; however, these expenses can be cut in three ways.

Firstly, we could simplify the well design. Well trajectories should not only be compared in terms of how effectively targets are reached, but also on their overall cost effectiveness. Secondly, we could reduce the number of casing strings. Casing can be set deeper, based on real-time PPFG detection. Accurate prediction will reduce contingency casing. Offset data can help to refine pore pressure models and enhanced pore pressure detection will make the best of the casing programme while drilling. Modelling steady and dynamic state fluid behavior will reduce surprises. Last but not least, costs can be cut by contracting 'fit-for-purpose' technology, especially on rigs.

Simplified well design may be possible based on setting casing deeper. Real-time PPFG detection and prediction reduces the number of contingency strings.

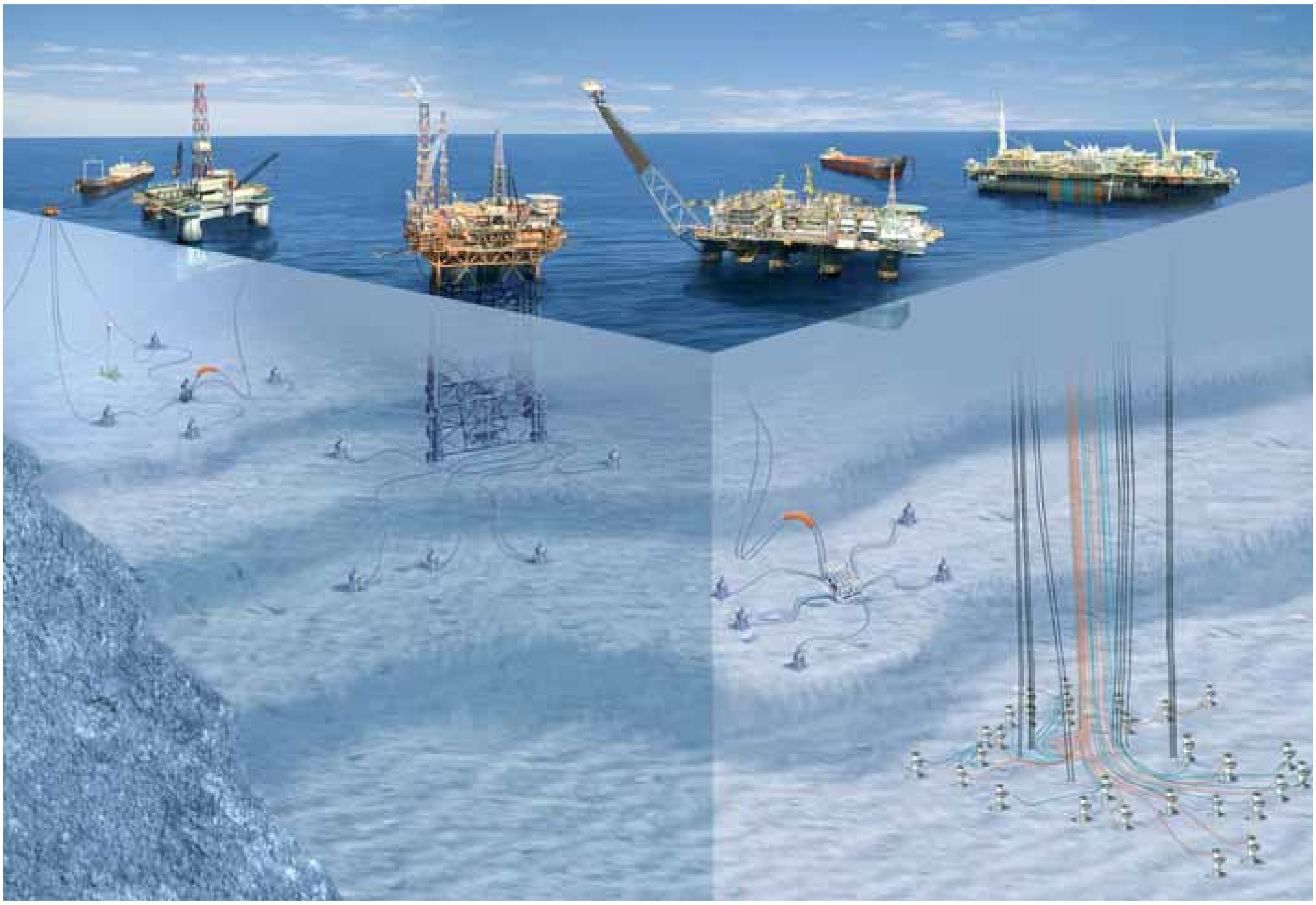


Figure 1 - Fixed and Floating Production Units For Deepwaters (Petrobras)

Eliminating casing strings by taking calculated risks during well construction can reduce mechanical risks and lower costs. Where offset data exists, more accurate pore pressure models can be constructed. Enhanced pore pressure detection will optimise the casing programme during drilling and will reduce costs. Logistics and importation issues should be fully understood as this can reduce the need for pre-deployment of contingency equipment. All of these opportunities, combined with adequate planning processes, time and resources will cut costs[5].

Arctic Seismic

Acquiring and interpreting geophysical data helps reduce some of the risk associated with exploration. In Arctic environments, logistical and technical challenges accompany seismic. Shooting seismic data can only be conducted within a seasonal window of good weather (usually three to six months). Interpreting seismic data is also challenging as seismic must penetrate thick sheets of permafrost (in rare cases up to 3,280 ft [1,000 m]) which creates noise and weathering problems and ultimately interferes with attribute analysis and structural imaging[6].

Deepwater Seismic

Geotechnical and oceanographic data supplies exploratory deepwater asset teams with seabed and water column information which is necessary for well construction and production activities[7]. Getting deepwater seismic is, however, very difficult. In the case of deepwater frontier drilling – wildcats – oil companies must also perform what are at times unprecedented seismic programmes. This has led oil companies to initiate various projects to refine oceanographic data from deepwater basins. Comprising geo-hazard assessment, geo-technical characterisation and slope stability, these projects help identify and characterise potential geo-hazards. The aim of the geo-technical characterisation and slope stability analysis is to investigate seabed sedimentary properties and to model slope stability through surveys and integrated

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geological data. Reservoir and production engineers use data such as seabed and water column to optimise production[8].

Other projects include exploratory seismic 3D, high resolution sonar and bathymetry. Exploratory 3D seismic is used for rendering seafloor and underlying structures while the seafloor texture is mapped by sonar. Cores are used to 'ground-truth' geophysical interpretation and date geological events[9].

In certain deepwater basins, studies concentrate on mapping salt structures and seeing what lies beneath them. Active salt tectonics play an important role in shaping the seafloor and salt-induced topography and fluid seepage are investigated. Continental slopes may be the focus of geo-hazard assessment, while oceanic current-induced seabed erosion may also be studied[10].

Further oceanographic data will also be acquired using satellite images, Sea Surface Temperature (SST), Sea Surface Height (SSH) and radar data. This information, along with pre-existing data, will validate oceanic models. As a result, extreme currents will be analysed to identify instabilities. In this way, a picture of the deepwater operation is built-up and incorporated into an in-house database that can be queried.

Oceanographers know that the sea can be a complex environment with temperature inversions and subsea loop currents at different levels and in different directions. Deepwater offshore structures, for example, are the victims of Vortex-Induced Vibration (VIV) caused by sea currents interacting with tubular riser pipes. Unchecked, this VIV can totally destroy a production riser in a matter of a few days or hours. Oceanic currents affect the velocity of seismic waves, and if unaccounted for, can produce erroneous results when the seismic section is interpreted[11].

Deepwater Wildcats

Deepwater portfolios are important for the long-term renewal reserves especially for International Oil Companies (IOCs). Basins in offshore areas such as West Africa, the Caspian Sea, Gulf of Mexico (GOM) and Eastern Brazil are very highly sought after production opportunities for this reason.

Irrespective of resources or experience, however, picking and drilling deepwater prospects is tough. Imagine having to pick and drill two wells from within an unexplored area of 9,000 sq mi (25,000 sq km – equivalent to 1,000 GOM blocks)[12].

With the potential *dryhole* risk in mind, IOCs will seek to reduce risk by entering into agreements with other oil companies before exploring. Many of these partners

Figure 2 - Subsea Riser (Petrobras)

will be companies that have similar concessions and can bring technical know-how to the deal.

Organizational Challenge

In order to deliver wildcat wells in frontier regions, oil companies need to manage different working cultures, languages and physical locations. They will have to work through many issues with local government, customs, environmental, and legislative bodies. They will also have to agree on prospect selection with their oil and gas partners.

Enrolling and focusing the drilling team is often achieved through 'Training to Reduce Unscheduled Events' (TRUE) and 'Drill the Well On Paper' (DWOP) exercises. Major changes, however, can take place during operations; for example, prospects and contractors can be changed. Problems with equipment or facilities can also cause major delays. With a high-end rig on rental, these costs can quickly eat through the largest of budgets. Success in dealing with these late changes depends mostly on the support that the oil companies receive from sister deepwater teams[13].

Planning Exploration

With frontier locations, it is often the case that little or no infrastructure is in place. This means that many challenges associated with the frontiers' remoteness must be assessed and overcome. This can include setting up onshore supply bases, access routes and overcoming the logistical issues associated with the equipment and services required for E & P.

Poor transport links means that look-ahead logistics and transport options will be critical to success. Potential importation delays can also be problematic, but with good planning they can be avoided.

Rig selection will be influenced by the strength of offshore currents, environmental requirements and other challenges such as Arctic conditions. In order

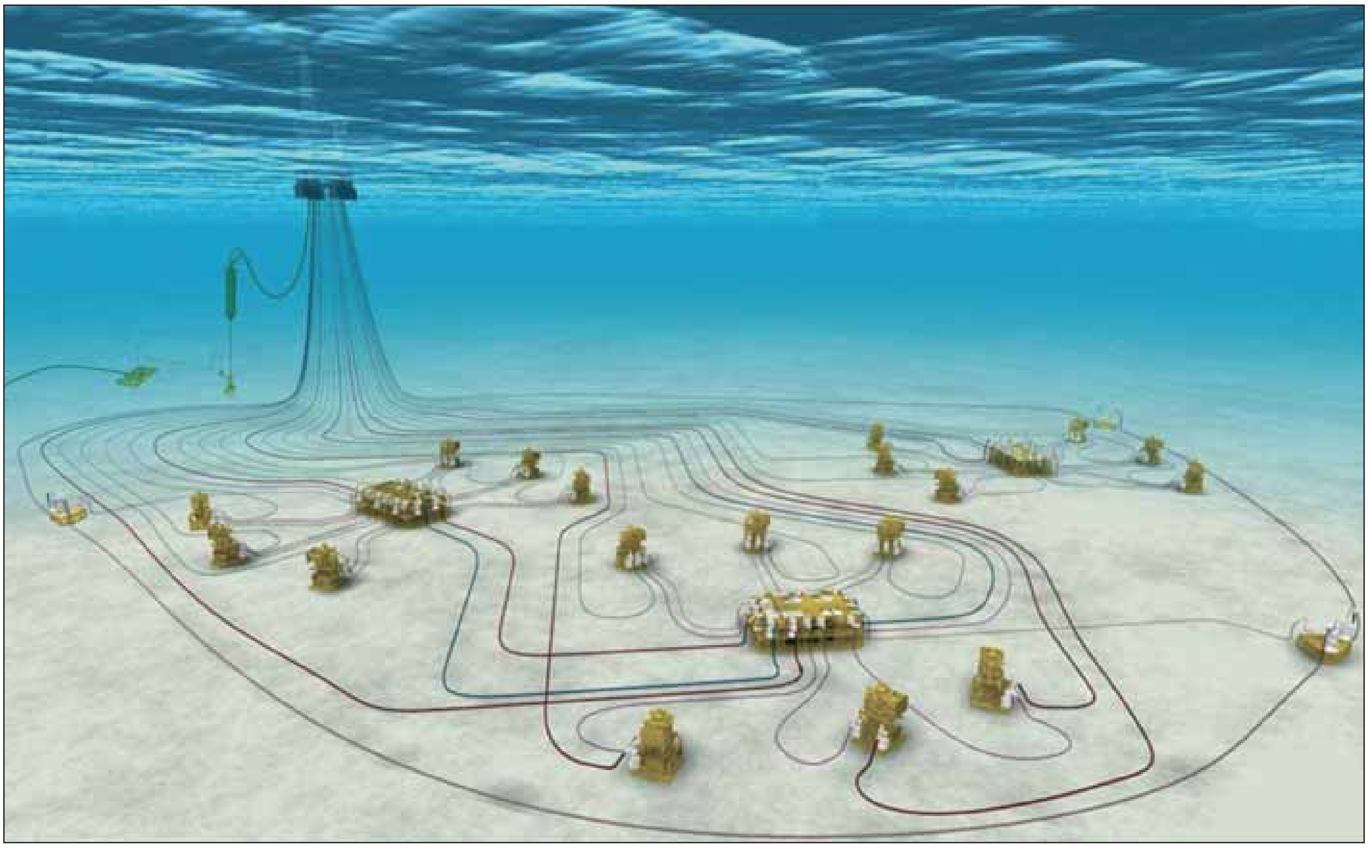

Figure 3 - Subsea Wellhead Production System (Petrobras News Agency)

to ensure rigs will be capable of meeting operating conditions, potential high current studies or the impact of floating ice are carried out. Research will show whether the rig will be capable of maintaining station and whether or not VIV suppression is a requirement. In all parts of the world, environmental considerations are important, and if not properly addressed, delays in obtaining a drilling permit can result.

Health, Safety and Environment (HSE) and Drilling Performance

From a safety and environmental standpoint, drilling will be completed without significant environmental damage, while a measurement of a safety 'Day Away From Work Case' (DAFWC) will be recorded and will highlight the importance of conducting proper risk assessments. Performance will be measured and key criteria assessed such as days per ten thousand feet and Non-Productive Time (NPT).

Deepwater Development

Poised to produce hydrocarbons in waters reaching 10,000 ft (3,049 m), the industry is certainly not standing still regarding deepwater. The future is clear. Many billions of barrels of oil and gas reserves lie in deep, 3,280 ft to 8,200 ft (1,000 to 2,500 m), and ultra-deepwaters 8,200 ft+ (2,500 m+). As the industry looks to production in 10,000 ft (3,000 +m) water depth, we consider two key questions: what are the unique considerations for deepwater developments and what special technologies are required for production[14].

Water Depth[15]

What really differentiates and impacts deepwater activities are the challenges associated with incredible sea depths. Of course, block size in deepwater frontier areas such as Brazil can reach huge proportions; for example, 25,000 sq km (that's 1,000 GOM blocks). This makes picking and drilling prospects tough, irrespective of operator resources or experience; however, it is greater water depth that leads to higher pressures and overburden and that's where the problems arise. The drilling engineer has to consider and overcome bottomhole pressures that can exceed 22,000 pounds per square inch (psi) (1515 bar) and drilling fluid line temperatures that can fall below 0°C (32 °F).

Figure 4 - Arctic Rig The Northstar Island (BP)

So where is the deepwater line drawn? According to Petrobras, waters between 3,280 ft to 6,560 ft (1,000 m to 2,000 m) depth are classified as 'deep'. Beyond this are the ultra deepwaters which are about 11,480 ft (3,500 m) for the present. Definitions aside, deeper seas mean deeper pockets[16].

Deepwaters are characterised by strong currents, which create a need for high-specification rigs that are capable of maintaining station and in some instances of suppressing VIV. Such rigs are expensive. Contracting one in the GOM can cost a cool US $500,000 per day or more.

Under Pressure

Deepwaters are also characterised by young depositional formations that differ from shelf and onshore scenarios. Exemplifying this is the typically narrow window between PPFG. Low fracture gradients can necessitate lighter drilling fluids and lighter cement slurry, while rising pore pressures can often upset the delicate fracture gradient destabilising the well-bore and jeopardising the section, if not the entire well.

A consequence of a narrow PPFG window is the need for close tolerance and contingency casing schemes to isolate formations. In short, deepwater operators must have an excellent knowledge of well bore stability to avoid a formation influx (kick) or a fracture of the casing shoe, which would result in losses. New well construction methods, such as the 'dual gradient system', are being developed for such an eventuality. Oil companies are presently sponsoring a Joint Industry Project (JIP) that develops a subsea pump to control the pressure at the wellhead and study gas injection systems. For this technology to work, risers must be resistant to collapse forces as soon as gas is injected into their bases[17].

Temperature Gradients

Further engineering challenges are added by temperature gradients. A negative gradient runs from surface to

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seafloor, but this turns positive below the mud line. Equations become more complicated as cooler surface mud alters the temperature profile as it is pumped downhole, while gas hydrate formation is a common problem that is difficult to resolve. Hydrates trap natural gas inside water molecules and bond with metal. This can result in tubing blockages which affect the valve and Blowout Preventer (BOP) operation. Unfortunately, deepwater environments present the ideal combination of low temperatures, high seabed pressures, gas and water that cause hydrate formation. Extensive modelling is required to minimise hydrate formation. Low temperatures alter the properties of cement which mean new designs of cement slurry composition are required. Existing American Petroleum Institute (API) norms do not cover low deepwater temperatures and stringent test procedures are now determining the properties of cement slurries in deepwater operating conditions[18].

Riser Manipulation

Riser manipulation is another challenge found in ultra deepwaters and beyond. Research is being carried out on innovative lightweight risers. By reducing the weight of the risers and their joints, it should be possible to use lower cost fit-for-purpose rigs in ultra deepwater. A parallel technology that has been developed is the 'slender well' concept to permit the use of smaller diameter well bores and lighter risers.

The constant development of new subsea equipment is a must in order to meet new water depth challenges while keeping costs low.

Major limitations associated with ultra deepwater developments which are associated with very expensive day rates include high installation loads of subsea equipment and high flow rate subsea wells. 'Drill-pipe risers' have been used to perform completions and workovers at water depths reaching 6,860 ft (2,000 m) and, although they are far more efficient than conventional risers, control umbilicals and hang-off equipment presented problems in 10,000 ft (3,000 m) water depths.

Control umbilicals require careful handling, particularly during the tubing hanger mode when the hanger has to be deployed inside the marine riser.

Mooring mechanisms that will function in greater water depths are also a challenge. Design software must be able to check a specific mooring system's calculations and determine the validity of truncated scale tests as well as modelling mooring systems.

Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

Extended Reach Development (ERD) wells are being successfully drilled in deeper waters. ERD wells offer the ability to reach complex targets and present good thermal flow pipeline properties which are important in deepwater scenarios due to negative temperature gradients. Widely spaced reservoir targets can be tapped using a single well bore, thereby reducing environmental impact and well construction costs. Because less heat is lost through the pipeline, average flow temperatures are kept higher which reduces hydrate and wax formation and ultimately maintains production rates. Alternatively, costly heated subsea pipelines are required.

Intelligent completions are improving hydrocarbon production from both ERD and multilateral wells. With the emphasis on reservoir management to optimise performance and maximise recovery, the likelihood for costly well intervention is reduced. Coupled with this is the deepwater gas lift optimisation project, which addresses the software, equipment and automated processes required for gas lift design.

Deepwater subsea completions often present major problems, especially with the completion riser. As a result, a lightweight composite drilling riser joint is being used with conventional risers up to 2,300 ft (700 m) water depth. More research is necessary, but results have been promising. Production risers, subsea wellheads and other production equipment designed specifically for deeper water depths and differing rig types are just some of the technologies being developed[19] (see Figures 2 and 3).

Deepwater Flow Assurance

Companies are developing inter-related technologies capable of predicting and preventing subsea flow lines and pipelines from getting blocked. The technologies here range from low-density foam cleaners to mechanical pigs to tractors for wax or hydrate plug removal.

Arctic E & P

Arctic E & P is a term that is generally applied to fields that are located within the Polar or Arctic Circle which extends from Russia, Finland, Sweden, Denmark, Norway, Canada and Alaska (US). In Alaska, where the exploration is predominantly on land, getting access to the tundra locations is actually dependent on ice and snow cover so as to avoid damage to the permafrost. This territory also covers offshore areas such as the Sea of Okhotsk, Sakhalin Island, the Beaufort Sea and the Barents Sea.

Antarctica is the third-smallest continent after Europe and Australia; 98% of it is covered in ice and is bound

Pre-planning for HTHP wells can greatly benefit the operator in terms of drilling performance, but also in conventional as well as non-conventional well control operations.

not to be developed until 2048 and therefore is not considered. The call for an environmental protocol to the Antarctic Treaty came after scientists discovered large deposits of natural resources such as coal, natural gas and offshore oil reserves in the early 1980s.

As one would expect, offshore Arctic E & P is heavily constrained by harsh weather conditions. The offshore Arctic is characterised by the ice period during which time no operations can take place. Exemplifying this is the Sea of Okhotsk which is routinely subjected to dangerous storm winds, severe waves, floating ice, icing of vessels, intense snowfalls and poor visibility. The average annual extreme low ranges between -32°C (-25.6 ºF) and -35°C (-31ºF). Ice sheets up to 5 ft (1.5 m) thick move at speeds of one to two knots. Operations in the Barents Sea need to contend with drifting sea ice, icebergs and long transportation distances[20].

Offshore structures can be exposed to icing from October through to December and the ice period extends for six months. It is only during the following six months, or the ice-free period, that operations can take place. Even so, wave heights range between 3 ft and 10 ft (1 m and 3 m) and strong winds can cause even higher waves during the ice free period.

To combat such extreme conditions, operators must use beefed-up rigs and facilities. In the case of the Sakhalin development, engineers reconditioned the Molikpaq, an Arctic offshore drilling unit originally designed for use in the Beaufort Sea in North America, where ice conditions are more severe than offshore Sakhalin Island. The Piltun Astokhskoye field is developed by the Vityaz Production Complex. This consists of the newly refitted Molikpaq, a Single Anchor Leg Mooring (SALM) 1.25 mile (2 km) away and a Floating Storage and Offloading (FSO) vessel[21].

Technical and environmental experts reconditioned the Molikpaq so that it could handle pack ice, temperatures, and strong waves in the Sea of Okhotsk. The Molikpaq required substantial modification to convert it from a drilling platform to a drilling and processing platform and it was towed 3,600 nautical miles (6,670 km) from the Beaufort Sea to the Okpo yard in South Korea. The redesign included major rig modifications including raising the height of the drilling unit by 16.4 ft (5 m) to create space for the wellheads and increasing the eight conductor slots to thirty-two. Cumulatively over seven work seasons since the first oil in 1999, the Molikpaq has produced over 70 million barrels (MMbbl) of oil.

HTHP

HTHP wells are generally considered to be those which

As pressure drops due to friction are proportional to fluid viscosity, the only phase that is sheared at the wall is water; therefore, the obtained pressure drop is almost the same as if only water flow was involved.

encounter bottomhole temperatures in excess of 300°F (150°C) and pressures which require a mud weight of 16.0 ppg (1.92 SG) or more to maintain well control. Another way to consider pressure is to note that standard downhole tools and equipment are rated at 20,000 psi (1,361 bar) anything above this is considered high pressure.

Many offshore regulatory authorities require some sort of emergency plan be in place prior to issuing the drilling permit. In addition to the company's standard emergency plan, many operators have a Blowout Contingency Plan (BCP) that specifically covers well control events such as:

- Immediate response activities
- Emergency organisation
- Well capping and killing procedures
- Specialised well control equipment
- Hazardous fluids such as H_2S and CO_2
- Logistics, and
- Relief wells.

Pre-planning for HTHP wells can greatly benefit the operator in terms of drilling performance, but also in conventional as well as non-conventional well control operations. The pre-planning should include detailed well design engineering and HTHP awareness training.

Connections that lose their integrity impact numerous HPHT development and production operations worldwide and are responsible for huge costs as they can lead to stuck-fish, lost-in-hole and even sidetracks[22].

Salt Challenge

Prevalent worldwide, massive salt sections add to well construction challenges.

Several deepwater blocks in the GOM, West Africa (Congo Basin) and Eastern Brazil (Santos Basin) are characterised by salt provinces; for example, sub-salt wells have been drilled with total depths exceeding 30,000 ft (9,146 m) and salt sections exceeding 8,000 ft (2,439 m) in thickness.

Production companies who hold sub-salt acreage face a combination of imaging and deepwater drilling problems. Other operators in deepwater areas, such as West Africa and Brazil which have had relatively limited salt challenges to date, also need sub-salt strategies as exploration reaches salt provinces. In some cases, spanning over half a well-bore's true vertical depth, salt can present sizeable difficulties.

Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

Where salt is just 'salt', things are relatively simple; but, where salt sections are heterogenous containing halite, anhydrite, sedimentary channels, flows or rubble zones, things become complex. This makes the mapping and imaging of salt a difficult process with subsurface phenomena often going unseen. Seismic data cannot always represent salt flows or channels with many anomalies only truly characterised through drilling.

Anomalies, represented or not, create drilling problems that range from loss scenarios with pore pressure regressions below salt, loss of directional control, stuck-pipe due to salt closure and destructive vibration induced by alternating salt/sediment bedding[23].

Hole stability can be affected by active salt tectonics. Intermediate sections can be subjected to geo-hazards such as faulting and fluid seepage. Salt closure increases the loads on the casing and its cement as both must be able to withstand the forces applied by the salt as it expands radially and pinches the well. Simultaneously drilling and casing the well may be a good way of overcoming this. Maintaining directional control in salt is not straightforward as there is a tendency for well-bore deviation.

Certain salts require higher weight-on-bit to drill compared with sediments.

Consequently, the higher weight-on-bit, the greater the tendency for the bottomhole BHA to build inclination.

Costly deep-water rig rates mean that operators are right to require high performance levels. Consequently, more rigorous Quality Assurance/Quality Control (QA/QC) standards are demanded of downhole tools to permit sections to be drilled in single runs at high penetration rates. Salt sections have higher fracture gradients (when compared with sediments located at the same depth) enabling longer sections and reduced well-control problems associated with permeable formations. Predicting PPFG in sediments below the salt, however, is tricky. Pressure regressions below the salt often dictate casing depth.

It is known that Synthetic Oil-Based Mud (SOBM) can be the most effective salt drilling fluids as they avoid borehole enlargement and well-bore instability.

Although many risks associated with salt can be reduced through pre-drill seismic, look-a head tools and real-time pore pressure profiling, there are still plenty of 'unknowns' to keep everyone excited.

Heavy Oil

Although large volumes of heavy and high viscosity oil have been discovered worldwide, both onshore and offshore, economic production is a challenge for the oil industry. Increased oil viscosity means increased E & P costs as well as higher refining costs. The definition and categorisation of heavy oils and natural bitumens are generally based on physical or chemical attributes or on methods of extraction. Ultimately, the hydrocarbon's chemical composition will govern both its physical state and the extraction technique applicable.

These oils and bitumens closely resemble the residue from crude distillation to about 538ºC (1,000°F). If the residue constitutes at least 15% of the crude, it is considered to be heavy. This material is usually found to contain most of the trace elements such as sulphur, oxygen, nitrogen and metals such as nickel and vanadium.

A viscosity-based definition separates heavy oil from natural bitumen. Heavy oil has a rating of 10,000 cp (Centipoise) or less and bitumen is more viscous than 10,000 cp. Heavy crude falls in the 10°-20° API range inclusive and extra-heavy oil less than 10° API.

Most natural bitumen is natural asphalt (tar sands or oil sands) and has been defined as rock containing highly viscous hydrocarbons (more than 10,000 cp) or else hydrocarbons that may be extracted from mined or quarried rock.

Other natural bitumens are solids, such as gilsonite. The upper limit for heavy oil may also be set at 18°API, the approximate limit for recovery by waterflood.

The industry reference for offshore heavy oil production is the Captain Field which is operated by ChevronTexaco and located in shallow waters in the North Sea.

Brazil, Canada, China and Venezuela are just some of the countries that hold significant heavy oil volumes within the 13° API to 17°API range. Some of the heavy oil fields are located in shallow waters, which simplifies appraisal and development strategies, while others are in deepwater, which adds complexity.

New production technologies are required for the economic development of offshore heavy oil reservoirs. Long horizontal or multilateral wells, using high power pumps such as Electrical Submersible Pumps (ESPs), hydraulic pumps or submarine multiphase pumps, could partially compensate for a decrease in productivity caused by the high oil viscosity.

Additionally, flow assurance could be improved with insulated or heated flow-lines, or alternatively, with the use of water as a continuous phase system. Heavy oil processing in a Floating Production Unit is not straightforward and new separation technologies, as well as the feasibility of the heavy oil transportation with emulsified water, needs to be investigated. The existence of light oil reserves in neighbouring reservoirs, even in small volumes, will play an important role in this determination.

Reservoir Technologies for Offshore Heavy Oils

Heavy oils are difficult to produce. From a reservoir standpoint, increased viscosities impair the flow of oil while in an offshore environment traditional enhanced recovery methods are often limited. Most of the heavy oil reservoirs in offshore Brazil, for example, are found in non-consolidated deepwater reservoirs. Potentially heavy oil cold production, caused by natural depletion or water-flooding, seems to be a practical option.

It is known however, that the displacement of oil by water is much less efficient than by using 'regular' viscosity oil. Petrobras' research on reservoir technologies for heavy oil production concentrates on the following topics:

- Flow through porous media, which can be used to improve methods for understanding the relative permeability of water and heavy oil in non-consolidated, heavy oil bearing formations
- Modelling of oil varietals in offshore heavy oil reservoirs
- Optimised heavy oil field development
- Modelling to minimise remedial workovers, and
- Fundamental reservoir simulation studies in order to optimise the design of offshore production systems for heavy oils.

Flow Assurance for Heavy Oil

In terms of physical properties, heavy oil differs considerably from lighter crudes, generating a need for new production techniques. Higher viscosities, gravity and pour point combine to make fluid flow through pipelines more difficult than for lighter oils. Higher viscosity also means higher pressure drops and the need

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for more powerful pumps and pipelines with higher pressure ratings. Increased oil gravity also increases the pressure gradient in upwardly flowing pipelines such as the wellbore and riser.

These issues become more important in deepwater fields as low pour points can create flow assurance concerns in the case of 'cold start-up' of pipelines or wells.

Core annular flow is being developed to flow through pipes. The idea is to use water to reduce pressure drops. Water is added in an annular flow pattern so that oil is kept at the centre of the pipeline while the water maintains contact with pipe walls. As pressure drops due to friction are proportional to fluid viscosity, the only phase that is sheared at the wall is water; therefore, the obtained pressure drop is almost the same as if only water flow was involved. This reduction in pressure drop for heavy oil can reach a magnitude of a thousand. This technology has been used already for onshore oil export pipelines and is now under development by Petrobras to be used in offshore production systems including well bores, pipelines and risers in the presence of gas.

Emulsion behaviour is an equally important issue for heavy oil production. Emulsion is a fine dispersion of two liquid phases and is generated when the fluids mixed together shear. There are also other techniques that can be used to reduce fluid viscosity and pressure drops; for example, heavier crudes can be diluted with lighter ones. Another example is the generation of an inverse emulsion (oil in water) using chemicals. Flow assurance is another concern for heavy oil production. Wax deposition and crystallisation may occur and create pour-point problems to an already viscous fluid. Also, hydrates can form in heavy oil systems creating an even more viscous slurry which may clog pipelines.

The existence and characterisation of tarmac beds, sometimes present at the bottom of the heavy oil zone close to the oil water contact, is extremely important. Limited connectivity of the bottom aquifer with the oil zone would avoid rapid increases in water coning. This would make for more efficient water injection and could radically change a development scheme.

Many issues still merit research and oil companies are pursuing both laboratory and field based technology[24].

Now that we have outlined the extreme E & P challenges faced by the industry and the difficulties faced when trying to add new reserves, we need to re-examine our thinking about the existing or mature fields that are currently in use. How do we ensure the highest recovery of oil possible? How can we improve production? The next chapter answers these questions by examining the various ways in which we can make the most of our existing assets.

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4. These types of contingencies can rapidly increase the costs of deepwater wells. See also RP 54. Occupational Safety for Oil and Gas Well Drilling and Servicing Operations. Includes procedures for promotion and maintenance of safe working conditions for employees engaged in rotary drilling operations and well servicing operations, including special services. Applies to rotary drilling rigs, well servicing rigs, and special services as they relate to operations.

5. Notes from Arctic drilling expert John Lewis ASRC.

6. Harts E & P May 2003 Drilling Column "Razor sharp drilling'. Simplify wells.

7. Notes from Arctic drilling expert John Lewis ASRC.

8. Petrobras Technology Bulletin 2006.

9. Petrobras Technology Bulletin 2006.

10. Petrobras E & P Technology Harts E & P.

11. Enhanced Oil Recovery, Textbook Vol. 6. by Don W. Green and G. Paul Willhite ISBN: 978-1-55563-077-5, Society of Petroleum Engineers 1998.

12. Petrobras Technology Bulletin 2006.

13. Personal experience of BP's drilling of Rebeca and Reki exploratory wells offshore North West Brazil.

14. As well as service company input.

15. See Petrobras E & P Technology Harts E & P PROCAP section.

16. Along with water depth the distance from shore or facilities will dictate costs.

17. Harts E & P Dec 2002 Drilling Column 'Deepwater faces its own challenges'.

18. See Petrobras Technology Bulletin June 2006.

19. API TR1 Cement Sheath Evaluation Provides the current principles and practices regarding the evaluation and repair of primary cementations of casing strings in oil and gas wells. Cement bond logs, compensated logging tools, ultrasonic cement logging tools, and borehole fluid-compensated logging tools are covered.

20. See Petrobras PROCAP 3000.

21. StatoilHydro Barents Sea E & P.

22. In 2007 Sakhalin Energy produced above 12.4 million barrels of oil from the Molikpaq platform. This exceeded the 2006 production by some 800,000 barrels.

23. API Bull 5C2 Performance Properties of Casing, Tubing, and Drill Pipe Covers collapsing pressures, internal yield pressures, and joint strengths of API casing, tubing, and drill pipe.

24. Harts E & P Mar 2004 Drilling Column Wajid Rasheed 'Salt Challenges'.

25. See Petrobras E & P Technology Harts E & P PROPES section.

26. Idem.

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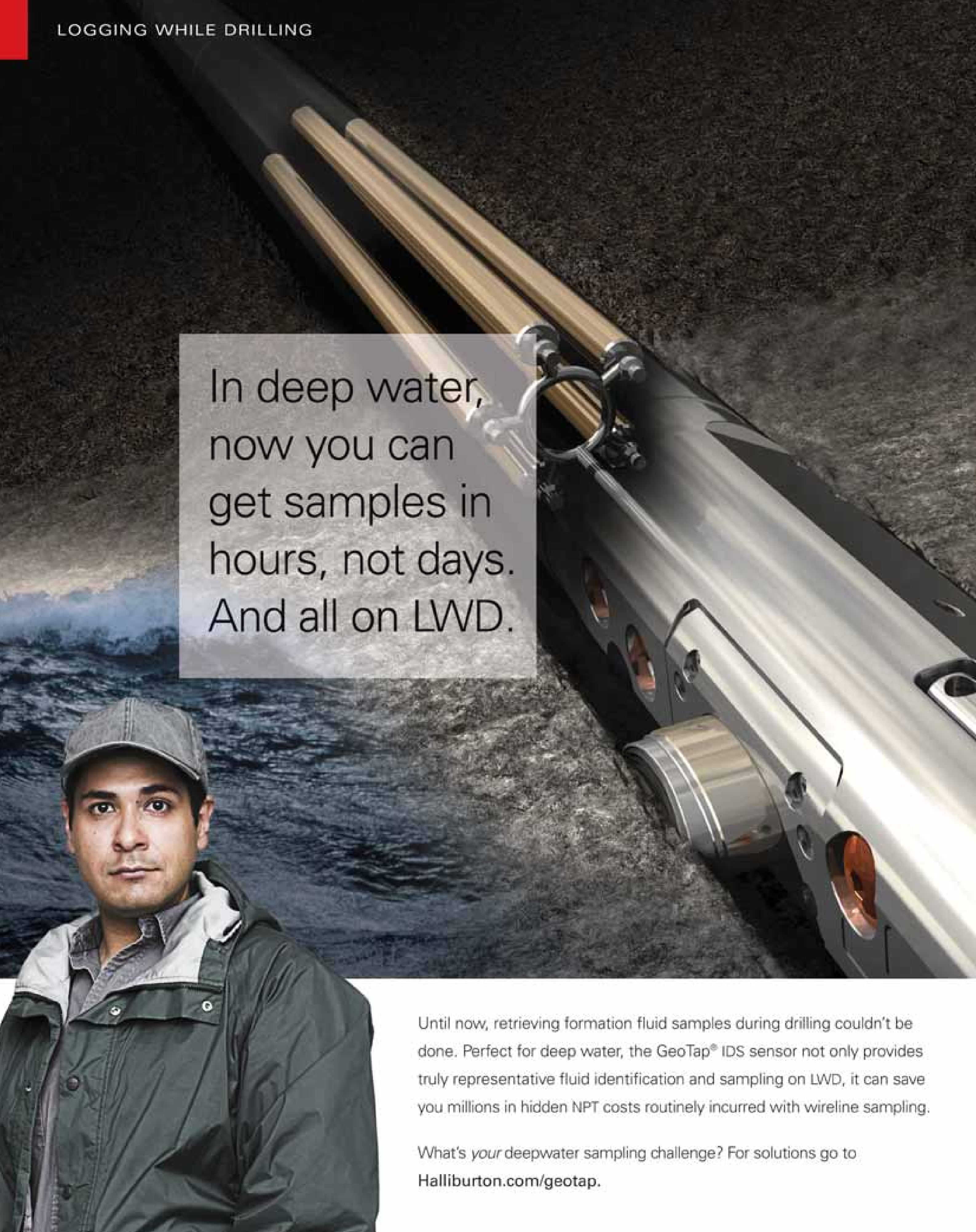
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