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Challenges and New Technologies for the Development of the Pre-Salt Cluster, Santos Basin, Brazil

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Abstract

Pre-salt carbonate reservoirs from Santos Basin represent a great opportunity and probably the most important recent oil discovery. Tupi area (estimated to have recoverable volume of 5 to 8 bboe), which is the most known amongst several other leads in the cluster, is going to be a great insight for the production project.

From the production point of view, this new frontier has technological challenges that are being addressed by PETROBRAS and partners. Special attention is being dedicated to anticipate solutions to potential problems. This will require a balance between innovative and field proven solutions.

This paper addresses the most critical points, where Petrobras is making a great R&D effort, which are:

Well technology, where casing stability, well cost and productivity are addressed, in a scenario of water depths beyond 2,200m, target depths greater than 5,000m, crossing salt layers that can reach 2,000m in thickness.

Poorly known microbial carbonate reservoir, heterogeneous in vertical profile, spread over very large areas, with wettability concerns, requiring careful evaluation of the performance of the waterflooding method and EOR.

Wax deposition, due to low temperature in the ocean bottom, imposing limitations to the subsea layout.

Gas processing and exporting technologies concerning environmental issues: CO_2 compact removal units aiming the minimization of emissions to the atmosphere.

Production units placed in more than 2,000m water depth, with oceanic conditions quite severe and dealing with high CO_2 content stream.

These challenges deserve all Petrobras attention, but also count with the confidence in achieving good technological solutions, supported by the history of successful developments of the company.

Introduction

The history of success built by Petrobras in deep water Brazilian coast – mainly Campos Basin – was largely supported by successive discoveries of heavy oil in turbidite sandstones, step by step towards gradually deeper and deeper water depths (Carminatti *et al.*, 2009). The Pre-salt discoveries of Santos Basin represent discovery of huge volumes of light oil (28 to 30 degrees API), with high gas content, in a very short time span, close the most important consuming centers in Southeastern Brazil, and formation tests in the first wells have presented very high flow rates with no indication of barriers. All are excellent news, although PETROBRAS and partners recognize that the Pre-salt of Santos Basin represents a challenging scenario: ultra-deep water (greater then 2,000 meters), deep carbonate reservoirs (deeper than 5,000 meters), spread over very large areas, with high gas-oil ratio (GOR in Tupi area greater than 200 m^3/m^3), CO_2 content (8-12% in Tupi), high-pressure and low temperature, laying immediately bellow a thick salt layer (more than 2,000 meters of salt), located around 300 km from the coast, with oceanic conditions more severe than Campos Basin. This scenario demands using sometimes present day technology in the limit, and other times, adaption and development of technologies specific for such conditions. This paper addresses the most critical points to the development of production in the Pre-salt of Santos Basin, where Petrobras is making an R&D effort to develop and qualify new technologies, including well technology, reservoir technology, flow assurance, gas processing and exporting technologies, and production units. Additionally, the paper discusses briefly how PETROBRAS has organized its structure to face these technological challenges, including the creation of a technological program – PROSAL – focused on Pre-salt objectives.

Well Technology

In 2006, the ultra-deep water Pre-salt prospect, the exploratory well RJS-628A was drilled successfully though a thick layer of salt in Tupi area, in Santos Basin. The well RJS-628A was located in 2,126m of water and had at about 1,000m of supra-salt section, which was followed by more than 2,000m of salt, according to the illustration presented on Fig. 1. The target was reached immediately bellow the salt, a carbonate reservoir at about 5,200m from the rotary table. Besides successful drilling, the well RJS-628A revealed huge potential for oil production and started a new age for the Pre-salt exploration in Santos Basin.

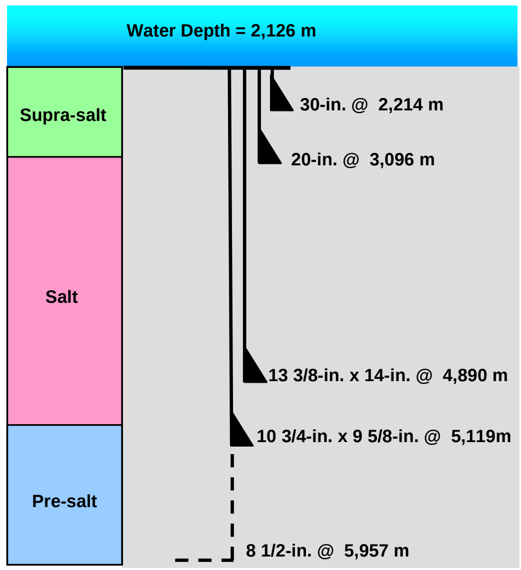

Figure 1 - Casing Program of the Well 628-A

Despite the extremely successful exploratory campaign in that particular area of Santos Basin, the development of Tupi and other leads already discovered in the same Pre-salt area will demand to surmount many challenges associated with well construction. The presence of such thick salt section usually creates favorable conditions for trapping hydrocarbons, which is a positive feature in terms of exploration. In contrast, the associated downside is the extensive list of potential operational problems for successfully constructing the well drilling through that thick salt rock, such as stuck pipe, casing collapse, poor cement performance, etc.

Drilling that evaporite layer is particularly difficult due to the fact that the rock is composed of different types of salt with different creep rates. Halite (NaCl) and anhydrate ($CaSO_4$) are predominant, but layers of carnallite ($KMgCl_3{\cdot}6H_2O$) and tachydrate ($CaMgCl_3{\cdot}12H_2O$) are also present and have much higher creep rates than the formers. The viscous-plasticity of the salt rock (Poiate *et al*., 2006; Costa & Poiate Jr, 2008; Falcão, 2008) is responsible for wellbore closure as a function of time, creating significant difficulties for well construction. Fortunately, the temperature of the salt layers, which is one of the most important parameters in terms of exerting influence on the creep behavior, is not higher than 64ºC (147ºF) in Tupi and surrounding areas, meaning that creep rates are significant lower than in other locations where temperatures are higher. In addition to being a function of overburden pressure and temperature, the rate of salt flow is also influenced by how it is bedded with other formations and its composition, which is a quite complex subject in this case considering the different types of salts involved.

In practical terms, the experience developed, so far, drilling vertically through those thick salt layers in Tupi and nearby fareas shows that the wellbore closure process is not so fast that could cause severe operational troubles. However, despite that encouraging practical experience, well closure may happen and cause, later on, severe problems with casing failures in front of the salt, which is a well documented phenomenon in literature (Cheatham Jr. and McEver, 1964; Pattillo & Rankin, 1981; Goodwin, 1984; Rike *et al*., 1986). Probably, casing collapse is the main concern related to the development of the Pre-salt areas, which demands the construction of wells with preserved structural integrity for at least 25 years.

The severe effects of nonuniform casing loading caused by salt movement are significantly amplified where the borehole has an irregular shape or is especially tortuous, which can be a result of drilling process or chemical interaction with drilling fluid. It is also important to emphasize that successful well construction requires the achievement of proper cement fill of the annular space. In reality, an adequate cement placement opposite an openhole zone is always a key issue for properly constructing a well. However, it is even more important when dealing with a salt section because the consequences of failure are almost certainly much more detrimental. If the annular space between casing and salt is not filled properly with cement, bending of the casing can occur as salt flow tends to close the borehole (Fig. 2). Further, if cement placement results in only a partial sheath around the casing (Fig. 3), subsequent movement of the salt will probably force the pipe to flatten.

Consequently, it is extremely important to have a strict control on caliper and tortuosity during drilling salt, reducing the chances of having posterior problems related to casing collapse. In addition to controlling well trajectory and caliper, the choice of the drilling fluid, selection of the cement slurry, design of the cement operation, and proper casing design and centralization are vital themes and demand special care.

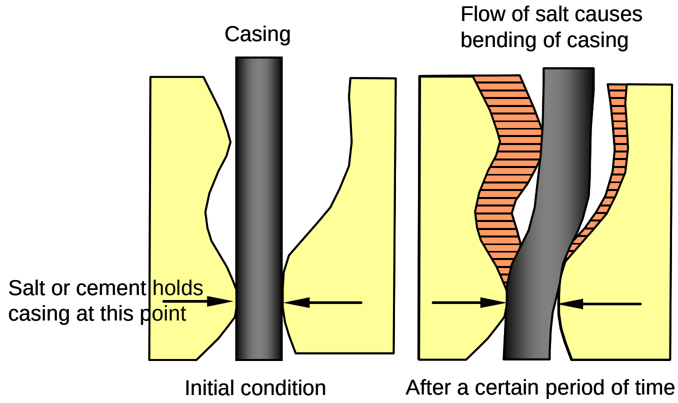

Figure 2 - Bending of Casing (Cheatham Jr. & McEver, 1964)

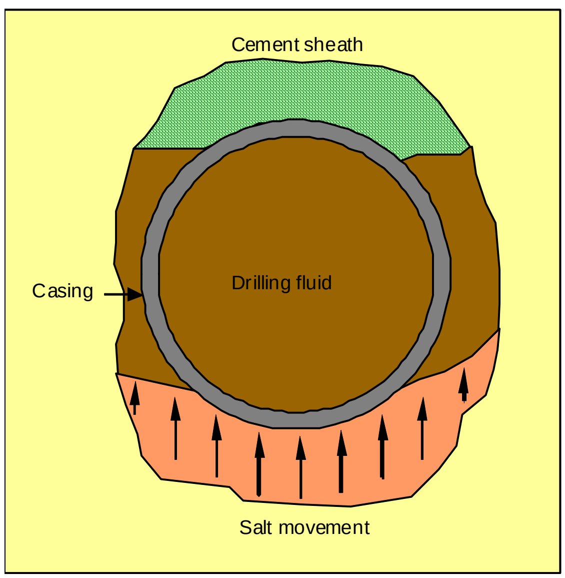

Figure 3 - Nonuniform Load on Casing Caused by Salt Movement (Cheatham Jr. & McEver, 1964)

Another pertinent challenge related to the development of Pre-salt areas consists of constructing deviated wells into thick salt layers. Evidently, all concerns about well integrity presented above have to be particularly considered for deviated wells (Pattillo & Rankin, 1981). However, it is worth to mention that literature extensively documents one possible remedial action for treating complicated casing collapse scenarios. It consists of running a liner inside the casing opposite the problematic formation and cementing the annulus between the two casing strings (Burkowsky *et al.* 1981; Pattillo & Rankin, 1981; Marx & El-Sayed, 1985; El-Sayed & Khalaf, 1987). Under these conditions, it is possible to relieve and uniformize loading due to salt motion, avoiding collapsed casing with consequent shutting down and even loss of the well. Besides the problems associated with casing collapse, as salt is usually harder to drill than other sediments at the same depth, the hardness of the salt not only impacts the rate of penetration (ROP), but also makes directional control difficult. Then, drilling requires high weights on bit, which may cause angle building problems (Whitson & McFayden, 2001).

As the carbonate reservoir rocks use to be heterogeneous, frequent well interventions may be required for restoring the productivity. If this scenario is confirmed based on the analysis of the extended well test (EWT), the use of dry completion for production development may be more attractive than subsea completion, meaning that the construction of extended reach wells (ERW) will be mandatory. Although the widespread experience with extended reach drilling (ERD), construction of

ERW through thick salt layers is relatively rare. In Dieksand (Sudron *et al.*, 1999), driven by laws protecting an environmentally sensitive area, field development demanded the construction of ERW intersecting a salt dome with an 82º slant section. However, in Dieksand, the true vertical depth of the reservoir is slightly deeper than 2,000m, which is significantly shallower than in the Pre-salt (Fig. 4), which shows the industry ERD envelope, presents the comparison between Dieksand and the most extreme ERW that could be constructed in Tupi. As the envelope does not consider the existence of thick salt layers, the actual departure for Tupi is supposed to be shorter than 6,500m (see Fig. 4).

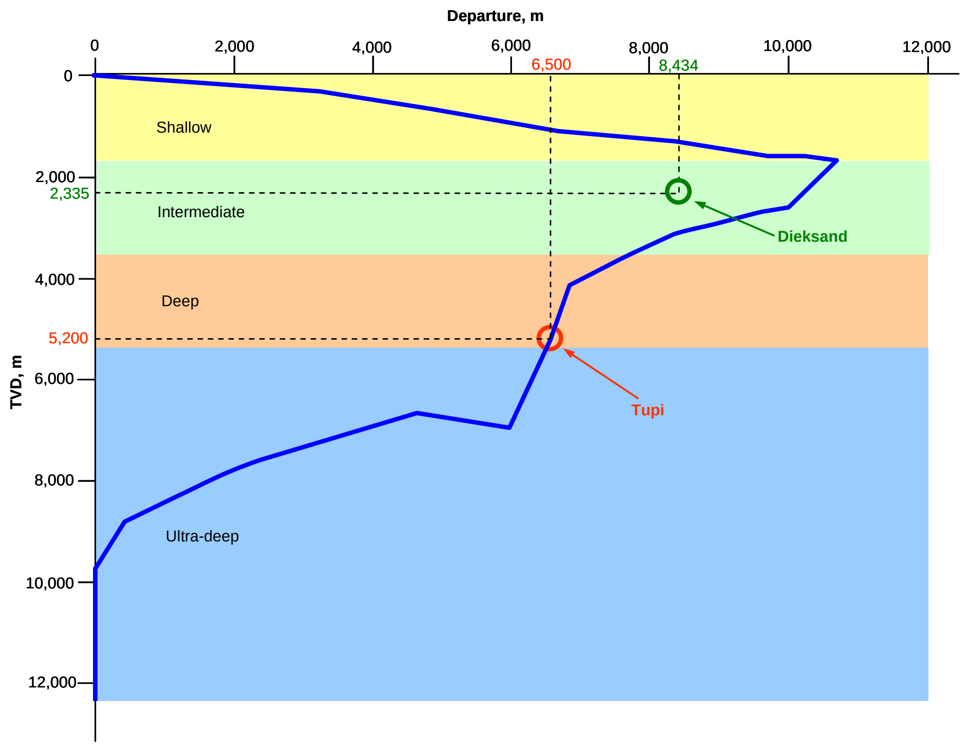

Figure 4 – ERW Drilling Envelope (Robertson, 2006)

In addition to all those challenges associated with the well geometry intersecting thick salt layers, two other subjects are extremely relevant for the scenario: (1) improving penetration rate into the reservoir for reducing drilling costs; and (2) developing an optimum stimulation strategy for constructing high productivity wells, despite reservoir heterogeneity.

As the cost to drill a well is extremely significant in the Pre-salt scenario, it is quite important to improve penetration rate, which becomes progressively more considerable with increasing depth. The reservoir rock is deeper than 5,000m and is hard, resulting in low penetration rates. Certainly, improving drilling process and increasing rate of penetration (ROP) will lower the cost to drill a well. Consequently, it is important to carefully analyze offset wells to benchmark current performance and develop an optimization plan, identifying key areas for enhancement. This particular initiative includes the investigation of depth based drilling data, logging data and daily drilling reports from offset wells. The use of specific bits, bottom hole assemblies (BHA) and best operating practices to improve penetration rate are also part of the efforts.

Besides reducing construction costs, it is also extremely relevant to improve well productivity to create a more favorable scenario in terms of developing the production from the Pre-Salt areas. The best geometry for intersecting the reservoir, vertical, inclined or horizontal, is one of the required designations, which will be, almost certainly, answered by the Extended Well-Test and the Production Pilot (Formigli *et al.*, 2009). Anyway, different approaches are considered to stimulate the wells, such as acid treatment, hydraulic fracture, acid fracture, or the construction of multiple hydraulic fractures (Neumann *et al.*, 2006). However, the definition of the best strategy for stimulating wells demands the creation of significant knowledge about the reservoir, which is being built in line with the discussion presented bellow, in Reservoir Technology.

Further, it is worth to mention that the use of intelligent completions will play an important role in the development plan because the ability to remotely monitor and control individual intervals or entire wells will bring the benefits of reducing well interventions and optimizing production. The combination of efforts with the suppliers is necessary to develop equipment with the appropriate functionality and reliability. One of the main challenges consists of dealing with a corrosive environment, as discussed bellow, in Materials Selection and Corrosion Control Challenges, which may cause severe damage to those downhole devices.

Besides PROSAL, the Company is carrying out other initiatives to present answers to all technical demands associated to the production from the Pre-Salt. In terms of well construction, there is also another program, known as PACAP, which focus on accelerating the learning curve (Bastos *et al*., 2009) related to the introduction of operational activities that were out of the PETROBRAS regular drilling scenario (Carminati *et al*., 2009), but are, actually, becoming extremely relevant from now on.

Reservoir Technology

Pre-salt reservoirs are Cretaceous (Aptian) carbonate rocks, including coquinas and other lithologies of the rift phase bellow microbial carbonates of the sag phase, just bellow salt, partially dolomitized. Sag microbial carbonates seem to be nearly flat in seismic sections, but well data indicate high vertical heterogeneity in permeability. Formation tests in sag carbonates have presented very high flow rates with no indication of barriers, and seismic maps indicate huge structures (rift deposits have not been tested to the moment).

These formation tests are preliminary results, since there are still few wells, and the first extended well test (EWT) is scheduled for april-2009. This EWT will investigate the sag carbonate reservoir. It will be implemented in parallel with the exploratory appraisal campaign and intends to evaluate the long term production behavior of the wells and the reservoir, as well as the fluid lift and flow assurance. The production Pilot System (five producers, two water injectors and one gas injector) in Tupi lead will investigate primary production, waterflood and gas injectivity in sag reservoir. First oil of the Pilot Phase is scheduled for late 2010. This project will anticipate production and injection information, resulting in a better understanding of the secondary recovery mechanism and reducing the risks of the future development systems (Marcusso *et al*., 2009; Formigli et al., 2009).

The knowledge about reservoir properties at the moment is incipient, and the main challenge now is to build the best models, projects and predictions with the data available. Challenges in reservoir technology in Pre-salt of Santos Basin can be classified into three main categories: (1) describing and representing reservoir fluids and rock heterogeneities, (2) choosing the best production strategy according to the reservoir characteristics, and (3) predicting reservoir performance in the future.

The predominant reservoir type (microbial carbonates), poorly known around the world, is the first challenge, and is demanding studies in order to try to identify possible analogues, considering both geometry of heterogeneities and dynamic aspects.

Present seismic data have given excellent results in structural imaging, but imaging of heterogeneities can be improved. To continue drilling high productivity wells, necessary to guarantee economic projects in ultra deep water scenario, besides engineering concerns, the conceptual reservoir model must be tested and continuously refined. The main, large scale heterogeneities in rock properties, as well as smaller scale, internal reservoir heterogeneities, must be represented. These are the basic requirements to place the wells in the best reservoir portions, to choose the best well concept – including geometry, spacing and completion strategy, optimizing the production strategy. Reservoir heterogeneities may impact decisively primary production, waterflood and EOR methods. One of the biggest challenges is how to represent most important heterogeneities in reservoir simulation models, and take advantage of that knowledge. Although initial geologic models have been tested successfully, microbial carbonates are a new play, with sparse production history. High sonic interval velocities in the carbonates reduce seismic resolution. Either structural complexity of the top of the salt, or internal structural complexities within the salt layer, may result in non homogeneous spread of seismic energy through the Pre-salt reservoir. The consequence may be a non homogeneous illumination of the reservoir. Reprocessing old seismic data, acquiring and processing new data are important challenges to produce the best reservoir images, improve reproduction of petrophysical reservoir properties and the potential for identification of fluid contacts.

An important point to be addressed in reservoir model is the vertical to horizontal permeability anisotropy ratio: if vertical permeability is too low, for example, horizontal wells may not be a very attractive option if compared to vertical wells. Defining continuity of low and high permeability layers, role of diagenesis, role of fractures and faults, may be critical. This must be a point of attention in the search for analogues to Pre-salt reservoir, both in outcrop, recent deposits and field examples, as well as in future dynamic data acquisition in EWT and Tupi production pilot, refining reservoir model continuously.

Preliminary reservoir simulations indicate that waterflood may double recovery factor in Tupi lead. Waterflood performance in the sag reservoir is going to be evaluated in the Tupi Production Pilot, which will give key information about sweep efficiency, continuity of high permeability layers, hydraulic continuity throughout the reservoir, behavior of faults, injectivity behavior (damage mechanisms), vertical to horizontal permeability anisotropy ratio, etc. Critical points to that performance may be wettability (neutral, in the first laboratory analyses) and reservoir heterogeneity. The most important technological challenges at this stage are related to a precise evaluation and quantification of the waterflood results in the pilot.

EOR performance is also being evaluated in fluid flow simulations (gas flood and WAG). Preliminary results are indicating excellent results of these methods, considering gas miscibility. In the Tupi production pilot, gas injectivity is going to be tested, as well as WAG. The other very important issue for future decision about EOR is that the local market is strongly demanding natural gas. The high gas-oil ratio brings opportunities in EOR which are closely linked to environmental restrictions and market demands. One challenge will be separation of CO_2 form natural gas in offshore conditions, which may not be an easy task. The development of compact processing floating units for CO_2 separation will be critical in defining the future of EOR in the Pre-salt of Santos Basin. If such plants are not developed, CO_2 may be injected in the reservoir together with natural gas.

At last, the choice of the production unit model – dry completion versus wet completion, which is closely linked to the reservoir model and forecasts. Multiple reservoirs with relatively high vertical heterogeneity, scaling precipitation potential typical of high salinity connate waters, corrosive conditions, potential for organic deposits due to low temperature, etc., indicate some advantages of production units with dedicated workover and drilling rigs. The first production systems are going to be based in the concept of wet completion production units, but efforts are being conducted with the purpose of qualifying, as well as quantifying potential benefits, of dry completion units to the conditions prevailing at the Pre-salt pole of Santos Basin. The idea is making dry completion an option to wet completion in the future.

Flow Assurance

Flow assurance issues can have a significant impact in the development of some Brazil's Pre-salt areas. Wax, inorganic scaling and hydrate plug formation comprise the key concerns in some areas. Considering the combination of these key problems, chemical-products suitability and compatibility appear as an important issue.

Hydrates often represent the most dramatic flow assurance problem for a deep offshore development. During the steady-state production mode, hydrate formation is usually avoided by designing a pipeline insulation that keeps the fluid temperature above the hydrate thermodynamic envelope. But, in case of shutdown, an appropriate emergency control procedure must be applied to prevent hydrate formation, which includes ethanol injection and pipeline fluid replacement. Extensive simulations have been performed to evaluate the maximum untouched time before applying the emergency procedure. The simulations consider not only the thermodynamic conditions but also the hydrate formation kinetic. Depending on the fluid properties and the shutdown conditions, the hydrate formation kinetic can be very slow, which allows longer pipeline untouched time.

Brazilian Pre-salt oils are relatively paraffinic. In contrast to hydrate plug formation, wax deposition occurs slowly, but with similar results if not controlled. The main wax control scheme relies on the same strategy used successfully for years at Campos Basin: pipeline insulation together with an adequate pigging program. For Tupi lead, PETROBRAS does not foresee major challenges due to wax deposition. In more critical areas, chemical inhibition can be applied to minimize the wax deposition when the fluid temperature falls below the wax appearance temperature. The effectiveness of the paraffin treatment is dependent on the crude oil composition, inhibitor chemistry, inhibitor concentration, and the production conditions. A thorough laboratory screening has been carried out to identify proper inhibitors for each of the subsalt oils. Products for deepwater subsea injection must remain solid-free at all conditions of temperatures and pressures throughout the umbilical lines.

In at least one of the pre-salt leads PETROBRAS may face start-up problems in pipeline transportation due to oil gelification process after a period of shutdown. The warm crude oil may be cooled below its pour point when the flow in a deepwater pipeline is shut down; forming a gel consisting of deposited wax crystals in a viscous matrix. A series of laboratory experiments have been performed to evaluate the gel strength and simulate a feasible start-up procedure for the pipeline containing gelled Pre-salt crude oils. Given the expensive of highly insulated systems, and the risks associated with unsatisfactory chemical treatment, a clear opportunity rises to develop strategies for allowing oil to flow after a controlled wax deposition. The main issue for considering a cold flow strategy relies on thoroughly understanding the physicochemical properties of wax deposition and deposit growth kinetic.

Extremely high concentration of calcium ion has been identified for most of the subsalt formation waters. Preliminary results from thermodynamic models suggest severe calcium carbonate deposition problems since the beginning of the production, even though the expected watercut is rather low at the early stages. Carbonate scales are formed in the wellbore due to dissolved CO_2 release which causes water pH as well as the saturation index of carbonate minerals to increase. Downhole continuous injection of scale inhibitor is required to avoid carbonate deposition in the wellbore.

Considering the diversity of flow assurance issues that is likely to be managed during the development of the Brazilian Pre-salt areas, one final challenge must be highlighted: chemical product compatibility. A feasible tactic to combat all the flow assurance problems is subsea injection of chemical addictives. Dedicated umbilical lines and topside facilities for each chemical can be very expensive, or technically unfeasible, depending on the well completion and pipeline layout. Besides, there are uncertainties regarding the prediction of the flow assurance problems, which can lead to an unexpected requirement for a specific chemical. Combo products, which combine one or more chemical functionalities, have been sought as a reasonable solution to reduce the number of injection lines or manage with an underestimated injection system. Chemical compatibility is not an issue restricted to combo injection, but it is essential for any sort of simultaneous injection. The effectiveness of a particular chemical addictive can be affected by the presence of an incompatible chemical injected simultaneously through a separated umbilical. Compatibility evaluation has been performed as an approval test to certificate the chemical addictives to be used in the Brazilian Pre-salt areas.

Materials Selection and Corrosion Control Challenges

Materials selection for equipment and piping in the production of oil and gas requires the knowledge of the chemical and physical characteristics of the corrosive environment and of the operational conditions under which these materials will be exposed, in order to be sure the installations will present a good performance during the expected operational life of the installation. It is also necessary to take into account the cost and the market availability of the materials, in such a way that it is possible to select a material that has good performance, to the least cost, and with enough supply in order to avoid impact to the project schedule. Following below we will discuss how the typical conditions found in Pre-salt areas will impact the Materials Selections and Corrosion Control in the production installations.

Definition of the corrosion environment

In the Pre-salt areas it was observed the presence of contaminants in the produced fluid, especially CO_2. The occurrence of CO_2, in the presence of water, produces carbonic acid (H_2CO_3) which reduces the pH of the environment and causes uniform and localized corrosion in carbon steel. The reduction of the water pH also makes the presence of the H_2S more critical to the material. H_2S not only causes the occurrence of localized corrosion but also can cause the material failures due to sulphide stress corrosion (SSC). Another failure mechanism that is possible in these conditions is the chloride stress corrosion (CSC), caused by the chlorides present in the formation water.

Material Metallurgy Adequacy

In order to prevent the corrosion under this environment, the materials selection process may consider not only the use of corrosion resistant alloys, but also the use of protective coatings and/or chemical products for corrosion inhibition.

For equipment and piping that are subject to high pressure, such as wells and subsea lines, the high CO_2 partial pressure indicates the need to use special metallurgy in the parts exposed to the produced fluid, since the corrosion rate of carbon steel can be very high in these cases.

Table I shows the most common corrosion resistant alloys (CRAs) used in wells and subsea lines, and their properties in terms of strength and corrosion resistance, which is expressed in terms or PREN (Pit Resistance Equivalent Number). For these applications, a high strength is a most, in order to reduce the piping weight, making easier the operations for well drilling and subsea line installation. So, superaustenitic and duplex stainless steels are the most used options for wells and subsea lines. For topsides piping, regular austenitic steels and duplex are the most used options. Due to their expensive cost, nickel alloys (Inconel, Incolloy) are typically used in cladded (bi-metallic) pipes, where a thin (3mm) inner layer of the alloy is metallurgically bonded to regular carbon steel (see fig. 5). Claded pipes produced through the process of co-lamination (hot rolling) have been used in subsea pipelines, but their world supply is considered very limited. Clad by process of weld overlay has been more extensively used for protection of subsea equipment (e.g., WCT, valves, etc.) and topsides vessels.

Grade	Type	Chemical Composition				Fy (MPA)	PREN
		Cr	Ni	Mo	Cu		
13Cr	SuperMartensitic	13	***	***	***	550	13
S13Cr	SuperMartensitic	13	5	2	***	550	20
316	Austenitic SS	17	12	2,2	***	205	24
317	Austenitic SS	18	15	4,5	***	205	29
32205	Duplex SS	22	5,6	2,8	***	450	34
32750	Super-Duplex SS	25	7	3,5	***	550	41
904	Superaustenitic	20	25	4,2	1,5	220	36
31266	Superaustenitic	25	22	5,8	1,5	220	55
825	Nickel Alloy	22	42	3	2,5	440	32
625	Nickel Alloy	21	70	9	***	517	51
C276	Nickel Alloy	16	68	16	***	355	68

Table 1 – Corrosion Resistant Alloy properties

Figure 5 – Clad Pipe (3mm Inconel 625 + X65 carbon steel)

The first material option of less cost and better availability is the steel 13Cr. The critical parameters to be taken into account for this material are the pH and chlorides content. Previous studies and technical literature about the 13Cr limits the use of this material for chloride content of up to 50.000 ppm, what prevents the use in typical Pre-salt areas.

The next option would be the steel 13Cr-5Ni-2Mo. In tests carried out in Petrobras in an environment with pCO_2 of 80 psia and pH_2S of 1.5 psia in aqueous environment containing 115,000 ppm of chlorides showed that the pH should be above 4, for application of this material without the risk of corrosion failure.

The values of the pH will vary depending on the amount of CO_2 and the proportion between the injection water and the formation water in the produced water, what defines the pH of the environment. Considering this, the use of 13Cr-5Ni-2Mo may not be possible in some situations and so, more resistant material such as SuperDuplex (25Cr 7Ni 3Mo) shall be used.

Materials Selection:

- **Wells:**
  In the components that will be in contact with the produced fluid (tubing and casing below the packer) SuperDuplex (25-7-3) is the material usually considered for high corrosive environments. Extensive research is currently under way to assess the effect of the carbonates present in the reservoir on the produced fluid pH. If these tests confirm the expected increase in the pH, the 13Cr-5Ni-2Mo could be selected for the wells.
  In the parts that will not be in contact with the fluid (casing above the packer) carbon steel may be used.
  The Wet Christmas Tree (X-tree, tubing hanger and BAP) are usually fully cladded with 625 alloy.
- **Subsea lines:**
  Flexible lines are an option, provided the qualification process confirms the expected life of those lines due to the fatigue-corrosion phenomenon in the riser armor. Injection of H_2S scavenger at the production wells is foreseen as a contingency to prevent corrosion of the armors by H_2S. Considering CO_2 corrosion, the gas permeation through the risers' polymeric layer and the armor corrosion are an issue.
  Rigid lines are another option, but Inconel (625) clad will be certainly required at the critical fatigue sections of the risers.
  For the flowlines, SuperDuplex piping is considered a suitable option, provided that some measures are taken to prevent HISC (Hydrogen Induced Stress Cracking) due to interaction with the Cathodic Protection. Another option would be the use of lined pipes.
- **Topsides:**
  For the multiphase flow pipes that arrive to the platform, the low pressure of the fluid, results in a relatively mild CO_2 partial pressure, what makes possible the use of carbon steel. In more critical situations, the use of Duplex 22Cr (or better) would be an interesting option.
  For the produced oil lines after the fluid separation, the CO_2 concentration decreases making the use of carbon steel an obvious solution.
  On the other hand, for the wet gas lines after separator, where the CO_2 is concentrated, Duplex 22Cr or better is required. For dry gas lines and/or after CO_2 removal, carbon steel may be used again, without problem.
  For pressure vessels, cladding with 625 weld overlay or coating with epoxy cured with polyamine would be required

Production units

Mooring System:

The Pre-salt areas are located in waters ranging from 2,000 to 2,500m. Petrobras has already some units moored in similar depths, in Campos Basin, using light weight, synthetic (polyester) ropes. The use of free-fall (“torpedo”) piles has also made the installation of mooring lines at these depths a relatively common task.

The complication factor at the Santos Basin Pre-salt areas was that at this location, the waves are significantly larger than in typical Campos Basin fields. As you move southwards, from Campos Basin to Santos Basin, the waves get bigger and this effect is increased when you go farther from the coast (Pre-salt areas are at least 300 km far from the coast). The significant height of waves there is around 40% bigger than in Campos Basin, what resulted in the need to increase the number of mooring lines in spread mooring FPSOs, from 20 (typical figure for Campos Basin FPSOs) to 24.

Dry Completion Options:

Although the use of wet completion (floaters) is the basic option that Petrobras has used for production of deep water fields, the use of wet completion is always evaluated, and a DCU (Dry Completion Unit) is planned to be used at least in one of Campos Basin Offshore Fields. Since the beginning of the viability studies for the Pre-salt areas, the use of dry completion has been considered an interesting option.

So, one of our objectives was to overcome the bottlenecks to use DCUs in the Santos Basin Pre-salt scenario, what includes 3 main issues:

- **Spar Floatover:**
  The idea is to install the Spar topsides by floating them over the Spar hull, instead of mobilizing a huge derrick-barge to lift the topsides. Studies contracted by Petrobras showed that a window of 10hrs during south hemisphere summer with Hs (significant wave height) < 2m, what is required to safely perform the floatover operation, is possible. Detailed studies for Spar design are undergoing aiming the approval in principle of the concept.
- **TLP tendons:**
  At this water depth, the tendons pipes may become so thick that they are no longer buoyancy neutral, what would impact the load in the hull and could possibly make no longer attractive the use of TLPs. Studies contracted by Petrobras showed that a TLP at this WD is still technically feasible. Detailed studies for TLP design are undergoing, aiming the approval in principle of the concept.
- **Extended Reach Wells:**
  Probably the most critical issue is the drilling of high deviation wells through the salt formations. In order to confirm this possibility, many studies are undergoing, as well as the drilling of a pioneer high deviation well at a Pre-salt formation in Northeast Brazil. Drilling of a ERW in Santos Basin Pre-salt is also foreseen in the next years.

Gas Processing and Treatment:

The existence of contaminants in the oil demanded the use of facilities that are not typically found in our offshore units:

- **CO_2 removal:**
  Several options are available in the market for CO_2 removal, and the technology choice will depend mainly on the CO2 content on the input gas stream and the required CO_2 reduction, on the output stream. The design premises for gas exporting usually require the reduction of the CO_2 in the gas to 3 to 5%. It can be easily noticed that solid bed and scavenging that are used for low CO_2 contents (less than 3%) would not be an option if the produced fluid presents a large content of CO_2. Even the use of primary amines, that is the technology normally used for CO_2 removal in offshore plants, would be in the limit of the technology, for CO_2 content above 20%, requiring a lot of space for the modules, since the size of the plant is directly proportional to the amount of CO_2 required to be captured.
  So, the use of membranes which are more efficient for large contents of CO_2 gives an additional benefit of bring a more compact plant compared to the amines as it can be seen in Fig. 6 that shows the size comparison of two units of the same capacity, using membrane and amine technology (Dortmundt and Doshi, 1999).

Figure 6 – Size Comparison: Membrane Unit x Amine Unit

- **H_2S removal:**
  Where H_2S presence in the produced fluid was detected, Petrobras decided that facilities for H_2S removal at platform topsides would be required, although facilities for H_2S scavenger are still foreseen.
  If amine technology would be used for CO_2 removal, they would also be fitted for H_2S removal, but since this was not the case, the most logical option for this amount of H_2S (up to 200 ppm) was the use of fixed bed, what was the selected alternative.
- **Water removal:**
  As the exported gas would still present some CO_2 content (from 3 to 5%) is was of foremost importance to guarantee the gas dehydration. So, instead of having only TEG (Tri-ethylene-glycol) for reducing the water content, a set of molecular sieves is also foreseen what will reduce the water content in the gas to a very low concentration. The use of the sieves will imply in the need to install a Dew Point Control facility (Joule-Thompson) for removal of C6+ components from the gas, in order to prevent damage to the sieves.
- **Required Area x Production Capacities**:
  All the additional facilities for gas treatment that are foreseen, such as Fixed Beds, Dew Point Control Unit, Membranes Unit, as well as the facilities for re-injection of gas and CO_2 (high pressure compressors and CO_2 pumps) will impact the required area on the productions units. Since the size of the FPSOs was standardized (VLCC size) in order to facilitate conversion and construction of newbuilts in dry-docks, the capacity of the plant had to kept around 100,000~120,000 bpd.
  So, a big challenge that is faced now is to develop compact technologies for gas treatment, in order to allow the increase of the plant capacity in future production units.

Strategy to face technological challenges

To face technological challenges related to the production development of the Pre-salt reservoirs, PETROBRAS created a technological program – PROSAL - focused on anticipating solutions to the Pre-salt “points of attention” related to well technology, reservoir technology, scale (mineral salt precipitates) and flow assurance. The program has been organized by the end of 2007, and several R&D projects have been started since early 2008, in close cooperation with universities in Brazil and abroad, as well as service companies and other technology suppliers. R&D themes in well technology include drilling fluids, well stimulation, cement slurry to salt formations, geomechanical model in salt, geomechanical model in the carbonate rocks, liner drilling, geostearing in salt, well enlargement, drilling performance and multi-lateral well joints. R&D themes in reservoir technology include stratigraphy, structural geology, petrophysics, reservoir modeling, reservoir simulation and EOR. R&D on scale is focused in preventing and removing precipitates, with special attention on the compatibility between products. R&D themes in flow assurance include wax and hydrates.

Besides PROSAL, a corporate program name PACAP is dedicated to the "Well Construction Learning Curve Acceleration".

The history of success built by Petrobras in deep water Brazilian coast was largely supported by the PROCAP technological program, existing since 1986. The PROCAP program is now also focused on Pre-salt objectives related to riser configuration, selection of materials of flexible flow lines and preliminary projects of dry completion production units.

The PROGAS, another technological program dedicated to gas issues, is encharged of floating gas processing and exporting technologies in the Pre-salt scenario.

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