Marlim Complex Development: A Reservoir Engineering Overview

Abstract
Since the discovery of the Garoupa Field in the Campos Basin, Rio de Janeiro, Brazil, in 1973, Petrobras has been moving to deeper waters. Subsea engineering and well technologies have been developed and applied to overcome the environmental restrictions. Today more than 50% of Brazil’s oil production comes from fields located offshore in water depths over 1,000 m. In this scenario, the Marlim Complex – which comprises the Marlim, Marlim Sul and Marlim Leste fields – plays an important role.

Discussed in 1985, the Marlim Field started production in 1991, with a pilot system comprising 7 wells connected to a semi-submersible unit moored in a water depth of 600 m. Currently, the field production is about 85,000 m³/d (535,000 bpd), with 60 producers and 32 water injectors connected to deep production units. As with other Campos Basin turbidites, the Oligocene/Miocene reservoir of Marlim Field presents 3 outstanding characteristics: predictability, from seismic data and geological modeling, excellent petrophysical properties and good hydraulic connectivity. The extensive use of 3D seismics as a reservoir characterization tool allows the reduction of risks and the optimization of well locations. Additionally, 3D visualization techniques provide a new environment for teamwork, where seismic data is interpreted and input into detailed reservoir simulation models.

Among the deep water well technologies employed to develop the Marlim Complex it is worth mention: slender wells, high rate well design, horizontal and high angle wells in unconsolidated sands, efficient low cost sand control mechanisms, selective frac-pack with isolation between zones, pressure downhole gauges (PDG’s), new techniques for the connection of flowlines and X-mas trees, subsea multiphase pumping and special techniques to remove paraffin in the flowlines. However, new developments are required, such as extended reach wells, selective completion in gravel-packed wells, isolation inside horizontal gravel-packed wells with External Casing Packers (ECP’s), smart completion and improved recovery techniques for viscous oil.

Much has been learned during the planning and development of the Marlim Field and this knowledge is currently being applied in the development of Marlim Sul and Marlim Leste fields. Some important points must always be observed: a) the development plans must be defined by using optimization techniques considering the geological risks; b) the number of wells of the initial development plan must be defined through a detailed optimization study, considering economic indicators, oil recovery and risks; c) the wells must be designed to allow high production rates, with “rest of life” completions, as simple as possible; d) the sand control mechanisms must be simple, efficient and low cost; e) the seismic resolution or the production data analysis must be of sufficient quality to guarantee that there will be good hydraulic connectivity between the producers and the corresponding injectors; f) the pipelines and risers must be designed to avoid bottle-necks or conditions for deposition of wax or hydrates and g) the reservoir management and particularly the water injection system management must be made with an integrated teamwork approach.

In this paper we present some aspects of the reservoir engineering and of the development plan of the Marlim Field and briefly discuss how this experience is being used in the development of the neighboring Marlim Sul and Marlim Leste fields.

Introduction
The Marlim Complex comprises 3 giant deepwater oil fields – Marlim, Marlim Sul and Marlim Leste – located in the Campos Basin, 110 km offshore Rio de Janeiro, Brazil (Fig. 1). Besides the geographic location, these fields have other similarities: the main reservoirs are turbidites of Oligocene / Miocene age; 3D seismic data allows accurate prediction of the reservoir occurrence; rock characteristics are excellent; relative permeabilities are favorable to water injection and well productivities are very high.
The Marlim Field was discovered in 1985 by an exploratory well drilled in a water depth of 850 m, which found 70 m of the Oligocene / Miocene reservoir saturated with 20° API oil. Four additional appraisal wells delimited the accumulation, and the STOIIP is estimated at 1,020 million STD m³ (6,416 million STB). The field area is 165 km² and the water depth range is 600 - 1100 m. The oil API changes from 18° and 21° in the main field area, the oil viscosity in the reservoir is between 4 and 8 cp and the saturation pressure is 22 kgf/cm² below the original pressure of 287 kgf/cm². Rock characteristics are excellent.

To investigate well performance, reservoir connectivity, oil flow in low temperature pipelines, and also to test well completion and subsea technology, a production pilot was implemented in 1991. Seven subsea wells located in the northern field area were connected to a semi-submersible unit, Petrobrás-20 (P-20), moored outside the field area in order to reduce interference with development. All of the seven wells were perforated in the uppermost sand of the reservoir. The production pilot supplied important information which guided subsequent phases of the field development: a) RFT’s in new wells showed that all sands depleted at almost the same rate, showing that the reservoir has good vertical communication; b) subsequent wells drilled in the southern part of the field also depleted, proving reservoir continuity; c) material balance could be used to calibrate the reservoir volume calculated from geological mapping; d) for the longer flowlines, paraffin deposition reduced well potential, requiring remedial actions. In 1994 the first production unit of the definitive system, a semi-submersible unit named P-18 started operation, moored in a water depth of 910 m. This unit was designed considering oil processing capacity of 16,000 m³/d (100,000 bpd) and water injection capacity of 24,000 m³/d (150,000 bpd). Five additional units were installed in the field, and the present situation is shown in Table 1. Currently, Marlim Field production is around 85,000 m³/d (540,000 bpd) and the water injection factor to date is 7.2%. The water production is 3,300 m³/d (21,100 bpd) and the recovery factor to date is 19.5%

To date 19 reservoir blocks have been identified and mapped in Marlim Sul, but hydraulic connectivity between them is not completely understood. To investigate the reservoir performance 3 production pilots were implemented in the field: (1) In 1994 Well MRL-4, drilled in 1,027 m of water depth, started production to the platform P-20 in Marlim Field, flowing through 20 km of subsea pipeline. Currently it produces to P-26 through a 7 km flowline with a rate of about 1,800 m³/d. The material balance indicated that this well produced from a 170 million m³ STOIIP reservoir. In 1999 an injector in this block was connected to P-26, for pressure maintenance; (2) In 1997 the subsea completion world-record well MLS-3B, drilled in a water depth of 1709 m, was connected to a Floating Production Storage and Offloading (FPSO) through 3 km of subsea flowline. This well produced 16.5 API oil during almost one year, having reached a production peak of 1,500 m³/d. New subsea technology developed by the Petrobras Technological Program on Ultra-Deep Water Exploitation Systems (PROCAP) were successfully tested in this well. Besides, information regarding low temperature oil flow in pipes and gas-lift performance were obtained and allowed the calibration of the multiphase flow correlations. (3) Finally, in 1999 Well MLS-2, drilled in a water depth of 1,230 m was connected to the aforementioned FPSO, now repositioned to a shallower water depth. This well produces 2,500 m³/d of 22° API oil through a 3.5 km flowline. Again, production has allowed for material balance and the calculation of the oil volume connected to the well. The information obtained in these pilot production systems guided the development plan of the Marlim Sul field. The first production unit, the semi-submersible P-40, is schedule to start production in July, 2001, and 17 of its 28 development wells have already been drilled. New seismic data, acquired in the beginning of the year 2000, is helping to define the reservoir structure and internal stratigraphy and consolidate the development plan for the whole field.

The Marlim Leste Field was discovered in 1987 by an exploratory well drilled in a water depth of 1230 m. The well found 70 m of the Oligocene / Miocene reservoir saturated with 19.5° API oil. Four appraisal wells delimited the field, and the STOIIP is currently estimated at 230 million m³. In April, 2000, the discovery well was completed and connected to the platform P-26 in Marlim Field through a 11 km subsea pipeline. The well has been producing since then, with an average rate of 900 m³/d. Preliminary material balance data seem to confirm the mapped oil volume connected to the well. Presently, application of new technology is being studied in one of Petrobras PROCAP’s projects, in order to maximize the field value. Some of the alternatives considered are: electrical submersible pumps, subsea multiphase pump, subsea separation, simplified subsea manifolds, raw water injection and produced water reinjection above the parting pressure.

**Geology**

The Oligocene/Miocene turbidite reservoirs from the Marlim Complex form part of the Middle Eocene to Recent marine
regressive megasequence from the eastern Brazilian margin, which is composed of a group of synchronous depositional systems (strand-plain, fluvial-deltaic, fan delta, siliciclastic shelf, carbonate platform, slope, and deep-basin systems), typically displaying a progradational pattern (Fig. 2). The reservoir facies comprise mostly (1) amalgamated graded beds of unstratified, medium- (or fine-) to very fine-grained sandstones, and (2) Tab, Tabc, and Tbc Bouma beds of fine-to very fine-grained sandstones. All of the sandstone facies are poorly-consolidated, poorly-sorted, and have average low silt (<10%), and clay (<2%) contents). These sand-rich facies are interbedded with bioturbated mudstones and marls, which contain benthic foraminifera characteristic of mid to lower bathyal settings.

The majority of the sand-rich reservoirs from the Marlim Complex are part of 5-60 m-thick, 2-8 km-wide, and 5-12 km-long turbidite lobes, which accumulated in intra-slope, wide depressions developed in response of the eastward tilting of the basin, and the resulting downslope gliding of underlying, Aptian evaporites (Fig. 2). The amalgamation of several lobes can comprise up to 125 m-thick successions, with net-to-gross ratio typically ranging 80-100%. The reservoirs typically display a blocky pattern in gamma ray logs because of their uniform and low clay matrix; however, they commonly present trends of increasing-upward porosities in density logs, which are related to sand-rich successions that become finer-grained and better-sorted upward (Fig. 3). Reservoir porosities and permeabilities are relatively homogeneous (Fig. 4), typically averaging 27-30%, and 1,000-2,000 md, respectively.

Some of the Marlim Complex reservoirs can have a complex and discontinuous geometry as a result of the partial erosion by younger, low- to high-sinuosity, mud-filled channels. In the Marlim Sul field these channels are mostly 5-15 m-deep, and 200-600 m-wide, whereas in the Marlim and Marlim Leste fields the reservoirs are partially eroded by a single, 1-4 km-wide, up to 70 m-deep channel (Figs. 5 and 6). Major types of internal reservoir heterogeneities include (1) thin (< 3 m-thick) mud-rich horizons, and (2) horizons enriched in ellipsoidal (up to 1.0 m-thick, up to 2.5 m-long) calcite concretions. Fine-grained laminated sandstones and calcite concretions. However, RFT data from the Marlim Field wells (e.g. Fig. 3) show that these internal heterogeneities do not act, globally, as widespread barriers for pressure transmission.

The Oligocene/Miocene turbidite system from the Marlim Complex was subdivided into 9 zones in the Marlim Field, 7 zones in the Marlim Sul Field, and 4 zones in the Marlim Leste Field, mostly on the basis of stratigraphic discontinuities recognized in the well logs and in the high-quality seismic data (Figs. 2, 5, and 6). This high-resolution stratigraphic framework guides the drilling of the wells, particularly the positioning of horizontal or highly-deviated wells.

An integrated group of software for the development of well log interpretation, seismic interpretation, geological cross sections, 3D geological modeling, geostatistics, upscaling and finally reservoir simulation favored the integration of the team responsible for the Marlim Complex management. Besides the reservoir characterization activities, all of the alternatives related to the development plan are discussed between geophysicists, geologists and reservoir engineers. The decisions are taken only after a thorough analysis of the reservoir simulation and economical data.

Well Design and Drilling Issues
Since the drilling of the wildcat well 1-RJS-219A in 1985, many developments related to drilling technique were made in the Marlim Field. Improvements in well design, drill bits, drilling fluids and the use of new technologies helped to increase safety, cut costs and raise oil production.

In the earlier stage of the drilling in Marlim, when few data were available, one of the main concerns was related to the shallow and unconsolidated sediments. Initial designs used the common practice of jetting 48 or 46” pipes. In 1992 the designers substituted the 46” pipes for a 42” housing and conductor pipe of 13 m length resulting in reduction of time and cost. In 1993 it was decided to jet a 30” casing having a floating shoe at the end. This procedure not only proved to be better and more acceptable solution, but also reduced remarkably the time of the first phase.

Well designs in the Marlim Field also considered the type of the well: producer or injector. Expected flow rates determined the use of 9 5/8” production casing. On the other hand, 7” liners or 9 5/8” casings were considered acceptable for the last phase of injection wells. Most wells were drilled with four to five casing strings and took from 20 to 35 days.

By the end of 1997 and the beginning of 1998, the slender well technology (Fig. 7) was introduced, allowing the drilling of the first well in deepwater that carried only three casing strings: 30” / 20” / 9 5/8”. This well has proved that it is possible to reach the reservoir with the 20” casing with long extensions (2100m). After this first well a new world of opportunities was opened for well designers. The goal was to eliminate the 20” casing and to drill wells with the following casing program: 30” / 13 3/8” / 9 5/8”. There are some factors that contributed for the development of the three phase wells, such as geological peculiarities of the Campos Basin, knowledge of the area, evolution of drilling fluids, evolution of well heads. Slender wells reduced the total drilling time per well in three days.

A number of different problems such as bit balling-up, obstruction of the annular, dragging, swelling and well instability were typical of Marlim field. Although each one of these problems had different causes, most of time they were minimized by changing the type or the properties of the drilling fluid.

Completion Issues
Connection of flowlines and X-mas Tree. Due to the water depth in the Marlim Complex, the wellheads are far from the reach of divers. To deal with this situation, Petrobras developed the Lay Away Technique (Fig. 8) for running the X-mas tree or production base connected to the flow lines, avoiding pull in operations performed by divers. The use of
this technique was a very important step for the development of Marlim. Although this technique has allowed the development of the field, it has some limitations, such as the fact that the connection must be made directly to a floating production unit, instead of to a subsea manifold. This limitation led to the development of the Vertical Connection Method. However, this method also presented inconveniences, such as the cost of the dummy completion base, onboard handling of the dummy completion base and retrieval from sea bottom and the necessity of a completion unit and the lay vessel, although not simultaneously. The Direct Vertical Connection Method (Fig. 9) does not require a completion unit, and both the first and second connections can be performed with a lay vessel by lowering the flowline hub and landing it directly over the production adapter base or manifold and the dummy completion base is not necessary. At first it was required to install the flowline hub before the tree. Currently, after some design modifications, the tree can be installed either before or after the flowline connection.

Sand contention mechanisms. The reservoirs in the Marlim Complex are poorly consolidated and require the installation of sand contention mechanisms. Gravel packing (GP) was perhaps one of the most difficult and complex completion operations that was done on a routine basis in all the wells completed in Marlim Field. Different aspects must be considered, such as: the operations are made from floating rigs under harsh environment conditions (high waves), the high deviation angles in front of the pay zones and the necessity to a completion unit and the lay vessel, although not simultaneously. The Direct Vertical Connection Method (Fig. 9) does not require a completion unit, and both the first and second connections can be performed with a lay vessel by lowering the flowline hub and landing it directly over the production adapter base or manifold and the dummy completion base is not necessary. At first it was required to install the flowline hub before the tree. Currently, after some design modifications, the tree can be installed either before or after the flowline connection.

At first, the standard GP hardware were adapted in order to operate from floating rigs under harsh environmental conditions like high heave. Also the GP screens have been redesigned mainly to increase the screen area to blank area ratio in order to promote a better annular packing efficiency.

Despite the technology advances in gravel quality, wellbore impurities, fluid filtration and perforations, the high quality gravel packed wells were not producing as efficiently as theoretically possible. Therefore, based on research it was assumed that using a HEC fluid, sheared and filtered as the carrier fluid, did not pack perforations efficiently and the Xanthan Gum was adopted as an alternative. The continuous research in gravel placement technique introduced the water packing with brine as the carrier fluid as an alternative to viscous slurry packing, resulting in better perforation and screen/casing annulus packing.

Trying to optimize the packing efficiency and also to minimize the pressure drop introduced by the gravel pack, the high rate water pack technique and also the integration of fracturing and gravel pack sand control (frac-pack technique) were introduced. As the Marlim reservoirs are clean, homogeneous, and have high permeability, both the high rate water pack and frac pack are presenting the same good performance.

One of the goals in sand control in the vertical or deviated wells was the selective frac pack and zone isolation with a distance of approximately 12 m between the top of the lower zone and the bottom of the upper zone. (Fig. 10).

In addition to all the difficulties to operate in deep water, the reservoirs in the Marlim Complex present some unfavorable characteristics such as the oil viscosity and fluid loss control associated to high permeability and sand production. Horizontal wells have been considered a feasible and cost-effective alternative to gravel packed vertical or deviated wells. However, with the introduction of horizontal wells the problems related to wellbore stability should be considered not only in the drilling phase but also in the well productive life. Nevertheless, it is generally accepted that the economical advantages of horizontal completions will entirely make up for those technical difficulties. A good completion job of a horizontal well in poorly consolidated sandstone is strongly dependent on the way the production interval was drilled. Since drilling and completion designs of high angle and horizontal wells in these formations became fundamental, Petrobras established a program to collect the necessary data to run computer software to foresee a reliable stability analysis of the reservoir rock behavior.

In order to increase the exposed pay zone and very high producing rates, the open hole completion is the approach taken to complete the horizontal wells in the Marlim Complex. Despite the lower flow rate per foot of formation and consequently smaller flowing pressure drop than in a conventional well, numerical simulations showed that sand control is required, even in the horizontal injection wells. Dealing with open hole completions, the right choice of the drilling fluid grows in importance.

The first injection horizontal well in Marlim Field was drilled in 1995 with a saturated salt system and completed with a sinterized porous medium screen without gravel pack. The same type of completion was adopted for the next two horizontal producers without good result. Gravel pack was not used in these first horizontal completions because, at that time, we had the perception that there was no technology available to place gravel over a long horizontal interval. Research and studies in physical models confirmed that performing a successful gravel pack in a horizontal well using brine was feasible. So, currently, all the producers and injectors wells in the Marlim Complex are being drilled with a polymer-based drilling fluid, with calcium carbonate and a careful selected particle size distribution as a bridging agent. The Alfa and Beta gravel pack techniques are being used with excellent results, contributing for the field production records (Fig. 11).

The most recent new technology introduced in sand control in Marlim Field is the expandable screen (Fig. 12). This screen was installed in a deviated (66°) injection well, completed open hole. The well was drilled using with a polymer-based drilling fluid, with calcium carbonate. The same hole displacement and cleaning procedures were once again employed here. It was fundamental to run a caliper log to determine the expansion cone size.
Downhole gauges. As the Marlim Complex has only subsea wells, Pressure Downhole Gauges (PDG) is the most cost-effective method to collect data from the reservoir. The PDG system was improved along time and became a reliable method for monitoring the reservoir. Several actions were important for the evolution and quality improvement of the installations performed on Marlim Field, such as the use of quartz gauges instead of strain gauges, design a very resistant to mechanical impact downhole cable and redesign the electrical wet connector (Xmas tree & tubing hanger).

New technologies. Current challenges such as low fracture gradient associated with the increasing water depth, selective completion, shale intercalation and the low temperatures found in the deep marine environments of the Marlim Sul and Marlim Leste fields make the introduction of new drilling, completion and fluid flow technologies necessary. The low temperatures are among the main causes of paraffin and hydrate deposition. A way of minimizing such problems is to keep oil production underground by drilling Extended Reach Wells. The first ERW in the Marlim Complex will be drilled in the Marlim Sul Field, in the first semester of the year 2001, with the wellhead located at 1200 m of water depth, 5 km from the well target. The intervention costs are also predicted to decrease with the use of Smart Completions. Data from individual layouts will be continuously monitored, and it will be possible to adjust flow parameters by remotely controlling the downhole choke valves. New technologies in gravel packing operations are planned, such as alternate path technology and shale isolation using ECP in horizontal or high angle sections.

Multiphase Flow and Artificial Lift Design
The production system and the subsea layout in the Marlim field were developed keeping simplicity in mind. Due to their high productivity and to facilitate reservoir management, most of the wells are connected individually to their respective production units. Subsea manifolds were employed only where there was restriction to the total number of risers, the case of FPSOs P-35 and P-37. The production lines are typically of 6” diameter, while risers are 4” or 6” diameter, depending on the expected production rate. Most of the wells are equipped with a 5 ½” tubing and a single gas lift orifice valve. Some special high rate wells were completed with 7” tubing. The gas lift method was chosen due to its high reliability background in the Campos Basin. Despite the low API of the Marlim crude, its GOR of about 80 m³/m³ and the fact that all the wells are equipped with wet X-mas trees reinforced the choice for the gas lift method. The lift gas is supplied to the wells through individual injection lines, typically 2 ½” diameter, designed to operate at the maximum compression pressure of 170 kgf/cm².

Flow assurance. For the wells located far from the production unit and for those with small production, the Marlim oil may precipitate paraffin crystals. To avoid production losses, a system was designed to remove eventual wax deposits by periodically – typically each 15 days – circulating foam pigs in the production line. Therefore, most of the X-mas trees in the field are equipped with a pig-crossover connecting the lift gas line with the production line. This component allows the passage of a foam pig without damaging it. Multisize pigs were never used successfully in the Campos Basin. Nevertheless some of the wells were equipped with a 6” production line and 4” annular line to allow its use in the future. In some cases a more drastic removal procedure may be required, such as the SGN method. The SGN is a Petrobras’ patent, the name standing, in Portuguese, for “Nitrogen Generation System.” A chemical reaction is produced to generate heat that melts the paraffin deposits and clean the line. In this process local temperatures may rise up to 120 ºC. Special care is taken when there is a possibility of hydrate formation. At every well closure, the production and annular lines near the X-mas tree are filled with ethanol to prevent hydrate blockage. Nevertheless, if, for any reason, hydrate is formed, the cleaning procedure combines depressurisation of the annular and production lines and the injection of ethanol.

Subsea multiphase pumping system. An interesting event will take place in the year 2001: a production well was chosen to host the world’s first prototype of a subsea multiphase pumping system in deep water. It will be installed at a water depth of 641 meters, about 1,950 meters from the well head and 2,150 meters distant from the P-20 platform. The multiphase pump has a flow capacity of 500 m³/h, a maximum pressure gain of about 60 kgf/cm² and a maximum in-situ gas void fraction of 95% at the pump inlet. The shaft power is 1,268 kW, driven by a Westinghouse electric canned motor, whose speed is controlled by a Variable Frequency Driver (VFD) located at the platform. The prototype is to be installed in the first semester of 2001 for a minimum test campaign of two years. The average oil flow rate of this well in the next years should increase from 1,300 m³/d to about 2,100 m³/d, due to the pump. Currently the entire system is under preliminary testing in a pool, at the Atalaia Multiphase Flow Test Site, located at Aracaju, northeastern Brazil.

Reservoir Simulation
All reservoirs in the Marlim Complex are modeled with a commercial 3D black-oil simulator. Special features in the simulator are necessary, since forecasted production and injection requirements can be greatly under or overstated if optimization techniques are not used. Among the features of fundamental importance are: a) maximization of oil production or discounted cumulative production from satellite and platform wells within a framework of various fixed capacity platforms; b) dynamic calculation of well production and injection potentials to allow maximized oil production; c) pressure maintenance at specific pressure levels in different areas of the field; d) individual management of multiple reservoirs with pressure maintenance by water injection over different platforms; e) optimization of gas-lift with a limited gas supply; f) scheduling drilling and completion within a realistic rig availability scenario; g) consideration of platform
operational factors for production and injection to reduce average rates without interfere with well potential calculations; h) multiphase flow calculations for multi-lateral wells or wells connected to subsea manifolds.

**Water Injection**

The reservoir continuity, the relative scarcity of gas, the favorable characteristics of the relative permeability curves and the deepwater location lead to sea water injection as the most feasible method for pressure maintenance and increasing recovery in all fields of the Marlim Complex. In the Marlim Field the injection scheme is alternate line drive in almost the entire reservoir. In Marlim Sul and Marlim Leste fields, since reservoirs are segmented in lobes or blocks, there is not properly an injection pattern: the injectors are positioned in order to guarantee adequate pressure support for all reservoir lobes or blocks.

In the Marlim Field the water injection is made in the oil zone, concentrated in the lower portions of the reservoir and production is concentrated in the upper parts, to delay water breakthrough. The unfavorable viscosity relationship between oil and water is partially compensated by the favorable relative permeability characteristics. Due to the high reservoir permeability the pressure gradient between injectors and producers is very low and the water segregates, flows at the bottom of the reservoir and cones up to the producers. (Fig. 13).

The importance of the water injection in the Marlim Field can be understood by analyzing figures 14-17. To build these plots the 10 year production history was simulated in the numerical model with and without the water injection. It can be observed that a good match was obtained considering the real water injection data. However, if water injection had not been made the reservoir pressure would have fallen steeply, the GOR would have risen without control and production would have been very low.

To assure that the desired injection volumes could be sustained in the Marlim Field, it was necessary to control the injectivity decline which occurred in some of the injection wells of the platform P-18. To reach that goal several activities were carried out, involving people from different areas of the company. These activities were: (1) Auditing the injection water treatment systems that were already operating, (2) Strictly controlling the injected water quality through an index named IQUAI. This index comprises parameters which control the reservoir plugging (solids in suspension, oil and wax content, number of particles with size above the cut-off), corrosion and scale potential (oxygen and CO₂ content, soluble sulphide and bacteria), (3) Performing various laboratory measurements to determine the causes of the injectivity decline, (4) Carrying out a workover in an injector of the P-18 platform, to measure the injectivity decline and determine its causes. A backflow in this well showed that organic material was blocking the perforations, as a consequence of P-18 having injected for some periods without filtration. The injectivity was restored by extending the perforation and acidifying the formation. In the other wells the injectivity loss was not so serious.

All this effort has already been fruitful, since the injectivity decline was controlled in the P-18 injectors. Additionally, as a result of the injected water quality control, no injectivity decline is being observed in the wells served by the more recently installed water treatment and injection systems in the Marlim Field.

**Reservoir Management**

The surveillance and management of deepwater reservoirs is quite different from this same activity for reservoirs located onshore or under shallow waters. The main difficulty is related to data gathering due to the high costs of subsea wells interventions.

To partially mitigate the lack of data, all new wells are being completed with pressure and temperature gauges at the X-mas Tree and at bottomhole. If the gauge is operational, a complete well test – with build up – can be made from the production unit. In the near future, reliable electronic (intelligent) completion systems should allow remote data acquiring and remote well recompletion.

The production of each well is deviated to the test separator about once a month, when the production parameters are calibrated and the produced fluids are sampled and analyzed. The same is done with the water injectors. Diagnostic plots of productivity, injectivity, GOR, WOR, WOR' are constantly updated. The integration of these data allow the diagnosis of the well performance and of the multiphase flow efficiency.

The technology of 4D seismics may also be of great help in mapping the injected water paths, supporting operations like infill-drilling. A recent feasibility study for the application of the 4D seismics in the Marlim Field presented promising results.

As previously mentioned, the water injection in the Marlim Complex is a main issue. Besides controlling the injected water quality, the effects of this control – which are reflected in the injection cost - are permanently monitored: injection rate, injectivity index, frequency of tubing or flowline substitution, corrosion rate, filterability and solids composition at the bottomhole (obtained in the workovers). In the producers these effects are monitored with similar parameters and affect the production cost.

The quality control of the reservoir management process in the Marlim Complex comprises a) monthly meetings of the multidisciplinary teams – one for each production unit – when the main events and opportunities of improvement are discussed and the targets for the next month are established; b) monthly evaluation of all the indicators related to production and injection performance: injected water quality, injectivity and productivity of each well, well flow performance, operational efficiency of the platform, cumulative balance of injection and production, etc.

All the reservoir data – production, injection, well test results, pressures, fluid analysis, core analysis, etc – are stored in the company’s production data bank and can be retrieved.
and analyzed with the help of some in-house reservoir management software. The geological data – seismic profiles, time-depth conversions, geologic maps, well logs and rock correlations – are stored in another data bank. The integration of all the data is made with a commercial browser, which allows fast data retrieving and manipulation.

The production forecast and economic evaluation of all the projects related to the fields are revised quarterly, considering updated rig and boat schedules. The updated schedules take into account reservoir engineering priorities and equipment availability.

Finally, it is worth mentioning that no decision involving well intervention in the Marlim Complex is taken without an accurate economic analysis, supported by reservoir simulation. To date, few well interventions have been made in the Marlim Field and the main cause of these operations were: gravel-pack restoration, damage removal in injectors and hydrate removal in the X-mas trees or in the flowlines. Due to the high costs, the option of restoring a well is always compared with the side-tracking option and with the drilling of a new well.

Defining the Development Plan for Deep Water Reservoirs – Lessons Learned With the Marlim Field Development

In this section we present the methodology used to define the development schemes of the fields in the Marlim Complex. Much of the methodology has been established considering our experience with the Marlim Field development and is currently being applied in the development of Marlim Sul and Marlim Leste fields.

Value of information. Develop or not? The conditions to develop a deepwater field change from company to company, depending on its profile. Usually, however, a minimum set of information – wells drilled and tested, 3D seisimics, reserves estimates – should be available before triggering a decision. In the Marlim Complex, when defining the development planning, it is usual to propose work with 3 probability scenarios: minimum, medium and maximum. These scenarios are defined considering the uncertainties in the main variables: STOIIIP, oil properties, rock characteristics, relative permeabilities, well productivity or injectivity, hydraulic connectivity between wells and pressure maintenance behavior. Optimized development schemes are proposed for each scenario. Depending on the dispersion of the net present values (NPV) of the 3 scenarios – which directly correlates with risk – the decision to develop or not is made. If the decision is not to develop, it is necessary to quantify the amount of money which could be spent to get information, i.e., the value of information (VOI). At this point, the following methodology is applied: a) “optimized” projects are proposed for each one of the 3 scenarios; b) the project for the “medium” scenario is quantified for the minimum and maximum scenarios, defining the “non-optimized” projects; c) the difference of the NPV’s of the optimized and non-optimized projects for each scenario averaged with the probability of occurrence of each scenario define the Value of Information (VOI). The new information could be obtained with a production pilot, appraisal wells, a new seismic acquisition, detailed reservoir engineering studies, etc.

Production unit processing capacity. An important step is to define the processing capacity of the production unit. Many variables affect this decision: the company’s opportunity cost, the technological limit for offshore processing units, etc. A simple rule of thumb used in the Marlim Complex is that the depletion velocity of the area – or the unit’s capacity – should be higher than 3% of the STOIIIP / year or approximately higher than 6% of the mobile STOIIIP / year (considering Sor = 0.5*Soi). A more detailed analysis considers economic and risk aspects. Preliminary calculations are made with the reservoir simulator coupled to an economical analysis spreadsheet, which gives indications for the optimal capacities of each scenario. The reservoir engineering study is made with these preliminary capacities. After the optimum development scheme for each scenario has been defined, the analysis to establish the units’ capacities is repeated.

Number of wells. In deepwater production projects the NPV is strongly affected by the number of wells, since this item usually responds for more than 50% of the CAPEX. It is then recommended that a detailed study be made to select the well distribution and the number of wells, considering not only the economic indicators but also oil recovery and reduction of risks. In the Marlim Complex this process begins by generating several possible drainage schemes, through a strong interaction between geophysicists, geologists and reservoir engineers. For each scheme the number of wells is varied and all the alternatives are tested with the reservoir simulator. The initial sensitivity analysis indicates the best drainage concept for the reservoir. More recently, the optimization considering the quality maps 14 is being used and the results are promising. Once the conceptual development scheme has been defined, other simulations are made, reviewing the number of wells and repositioning them. The following indicators 15 help rank the wells: a) Oil Recovery indicator (OR), obtained by dividing the oil recovery of the well by the average well recovery. In the Marlim Complex, under current conditions, wells with a simulated recovery of less than 2.0 million m³ are not selected to be drilled in the beginning of the project, and remain as future opportunities to increase the production and the recovery. b) Relative Cost (RC), the relation between the investment to connect the well to the production unit and its cumulative production, both discounted to present date using the company’s minimum interest rate. c) Risk Factor (RF), a number between 0 and 1, which includes the confidence regarding not only the expected thickness but also the connectivity of the well with the corresponding injectors. d) Selection Factor (SF), the combination of OR, RC and RF, composing oil recovery, economics and risk. The indicators for all the wells are plotted and the wells are ranked. Detailed reservoir simulations are performed, varying the number of wells according to the...
Risk analysis – Technical-Economic Feasibility Study. If the project is considered robust, i.e., is economic in the minimum case, even considering the uncertainties in oil price, CAPEX and OPEX, then it is time to start the investments. However, as uncertainties are present, the development plan can not be deterministic. A base case, usually the “medium” or P50 scenario, is considered in the technical-economical feasibility studies. However, although the definition of the project is made with the base case, some leeway is provided, whenever possible, in the processing unit main systems and well slots in the manifolds or at the platform.

As previously mentioned, the project for the “medium” scenario is also quantified for the minimum and maximum scenario. The expected NPV is calculated by averaging the NPV of each scenario with its probability of occurrence.

Pressure maintenance. Even if a strong natural drive mechanism exists, pressure maintenance through gas and water injection must be evaluated in deep water reservoirs. In particular cases it is worth evaluating polymer injection or water alternating gas (WAG) floods. In deepwater projects, due to the intensive investments, oil production should be high and remain constant in the first years, which requires an efficient pressure maintenance mechanism. In the main reservoirs of the Marlim Complex the reservoir mechanism is solution gas drive. Water injection has been selected as the pressure maintenance method, for its simplicity and also due to the relative permeabilities favorable to waterflood. Polymer flooding and WAG have been studied but were not implemented.

Potential problems associated to flow assurance and water injection. In the Marlim Complex all the main projects were preceded by pilot production systems, and consequently the uncertainties related to the flow assurance were reduced. Regarding water injection, some problems were observed – and corrected – in the Marlim Field. Additionally, a water injection pilot is operating for more than one year in the Marlim Sul Field, with excellent results. Based on this experience we are confident of the success of water injection in the future projects. The hydraulic connectivity between injectors and producers is a major point to be investigated. If seismic resolution is not sufficient to clarify this point and if it is not possible to implement a pilot production system, it is normal to start the project by drilling and connecting the producers, confirming the injectors’ locations only after analyzing the RFT’s data in the pilot wells which precede the correspondent horizontals.

Conclusions
Developing a deep water petroleum reservoir is a complex task, which requires full integration of all upstream disciplines. In this paper we presented the experience obtained with the development of the Marlim Field, which is currently being used to optimize the development of the neighboring Marlim Sul and Marlim Leste fields and other deepwater fields in Brazil. Some important lessons, or “golden rules,” were learned:

1. The decision to develop a deepwater field must consider and quantify the risks involved. The value of new information – seismics, appraisal wells or production pilot projects – must be estimated.
2. The development plan must be defined using optimization techniques, considering the geological risks.
3. The number of wells must be defined considering oil recovery, economic indicators and risks. In the Marlim Complex, under current conditions, wells with a simulated recovery of less than 2.0 million m³ are not selected to be drilled in the beginning of the project, and remain as future opportunities to increase the production and recovery.
4. The fluid process capacity of each production unit must be defined through an optimization analysis. In the Marlim Complex the reservoirs are depleted with a velocity higher than 6% of the mobile oil volume per year.
5. Integrated software and integrated teamwork are important factors for defining the development schemes of deep water reservoirs. All the decisions, including well interventions, must be supported by detailed feasibility studies, including risks. A 3D reservoir simulator, including accurate reservoir characterization and calibrated by the production and pressure data, is a key tool in this process.
6. To assure high production rates, pressure maintenance must be efficient. If water injection is planned, the hydraulic connectivity between injectors and producers must be well defined through seismic data, well log correlation or production and pressure data.
7. Well completions must be designed for the “rest of life” to avoid costly well interventions. The wells must be designed to allow high rates, which means, in the Marlim Complex, rates higher than 2,000 m³/d.
8. The subsea pipelines and risers must be designed to avoid bottle-necks, as well as the conditions for wax or hydrates deposit.
9. The reservoir management process must involve all the upstream segments, permanently analyzing the opportunities to optimize the development plan. Particularly, the water injection system must be managed with an integrated teamwork approach.
10. The technology to be applied must have been tested and accepted in similar environment. In the particular case of the Marlim Field the development was modular and the technologies were developed and tested during the project, otherwise the field development would not have been possible. New technologies were acquired in several areas, such as: well drilling, well completion, sand containment, multiphase flow in pipes and subsea engineering. The new technologies devised for the development of the Marlim Sul and Marlim Leste fields comprise: extended reach wells, selective completion in gravel-packed wells, isolation inside horizontal gravel-packed wells with ECP’s, smart completion and improved recovery techniques for viscous oil.
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References

### TABLE 1 – MAIN CHARACTERISTICS OF MARLIM FIELD PRODUCTION UNITS

<table>
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<tr>
<th>Unit</th>
<th>P-18</th>
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<th>P-20</th>
<th>P-33</th>
<th>P-26</th>
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<td>SS</td>
<td>FPSO</td>
<td>SS</td>
<td>FPSO</td>
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<td>990</td>
<td>850</td>
<td>900</td>
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<td>9,500</td>
<td>9,000</td>
<td>20,000</td>
<td>20,000</td>
<td>28,000</td>
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<tr>
<td>Water injection capacity (m$^3$/d)</td>
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<td>28,000</td>
<td>-</td>
<td>12,700</td>
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<td>25,000</td>
<td>40,000</td>
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<td>4</td>
<td>10</td>
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<tr>
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<td>-</td>
<td>3</td>
<td>6</td>
<td>6</td>
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SS: Semi-submersible; FPSO: Floating Production, Storage and Offloading

**Figure 1** – Location map for the oil fields from Campos Basin. Deep-water turbidite fields in darker colors.
Figure 2 – Typical seismic profile for the eastern Brazilian margin: (R) continental rift megasequence, (T) transitional evaporitic megasequence, (SC) shallow carbonate megasequence, (MT) marine transgressive megasequence, and (MR) marine regressive megasequence. The top of the Marlim Field reservoir is indicated by MRL. The accumulation is defined by reservoir pinchout to the west, and by a large fault to the east, which acted as a conduit for oil migration from the rift megasequence.

Figure 3 – RFT data and density/neutron logs from a Marlim Field well.

Figure 4 – Core porosity and permeability in the Marlim Complex.
Figure 5 – Seismic impedance map for the Marlim Field reservoir (after Abreu et al., 1998). Red and orange indicate thicker sandstone successions. The large extension (165 km²) and thickness (up to 125 m) of the reservoir resulted from the amalgamation of sand-rich lobes deposited by three very active feeding systems, which are indicated by black arrows. The easternmost boundary of the field is defined by a normal fault.

Figure 6 – Strike seismic (amplitude section) for the Marlim Field reservoir. Section has similar orientation to that of Figure 2. A mudstone-rich horizon is indicated by m, and two horizons with concentration of calcite concretions are indicated by c. The reservoir is truncated by an up to 70 m-deep, 3-4 km-wide channel.
Slender wellhead 16 ¾” for deepwater.
Figure 10 – Selective frac pack

Figure 11 – Horizontal gravel pack using alfa and beta system and premium screens

Figure 12 – Expandable Screens
Figure 13 – Cross section showing water saturation (lighter color) in the years 2000 and 2010, Marlim Field (P-18 area)

Figure 14 – Marlim Field. Production and injection

Figure 15 – Marlim Field. Pressure match

Figure 16 – Marlim Field. BSW match

Figure 17 – Marlim Field. GOR match