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HP/HT Well: Fluid Selection, Planning and Lessons Learned

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Abstract

As the world's energy demand increases and drilling technology improves, more and more wells are being drilled in hostile environments such as ultra-deepwater, geothermal zones, high pressure / high temperature (HP/HT) areas, etc. These types of wells present challenges not often encountered in normal drilling situations. Consequently, special considerations in the planning phase can help to mitigate some of the major problems experienced while drilling.

A well with a bottomhole static temperature greater than 325˚F (190°C) and with hydrostatic pressure greater than 17,500 psi (1,207 bar) is classified as a "critical or challenging well" by many operators and service companies. Critical or challenging wells have additional requirements not only in the drilling phase of the well but also in the extensive planning stage.

For an HP/HT well in the Santos basin offshore Brazil, several key aspects were considered to determine the best fluid for the project. Ultimately, a water-based mud was selected as the fluid of choice for this "critical well."

This paper reviews the drilling fluid selection process, the laboratory validation, and the drilling fluid used on this HP/HT well. It also summarizes the lessons learned from the HP/HT section of the well.

Introduction

Santos basin offshore Brazil, located 300 miles (483 km) south of Rio de Janeiro (**Figure 1**), is one of Brazil's largest sedimentary basins[1] where operators are drilling various types of wells. These include but are not limited to deepwater, pre-salt, horizontal, shelf and HP/HT wells. Each of these well types offers its own specific design criteria and challenges.

HP/HT wells offer challenges that require multi-discipline cooperation in order to provide the best solutions. Challenges range from the obvious health, safety and environmental (HS&E) aspects to the more HP/HT-specific aspects, such as calculating the bottomhole circulating temperature (BHCT) as a function of time. Each of these challenges should be addressed and reviewed in a basis of design (BOD), as a failure could be catastrophic.

Learning from these extraordinary projects is essential for expanding the knowledge base of HP/HT within the industry. With relatively few experts, each company relies on its ability to record critical events, analyze the events, and then injecting the knowledge gained into the organization as lessons for use by others. The "critical well" description, **Figure 2**, is one which extra attention to detail is required. The successful HP/HT project that is the subject of this article was in part due to the front-end loading and careful reviews conducted on a continual basis by the operator and service companies.

Critical or challenging wells require additional attention in the planning stage in order to mitigate possible problems from occurring that can cause significant cost over runs. According to Zamora[2], the calculation of a Quality Element Deployment (QED) category Q6 is a moderate-to-critical well requiring high-to-maximum planning. The participants of this project recognized early in the pre-planning process that the well described below would fall into the Q6 category (**Figure 3**). Consequently, additional planning resources were made available from both the operator and the service companies.

The exploratory HP/HT well was located in Santos Basin offshore Brazil at near 500 feet (152 m) water depth and was to be drilled to a total depth (TD) approaching 22,000 feet (6,706 m) with a bottomhole static temperature (BHST) of 390°F (199°C). A similar or like well previously drilled by the operator was used to correlate the casing points with pore pressure and expected BHST. The planned maximum density of the drilling fluid was 17.5 lb_m/gal (2.10 sg) or a hydrostatic pressure of 20,000 psi (1,380 bar). The combination of these facts placed this well in the challenging well list for the operator and in the critical well list for the drilling fluid service company.

The HP/HT section of the well was to be drilled in an 8½-in. hole section. The focus in this section was placed on ensuring no fluid gelation or extreme thickening during long exposure times occur while being out of the hole for either changing of a bit, BHA or during logging of the section at the end of the well.

Fluid Selection Process

The project was started with an internal review by the drilling fluids service company for the selection of a drilling fluid for use on this HP/HT well. The fluid options were an HP/HT water-based system (WBM) or an HP/HT mineral oil-based system (OBM) with the technical criteria as shown below:

- Discharge of all cuttings
- Temperature stable to excess of 380°F (193°C)

- Fluid stability at high densities, 17.0 lb_m/gal (2.03 sg)
- Fluid stability under acid gas contamination, carbon dioxide (CO_2) or hydrogen sulfide (H_2S)
- Fluid suitable for logging tool data acquisition
- Resistance to differential sticking, must be able to provide fluid loss control after extensive aging
- Performance and economical reasons for fluid selection

The fluid selection process was divided into three categories. First were the environmental aspects of the fluid, second was the fluid history and experience, and third was a laboratory evaluation and engineering computer modeling. The results for each of these categories were examined closely and presented at a Basis of Design (BOD) review.

Environmental Aspects

The environmental regulatory agency of Brazil, Instituto Brasileiro do Meio Ambiente e dos Recursos Naturais Renováveis[3] (IBAMA), has set guidelines to be followed for the testing and must approve of drilling fluids for use offshore Brazil. These guidelines differ for WBM and OBM or synthetic-based mud (SBM) but include acute and chronic toxicity tests, biodegradation tests, Log P_{ow} and HPA. See **Table 1.** The later three tests apply only to non-aqueous fluids.

In addition to the environmental testing for approval for use, IBAMA has set discharge limits for the drilling fluid and the drilled cuttings associated when drilled with WBM or OBM. For WBM, an approved fluid can be discharged to the sea with a pH of less than 9.0, recording the volume and rate of discharge, while an OBM may not be discharged. Drilled cuttings can be discharged for both WBM and OBM. Drilled cuttings from the drilling with WBM can be directly discharged while when OBM fluids are used the percent by weight of retained oil on cuttings (ROC) must be less than 6.9% for the cuttings to be discharged to the sea. According to the United States Environmental Protection Agency the average ROC for a baseline solids control package used in 1999 to 2000 was 10 to 11 % by weight[4].

Equally, both the HP/HT WBM and the HP/HT OBM fluids have been formulated and pass the required environmental testing of IBAMA for use offshore Brazil. To achieve the ROC of 6.9% by weight, additional equipment and personnel may be required on the rig while OBM or SBM are in use.

HP/HT Fluid History and Experience

The drilling fluid choice for the HP/HT project included both water-based and oil-based fluids. Both fluid types can be specially designed for and have a history of use in the difficult environment of HP/HT wells.

The first generation of water-based geothermal fluids in the Imperial Valley, California was established in 1976. This fluid evolved into the third-generation geothermal fluid in 1980[5] and has made modest improvements since that time. Geothermal wells in the Imperial Valley expose the drilling fluid to extreme conditions: temperatures in excess of 500°F (260°C), high levels of carbon dioxide, soluble calcium and high chlorides. Even with these extreme conditions the drilling fluid must not only remain a liquid, but must maintain proper viscosity and fluid loss control while drilling and during trips. A WBM system capable of achieving this would be an ideal candidate for use on HP/HT wells.

Oil-based fluids are also well suited for drilling HP/HT wells and have been used at temperatures above 500°F (260°C) and with mud densities above 18.0 lb_m/gal (2.16 sg)[6].

To determine the recent experience with HP/HT water-based fluids and HP- HT oil-based fluids, the wellsite-reporting database of the drilling fluids company was queried and filtered for wells with bottomhole temperatures and drilling fluid densities similar to the planned project.

The filtered database query results of both WBM and OBM were reviewed in order to examine the critical fluid properties that affected system pressure loss, fluid loss to the formation and stability of the fluid over time.

To assist in the analysis for comparing critical drilling fluid properties, data mining a database that contains all of the drilling fluid data from rigsite mud checks was conducted. Percentiles, a measurement describing the frequency that a value falls within a set of values[7], were determined for various critical drilling fluid parameters. For each critical property, a P_{25}, P_{50} and P_{75} were determined.

HP/HT products were used on various wells globally, which meet the density and temperature requirements of the proposed well. **Table 2** contains the analysis of the HP/HT WBM laboratory tests, and five HP/HT wells using the HP/HT WBM system using the P_{50} or median of reported values. **Table 3** contains the average properties of the fluid for the laboratory tests, and four HP/HT wells using HP/HT OBM products.

Laboratory Evaluation and Engineering Modeling

Laboratory tests were conducted to achieve a stable viscosity and stable filtration control over a prolonged period of aging at 380˚F (193°C). Specialty products were required to obtain the objectives for both WBM and OBM fluids.

One major criteria for the fluid was for the fluid not to exhibit extreme thickening or gelation during long exposure to the high bottomhole temperature that would be seen during tripping and logging operations. The two proposed fluids were subjected to extensive laboratory aging tests. Samples were prepared and dynamically aged for 16 hours at 380˚F (193°C) for initial results, then aged under static conditions for an additional 72 hours at 380˚F (193°C) for the aged results. Both fluids exhibited good rheological properties and fluid loss control over the time period of a total of 88 hours at 380˚F (193°C) as seen in the **Table 4**.

With the fluid composition and the determination of downhole viscosities from the laboratory evaluation, computer modeling was conducted using engineering programs for temperature modeling and HP/HT hydraulics. Due to the thermodynamic properties of water, the WBM results in a lower BHCT and slightly higher flowline temperature as compared to the OBM. Due to the highly compressive nature of oils, the OBM fluid exhibited higher modeled equivalent circulating density (ECD), equivalent static density (ESD) and standpipe pressure (SPP) as compared to the WBM system. Even if the surface density of the OBM were reduced to result in an ESD similar to the WBM, the differential between the ESD and ECD remains less with the WBM than the OBM. **Table 5** shows a comparison between the two fluids for the results of the critical modeling.

Planning

Considerations and findings of the fluid selection process, as described above, indicated that either an HP/HT WBM or an HP/HT OBM was suitable for the drilling of this "critical well". Therefore, the decision was made to use the HP/HT WBM for this project with a goal of capturing additional evidence of the capability of the fluid as the fluid could be used in other operations.

Due to the nature of this project the front-end loading was considerable. HS&E, the drilling fluids program, HP/HT modeling, personnel selection and conducting a BOD review were a few of the items closely examined and thoroughly documented.

Health Safety & Environment

Highlighted during the planning of the project were five aspects of HS&E that are prevalent in HP/HT drilling operations: elevated flowline temperature, trapped pressures, hazards while mixing caustic soda, hydrogen sulfide gas and gas at surface after trips.

As with HP/HT wells, fluid temperatures at surface, and in particular at the flowline, need to be discussed thoroughly with rigsite personnel. Fluids can easily reach temperatures that can scald or burn a person within a few seconds as seen in **Figure 4**[8]. Awareness of this fact is important as personnel working in the shaker house routinely collect samples of the drilling fluid to determine the fluid density and viscosity. Additionally, personnel are exposed to the drilling fluid when changing shaker screens and performing other maintenance on the solids control equipment.

Conditions for trapped pressure can be found in HP/HT wells. Higher SPP are present during drilling, BOP testing, cementing and other activities. One must take extreme caution when crossing lines and it is imperative that no one crosses an area that has been taped "off limits". Discussion with rig crews and contractors during "toolbox" talks or pre-job safety meetings concerning operations and areas to have increased vigilance is essential.

As with most water-based drilling fluids, chemicals with a pH greater than 7 are used to maintain the pH of the fluid above a minimum point. In HP/HT wells the chemicals used for pH control are mixed at a greater rate compared to conventional wells (**Figure 5**), thus exposure and possible harm to workers is increased. All personal protective equipment (PPE) must be used as directed by material safety data sheet (MSDS) information when handling chemicals at the wellsite.

Acid gas, hydrogen sulfide, H_2S, is commonly present in HP/HT wells[9]. This gas can be naturally occurring or be a by-product of chemical decomposition in the high-temperature environment. Not only must these gases be closely monitored, but it is necessary to have a plentiful stock of material that can be used to treat H_2S if it is encountered.

An issue that can easily be overlooked is the possibility of gas at surface. With the use of a non-aqueous fluid, gas can be in solution in the liquid phase of the drilling fluid at high temperature and pressure. This gas remains in solution until the pressure decreases to the point that the gas comes out of solution and expands rapidly. Although the solubility of gas in a WBM is less, the problem of gas reaching the surface can not be taken lightly. Pit drills should be conducted regularly and personnel should be fully aware of their responsibilities in well control situations.

Fluid Program

Two years previously, a like well was drilled in the area. That well encountered fluid gelation problems that were highlighted in the fluids program of the current well.

The plan for the HP/HT section of the well was to determine if the fluid from the 12¼-in. section, a high-performance WBM (HPWBM), was suitable for the beginning of the HP/HT section. This was to be done by conducting laboratory tests at elevated temperatures. All HP/HT specialty products were to be pre-mixed and used as needed to maintain filtrate and viscosity control.

The design of the HP/HT drilling fluid incorporated the minimal number of products and at low concentrations to achieve the required drilling fluids' properties and stability. A combination of three fluid loss control agents were used to maintain the API fluid loss and the HP/HT fluid loss: a polymer/lignite blend, a copolymer and a sulfonated polymer, all having temperature stability in excess of 300°F (149°C). API grade non-treated bentonite was used at minimal concentrations for building the first batch of new drilling fluid. To prevent the drilling fluid from thickening with time at a high bottomhole temperature, a derivatized synthetic interpolymer that is stable to above 400°F (204°C) was used. This synthetic interpolymer requires no sodium hydroxide for activation; thus it is effective at a wide range of pH.

Special requirements and sampling procedures for laboratory tests were defined early in the program. These critical requirements were set to capture information that may be used in campaigns in which HP/HT WBM may be used.

To assist in logistics on this offshore operation, a daily report was required that specifies the maximum fluid volume that could be built with the products on the rig. This was to be accomplished by determining the concentration of chemicals in the fluid and the stock of chemicals on the rig. This would highlight each chemical's safety stock required on the rig. In addition to the volume of fluid capable of being built, the report also specified the maximum achievable density using the current density of the drilling fluid and the amount of weighting material on the rig. See **Table 6.**

Weekly drilling fluid samples were to be collected and sent to the local laboratory for screening. The tests included complete mud checks, particle size distribution (PDS), HP/HT viscometer and static aging tests. Mud checks would be a quality test of the drilling fluid to be sure all equipment on the rig was adequately calibrated. PSDs would be used to monitor the buildup of colloidal solids in the drilling fluid, which can indicate the need for a transfusion of "clean" fluid. HP/HT viscometer tests demonstrate how the viscosity of the fluid is changing with temperature and pressure. These values are used in hydraulic modeling to understand and predict the pressure losses observed while drilling or circulating. The static aging tests were designed to be conducted for 16 and 40 hours at a temperature of 25°F (13°C) above the calculated bottomhole geothermal temperature. This information would be used to determine if the fluid was stable or if additional chemical treatments would be required.

HP/HT Modeling

Pressure loss modeling in the planning stage is used to determine the range of the operating pressure while drilling or circulating. The calculated SPP and equivalent circulating and static density (ECD and ESD) are highly dependent on the circulating temperature, the behavior of the rheology and density of the fluid under HP/HT conditions[10]. The circulating temperature profile can be modeled using sea floor temperature, geothermal gradients, wellbore and drillstring geometry, drilling fluid characteristics and expected drilling parameters. Once the BHCT profile is developed, the annular pressures are subsequently determined and then used to ensure that the operation can be done within the drilling pressure window.

During the planning stage, extensive temperature modeling was conducted to establish the BHCT that would be used in the pressure loss modeling. Pressure loss modeling included SPP and ECD analysis to indicate the flow rates that would be possible with the planned bottomhole assemblies, downhole tools and drillstring. This information was used to develop the hydraulic drilling window for the well, that is, to determine the operating window between downhole pressures of the fluid system and fracture pressures of the wellbore.

Personnel

One of the key aspects for the success of this project was to identify and secure personnel with experience in HP/HT projects. Networking within the organization was critical and produced a list of experienced personnel who were available for the field operations. Having experienced personnel on the project enabled knowledge gained on like wells to be brought into the operation quickly and effectively.

Basis of Design Review

A thorough basis of design (BOD) review was conducted once the fluid and rigsite personnel were selected and the drilling fluid program was developed. The review was used to identify any missing or unclear items in the plan.

Participants for the BOD review included subject matter experts in the field of drilling fluids, solids control equipment and processing and drilling operations. This broad mix of personnel was engaged in the examination of all of the aspects of the preparation, use and testing of the proposed drilling fluid.

The BOD review focused on the documentation and justification of the proposed plan. Each step of the drilling process was discussed in detail and agreement was reached on how the plan would be executed.

Outcome and Lessons Learned

The focus of the following discussion will be the drilling and flat time associated with the last two sections of the well, which were considered to be the HP/HT sections of the project. The 8½-in.section and the 6-in.section were drilled using the HP/HT protocol developed by the operator and the rig contractor. To facilitate the training and the understanding of the HP/HT procedures, a training company was employed and present on the rig at the beginning of the 8½-in.section.

The first HP/HT section of the well

The first HP/HT section of the well was drilled with an 8½-in. bit. The previous casing string, a 9⅝-in. long string, was set with a BHST approaching 300°F (149°C). The drilling fluid products of the previous section, including the circulating volume of a high-performance water-based system (HPWBM) with a mud weight of 11.2 lb_m/gal (1.34 sg), were transferred to the HP/HT section. The HPWBM was deemed to be in good condition after three days of remaining static within the wellbore during the change over from the 12¼-in. to the 8½-in.sections.

The leakoff test (LOT) resulted in a value that was insufficient for drilling the complete interval. The shoe was cemented and squeezed in an attempt to improve the LOT. The second leakoff test was still lower than anticipated, resulting in the need to set a drilling liner if the ECD of the drilling fluid approached the LOT.

The system was circulated while increasing the fluid density to the initial mud weight for drilling in HP/HT mode. During the circulation period, materials for the HP/HT WBM system were added and a 20% by volume dilution was made with pre-hydrated untreated bentonite. The dilution volume contained 20 lb_m/bbl (57 kg/m^3) of premium-grade, natural Wyoming bentonite meeting API specifications for untreated bentonite.

Once the mud weight was balanced at 15.0 lb_m/gal (1.80 sg), the HP/HT drilling mode was initiated. All mud treatment was controlled by mixing in the reserve pits and transferring to the active system as per HP/HT operating procedures developed for this well.

While drilling the section, the inclination of the well increased slightly and the decision was made to pull out of the hole to change the bottomhole assembly and make a correction run. The fluid was treated with a derivatized synthetic interpolymer to avoid any flocculation, as the BHCT was 235°F (113°C). This fluid system additive functions as a water-based deflocculant and rheological stabilizer with special application in high-temperature environments. The mud weight was raised up gradually to 15.5 lb_m/gal (1.88 sg).

A rotary steerable assembly was run into the well and the drilling fluid was circulated at a depth where the bottomhole temperature was near 250°F (121°C) in order to cool the MWD tools to acceptable values before running to the bottom of the well. At bottoms up from the TD depth, a lowered pH and an elevated API fluid loss were noted but these were expected after ± 65 hours out of the hole. The fluid system was treated with a chemical pre-mix: water, a powerful filtration control, rheological stability agent and a derivatized synthetic interpolymer. As a result, ECD was reduced by 0.4 lb_m/gal (0.05 sg).

All additions of treated slurries were made via transfer from reserve pits to the active system in order to closely monitor volumes at all times, as per HP/HT procedures.

While drilling ahead, HP/HT product consumption increased as bottomhole temperatures increased. Fresh water was added to the system along with filtration control agents. Treatment with water was effective in lowering rheological values for approximately 10 hours, and then they started to climb again. The pH was hard to maintain with magnesium oxide because of the temperature. Throughout the section the drilling fluids properties fluctuated moderately as demonstrated in **Figure 6.** Periodically, the well would be circulated while making treatments to reduce the ECD of the fluid.

Drilling continued, increasing the fluid density as needed until the liner point was reached and the remaining cuttings were circulated from the wellbore. At that point, five stands were pumped out of hole and tripped back to bottom and circulated bottoms-up before tripping out of the hole. Logging operations were conducted and then a 7-in. liner was run and cemented.

Lessons Learned #1

This section of the well qualified as one of our "critical wells" due to the bottomhole temperature and pressure. During the planning phase of the project it was identified that several technical hurdles needed to be overcome for an HP/HT fluid to be successful. These included stable viscosities at high temperatures for prolonged periods of time while logging and running casing, stable HP/HT filtrate values and no drilling fluid gelation.

This section of the well was drilled according to the plan. No non-productive time related to the HP/HT drilling fluid was recorded during this phase of the program as demonstrated by the IADC chart, **Figure 7**. As seen in the Bottoms-Up information, **Table 7**, the drilling fluid properties were similar to what was designed during the pre-planning of the well and what was tested in the laboratory prior to the trip. After logging the well for two days, the bottoms-up sample exhibited excellent stability and only required pH adjustment.

Lessons Learned #2

Due to an insufficient shoe test, drilling was halted when the ECD approached the shoe's test pressure. After circulating bottoms-up, high gas indicated that the pore pressure was higher than anticipated, requiring higher density fluid. As the density of the fluid was increased to control the gas, 500 bbl (79 m^3) of fluid were lost to the formation.

Losses stopped when the flow rate was reduced, thus reducing the ECD of the fluid. At that point, the liner was run, relying on engineering software to predict the optimal running speed. The engineering software had been used extensively during the drilling of the 8½-in. section to predict ECD and SPP. Determining the ECD of the fluid at the point that no more mud losses were occurring gave a starting point (fracture pressure) for surge modeling. A stair-step approach to liner running speeds predicted that the slowest running speed of the 7-in. liner would be between the 9⅝-in. casing shoe and the loss zone. Subsequently while running the 7-in.liner, no drilling fluid was lost to the formation.

The second HP/HT section of the well

The second HP/HT section of the well began by tripping into the well to drill the cement. While tripping in the hole to drill cement, the string began to take weight at the top of the 7-in. liner. The cement appeared to be in a thin layer around the inside of the 7-in. liner. This had to be drilled out all the way to the liner shoe. Parts of the cement spacers and the cement returns were observed while drilling out of the liner.

The cement returns were sometimes large pieces that the mud carried out of the hole, but much of the cement was ground up into a fine powder by the PDC bit and dispersed into the mud. The shaker screens on the shale shakers were not fine enough to separate the cement from the drilling fluid. The system was treated with sodium bicarbonate to lower the calcium content, but the rising HP/HT filtrate values and the thickening mud were not improved.

After drilling out of the liner shoe and new formation was drilled, a leakoff test was performed. Drilling commenced and the drilling fluid was treated with HP/HT specialty products. An increase in the flowline temperature caused a raise in the evaporation rate of water in the drilling fluid system. The water lost by evaporation was causing more than 30 bbl/day (4.7 m^3/day) of water losses from the active system; subsequently, the drilling fluid was dehydrating. Water and fluid loss-reducing products were added to control the viscosity and HP/HT fluid loss of the drilling fluid. Shaker screens were changed to a finer mesh to separate the fine cement from the drilling fluid system. Removing the fine solids helped to thin the drilling fluid, after which dilution became more effective at controlling the viscosity of the fluid.

Drilling continued, increasing the drilling fluid density as needed. At TD of the well, the mud weight was increased to 18.0 lb_m/gal (2.16 sg) prior to tripping out of the hole for logs. Initially, logs failed to reach bottom and a subsequent trip indicated carbonate contamination. To combat the effects of carbonate contamination, 500 bbl (79 m^3) of mud containing a 25% transfusion or displacement was spotted on bottom of the hole while pumping out of the hole for logs. Wireline logs were then successfully run recording a BHST of 350°F (177°C).

Lessons Learned #3

Through the rapid drilling of the section there was insufficient time spent in the conditioning of the drilling fluid prior to reaching TD and the subsequent logging operation. The laboratory test results of the fluid left in the wellbore during the first and second logging runs show how the fluid was affected as it was exposed to the high-static temperature.

The fluid with the 25% transfusion allowed the logging tools to reach bottom and exhibited excellent viscosity after the aging tests as seen in **Table 8**.

Conclusions

- Having personnel with experience in using HP/HT specialty products and following HP/HT operational protocol can make the difference between the success and failure of a drilling operation.
- Basis of Design reviews are an irreplaceable aid in completing the design of a fluid for HP/HT wells.
- Accurate temperature modeling can be done prior to the drilling of HP/HT wells to aid in determining critical points in the well.
- Accurate HP/HT pressure loss modeling can be done with actual temperatures from the well.
- Fluid stability with an HP/HT WBM can be achieved in the field and qualified through laboratory aging tests.

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Nomenclature

PDC = *polycrystalline diamond compact*
WBM = *water-based mud*
OBM = *oil-based mud*
SBM = *synthetic-based mud*
HPWBM = *high-performance water-based mud*
BHA = *bottomhole assembly*
ECD = *equivalent circulating density*
ESD = *equivalent static density*
SPP = *standpipe pressure*
PAH = *polycyclic aromatic hydrocarbon*
P_{ow} = *partition coefficient between octanol and water*
QED = *Quality Element Deployment*
BOD = *basis of design*
MSDS = *material safety data sheet*
IADC = *international association of drilling contractors*
HP/HT = *high pressure / high temperature*
BOP = *blowout preventer*
TD = *total depth*
BHST = *bottomhole static temperature*
LOT = *leakoff test*
FLCA = *fluid loss control agent*

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Tables

Table 1: Environmental Regulatory Testing Requirements for Drilling Fluids Use Offshore Brazil

Water-Based Fluid	Test Method	Specification
Acute Toxicity (MJ)	NBR 15.308	>30,000 ppm
Chronic Toxicity (LV)	NBR 15.350	Information only

Non-aqueous Fluid	Test Method	Specification
Acute Toxicity (MJ)	NBR 15.308	>30,000 ppm
Chronic Toxicity (LV)	NBR 15.350	Information only
Biodegradability	OECD 306	>60%
Log Pow	OECD –guideline 117	>7.0
PAH	NBR ISO/IEC 17025:2005 sob o nº CRL 0178	< 10 ppm

MJ – *Mysidopsis juniae* (Crustacea-Mysidacea)
LV – *Lytechinus variagatus* (Echinodermata-Echinoidea)
CENO – concentration of effect not observed
CEO – concentration of effect observed
VC – chronic value

Table 2: Comparing HP/HT Water-Based Mud Properties of Like Wells to the Properties of an HP/HT WBM Obtained in Laboratory Tests

	BHST	Density	Plastic Viscosity	Yield Point	API Fluid Loss	HP/HT Fluid Loss
Units	°F	lb_m/gal	cP	$lb_f/100ft^2$	cm^3/30 min	cm^3/30 min
Lab Results	**380**	**17.0**	**57**	**20**	**3.5**	**13.0**
Well 1	320	16.1	30	31	7.8	31.5
Well 2	400	16.45	22	6	7	28.8
Well 3	400	17.1	27	25	10	18.6
Well 4	420	17.5	27	30	6.2	17.0
Well 5	420	18.1	91	27	0.8	18.0

Table 3: Comparing HP/HT Oil-Based Mud Properties of Like Wells to the Properties of an HP/HT WBM Obtained in Laboratory Tests

	Density	Plastic Viscosity	Yield Point	HP/HT Fluid Loss	HP/HT Temp
Units	lb_m/gal	cP	$lb_f/100ft^2$	cm^3/30 min	˚F
Lab Results	**17.0**	**59**	**23**	**2.0**	**300**
Well 1	16.0	46	22	4.0	350
Well 2	18.0	57	15	2.9	300
Well 3	17.0	52	12	4.8	350
Well 4	16.5	38	13	2.6	300

Table 4: Laboratory Results of HP/HT Water-Based Mud and HP/HT Oil-Based Mud Demonstrate the Stability of Both Fluids after Being Exposed to High Temperatures for Extended Time

Properties	**Units**	**After 88 hours @380 ˚F**	
		WBM	OBM
Density	lb_m/gal	17.0	17.0
Plastic Viscosity @120˚ F	cP	66	75
Yield Point @120˚ F	$lb_f/100ft^2$	23	21
API filtrate	cm^3/30 min	2.6	--
HP/HT @300˚ F	cm^3/30 min	14.0	2.4
HP/HT on 20 micron disk	cm^3/30 min	40.0	12.0

Table 5: TD Predicted Temperature and Pressure Loss from HP/HT Modeling at 452 Gal/Min

Parameters	Units	WBM	OBM
BHCT	˚F	309	347
Flowline Temperature	˚F	125	119
ECD	lb_m/gal	18.04	18.33
ESD	lb_m/gal	17.02	17.19
SPP	psi	4,513	4,896

Table 6: Daily Reporting Requirement of the Maximum Mud Weight Potential and Limiting Products for the Capability to Build Volume

Maximum mud weight potential: 19.44 lb_m/gal							
Remaining volume to build: 1,094 bbl							
Name	**Watch**	**A**	**B**	**C**	**D**	**E**	**F**
Bentonite		8	17,600	3.32	5,301	6	2,933
FLCA 1		**72**	**1,800**	**1.93**	**933**	**2**	**900**
FLCA 2		186	9,300	3.76	2,473	4	2,325
FLCA 3		193	9,650	4.1	2,354	4	2,413
Fluid Stabilizer		185	4,625	3.21	1,441	2	2,313
Lime		248	10,935	0.93	11,758	3	3,645
Magnesium Oxide		373	20,558	5.22	3,938	3	6,853
H2S Scavenger		100	5,000			1	5,000

A = Final Inventory Amount
B = Inventory Weight [lb]
C = Current Actual Concentration [ppb]
D = Volume to Build [bbl]
E = Planned Concentration [ppb]
F = Possible Volume to Build [bbl]

Table 7: Fluid Properties of 8½-In. Fluid when Exposed To High Temperature during Logging Operations

	Pre-well planning	**Lab Prediction**	**Field Results**
Temperature	380F	375F	350F
Time	88 hours	40 hours	70 hours
Mud Weight, ppg	17.0	16.5	16.6
Plastic Viscosity, cP	78	32	46
Yield Point, $lb_f/100ft^2$	10	10	20
6/3 rpm, readings	4 / 3	3 / 3	9 / 7
Gel Strength, $lb_f/100ft^2$	4 / 12	3 / 6	7 / 24
API, cm^3/30 min	2.4	4.2	3.8
HP/HT @ 300F, cm^3/30 min	26.0	26.0	25.0

Table 8: Fluid Properties of the 18.0 Lb_m/gal (2.16 sg) Fluid Exposed to High Temperature, 375°F (191°C), During the Logging Operations in the 6-in.Section of the Well

Time, hours	Initial	16 hours	40 hours
--- First logging run ---			
Plastic Viscosity, cP	28	30	27
Yield Point, $lb_f/100ft^2$	18	34	12
6/3 rpm, readings	7/6	15/14	4/3
Gel Strength, $lb_f/100ft^2$	8/49	21/58	4/48
API, cm^3/30 min	2.8	5.3	5.0
HP/HT @ 300F, cm^3/30 min	54	42	46
--- Fluid with 25% transfusion ---			
Plastic Viscosity, cP	26	27	24
Yield Point, $lb_f/100ft^2$	4	10	12
6/3 rpm, readings	2/2	5/4	7/6
Gel Strength, $lb_f/100ft^2$	3/16	4/29	6/45
API, cm^3/30 min	2.2	3.3	3.9
HP/HT @ 300F, cm^3/30 min	42	48	46

Figures

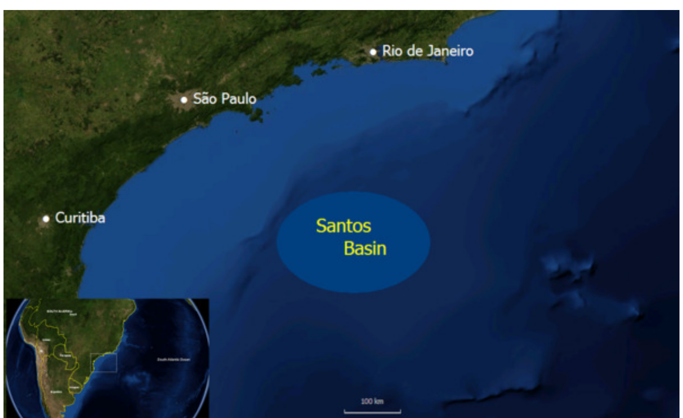

Figure 1: Santos Basin offshore Brazil[1]

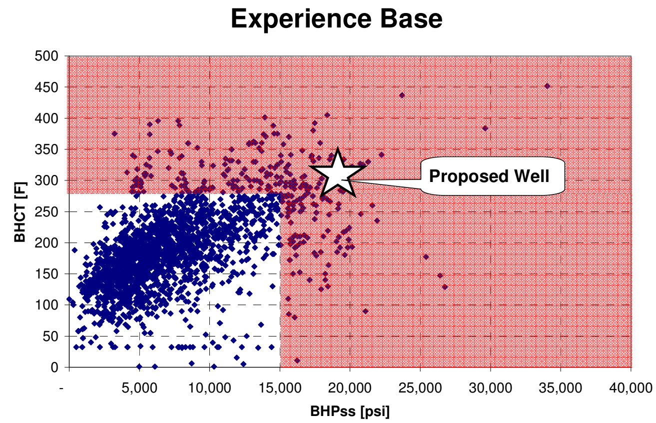

Figure 2: Experience base indicating the proposed well is located within the "critical well" criteria

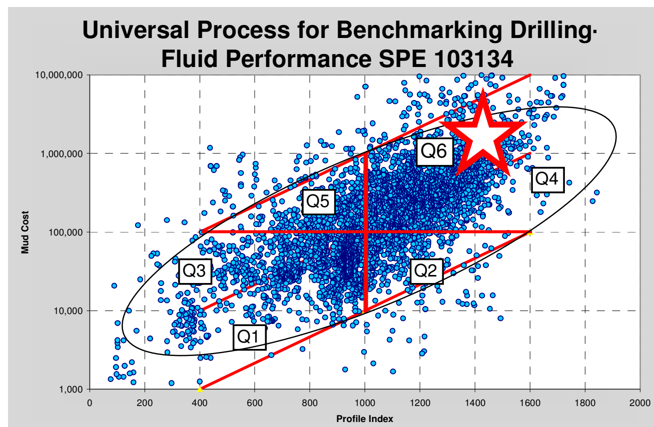

Figure 3: Well placement compared to wells in a completed well database

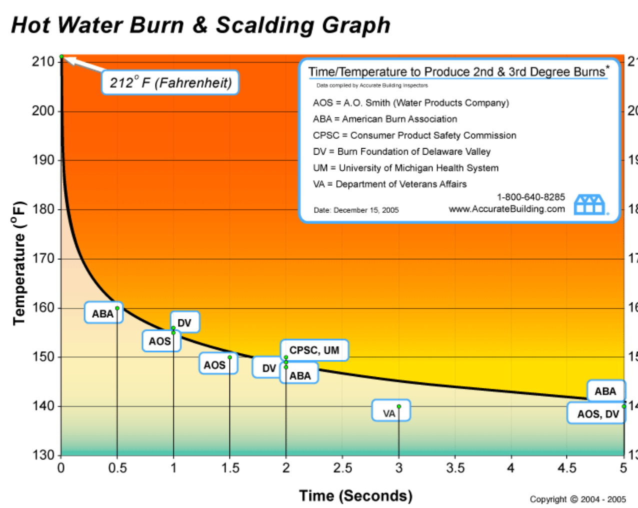

Figure 4: As temperature increases, the time required to scalding is reduced rapidly[8].

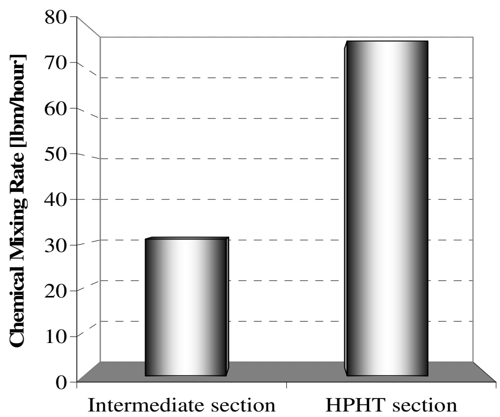

Figure 5: Average mixing rate [lb_m/hour] of chemicals for pH control in WBM for intermediate and HP/HT sections of three wells

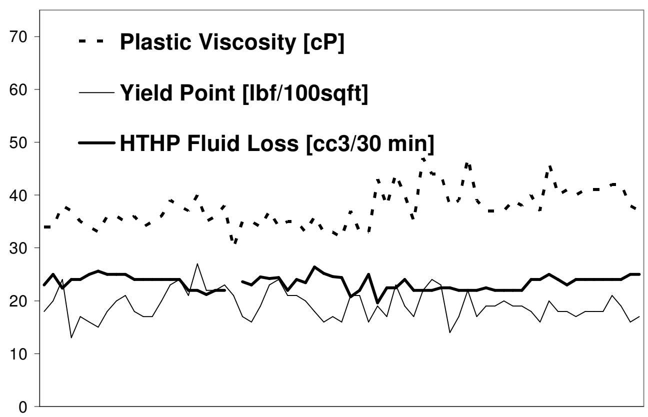

Figure 6: Drilling Fluid properties in the 8½-in. section

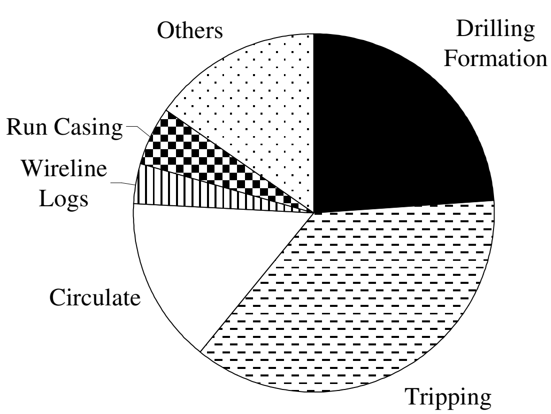

Figure 7: IADC time breakdown of the 8½-in. section