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HPWBM Exceeds SBM Performance in Narrow Pore Pressure/ Fracture Gradient Environments

Bonsall Wilton and Randal LaVergne, Ambar Lone Star Fluid Services; Brian Logan, Apache Corporation

Abstract

The application of High Performance Water Base Muds (HPWBM) in narrow fracture gradient/pore pressure environments can offer Operators significant well cost savings. A HPWBM used to drill the South Timbalier 308 A-5 well improved drilling performance as compared to the synthetic base mud (SBM) applied in the previous four wells. The tight tolerance between fracture gradient, pore pressure and fluid density provided a very narrow drilling window in which to perform. Critical to the success of this well was the improved leak-off tests (LOT) attributed to the use of HPWBM relative to SBM that resulted in fewer instances of lost circulation. Also, when losses occurred with HPWBM, the volume of loss was significantly reduced and more easily controlled. This in turn allowed casing setting depths to be extended, resulting in the elimination and downsizing of two casing strings as compared to the previous wells. The inhibition from the HPWBM, in conjunction with control drilling, resulted in minimal non-productive time associated with gumbo clay, elevated ECD and lost circulation. The application of prudent drilling practices along with the use of HPWBM resulted in 21 fewer average drilling days and $8MM less drilling cost as compared to the average performance of the previous four wells drilled with a synthetic fluid.

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Introduction

Synthetic base drilling muds are generally accepted as the drilling fluids of choice in deepwater applications or where wellbore stability conditions dictate the need for a highly inhibitive fluid. While very effective, the downside of using a SBM is a higher frequency of lost circulation as compared to HPWBM at similar densities. Lost circulation with synthetic fluids has been identified as the number one mud related issue in deepwater environments. This is directly related to lower fracture gradients, tight casing/hole clearances, and synthetic fluids made denser and more viscous by temperature and pressure environments associated with deepwater drilling.[1,2] This usually results in higher well costs associated with additional casing strings, lost circulation, stuck pipe, sidetracked wellbores or a combination of these conditions. Also, studies have shown a significant difference between the ECD values of SBM and various water base muds.[3] In conjunction with proper drilling practices, a HPWBM can be successfully used in many instances to mitigate these unscheduled events and reduce well costs. The South Timbalier 308 case history explores the effects of applying a HPWBM instead of a SBM and the impact such a change can have on casing design and total well economics.

South Timbalier 308 Project Design

The ST 308 project to date consists of 5 wells drilled in 484’ water depth on the flank of a salt dome, with total well depths ranging from 18,000’ TVD to 20,470’ TVD. The drilling objective is typically a series of sands within a +/- 1,000’ thick lower Miocene interval. The first three wells (#1, #2 and #3) drilled through a thin (150’ to 200’ thick) salt section. Well #4 was drilled without encountering salt. In addition to salt related problems, the wells in the area experienced severe gumbo problems, packing off, excessive backreaming, “ballooning” formations, lost circulation, hole cleaning problems and well control issues. Three different floater rigs were used on the first four wells with another Operator, and a platform rig was used on the A-5 well with Apache Corporation as the Operator. The drilling fluid selected for the first four wells was a SBM from three different drilling fluid companies, while a HPWBM was used on the A-5 well. The mud density at total depth on all five wells ranged between 16.6 ppg and 17.3 ppg, within a bottom hole temperature environment of approximately 250°F.

In the planning of the A-5 well, the relationships between pore pressure, actual mud density, lost circulation instances, predicted fracture gradient and leak-off test data were evaluated. Most hole sections included critical intervals where the difference between the required mud density and fracture gradient was 1.0 ppg or less. It was common in the offset wells for lost circulation to occur at pressures significantly less than the predicted fracture gradient, and at pressures far below the leak-off tests at the prior shoe. In many instances, lost circulation occurred at (or below) the anticipated mud density requirement for that interval. **Figure 1** shows the comparative TVD data of the first four wells with respect to estimated fracture gradient, actual leak-off tests, depths where significant lost circulation occurred, depths of well control incidents and anticipated mud density for the A-5 well. The relationship of the curves on **Figure 1** demonstrates the impact that lost circulation has on casing design and the resultant well cost. The ability to deal with lost circulation incidents and extend one casing seat by as little as 0.5 ppg can have a significant impact on future casing setting depths and the overall well design.

ST 308 #1 thru #4 Wells Summary

The unscheduled events experienced on the offset wells included lost circulation, wellbore instability, hole cleaning problems, stuck pipe, ballooning and well control issues. All four wells maintained an appropriate concentration of lost circulation material in the drilling fluid to deal with anticipated loss zones. Additional LCM products at higher concentrations were added in sweep form while drilling to aid in controlling losses. Typical products employed included cellulosic fiber, graded calcium carbonate, nut hulls and graphitic carbon. When massive losses occurred, attempts to cure the losses were made with various activated lost circulation pills or cement.

The #1 well is considered exploratory and reached TD in a salt section. The #2 and #3 wells both encountered salt intervals of approximately 150' to 200' in thickness at roughly 13,000' TVD. The #4 well avoided salt altogether.

It is important to note that the #3 and #4 wells benefited from a significant learning curve from the previous two wells. All four wells employed a similar casing design to handle the anticipated pore pressure and mud density requirements. **Figure 2** illustrates the typical casing design used on these wells and the improvement in performance with respect to mud density, days and total well cost between the first 4 wells.

The #1 well was a vertical exploration well and suffered over 3,700 bbls in downhole losses of SBM. Other downtime was attributed to hole cleaning and wellbore instability problems associated with insufficient mud density and a salt water flow. In all cases, lost circulation occurred below the leak-off test equivalent mud weight. Typically, the actual mud density was within 0.6 ppg to 1.9 ppg of the LOT equivalent, depending on the well interval. Equivalent circulating densities, according to available PWD data, varied from 0.2 ppg to 0.5 ppg above surface mud densities. In the upper hole sections, mud losses occurred throughout the interval. In the deeper sections of the well, losses began either at interval TD, while running and cementing casing or shortly after drilling out of the last casing/liner section. The #1 well required 141 cumulative days to reach total depth of 18,063' MD/TVD at a cumulative cost of approximately $30MM, including the deepening procedure with another rig. Total drilling fluid cost for the well, including losses, was about $5.3MM.

The #2 well, a directional well with maximum inclination of 30˚, incurred downhole losses approaching 14,000 bbls of SBM. Although this well experienced similar problems as the first well, the most significant impact to well cost was a well control event that caused massive lost circulation and eventual sidetracking of the original wellbore. This was also the deepest well of the four. The #2 well required 137 cumulative days to reach total depth of 21,250' MD/20,470' TVD at a cumulative cost of approximately $31.4MM, including the sidetrack. Total drilling fluid cost for the well, including losses, was about $5.2MM.

The #3 well was an "S" shape directional well with a maximum inclination of approximately 30˚. This well also experienced problems similar to the first well, with a well control event at TD resulting in severe lost circulation and eventual plugging of the bottom interval. A total of 6,500 bbls of SBM was lost downhole with 3,000 bbls associated with the well kick. This well required 72 cumulative days to reach total depth of 20,960' MD/19,812' TVD at a cumulative cost of approximately $17.8MM. Total drilling fluid cost for the well, including losses, was about $2.48MM.

The #4 well was also an "S" shape directional well with a maximum inclination of approximately 30˚. Most of the losses that occurred on this well were associated with running and cementing casing. Approximately 4,200 bbls were lost during these operations. The concentration of various LCM materials was maintained in the system to reduce loss circulation potential. Drilling practices were also employed with respect to controlled rate of penetration and backreaming to further reduce potential losses. This well required 62 cumulative days to reach total depth of 20,370' MD/19,740' TVD at a cumulative cost of approximately $17.0MM. Total drilling fluid cost for the well, including losses, was about $2.1MM.

Apache South Timbalier 308 A-5 Well Design

Apache's ST 308 A-5 well was similar in design to the prior four offset wells. The directional plan was a 27° build and hold design to a total depth of 20360' MD/ 18,500' TVD.

The ST 308 A-5 well design had to address the same downhole challenges as the first four wells, but also had to account for surface equipment limitations not present with the offset wells. The most significant issue was the use of a 3000 HP platform rig instead of a semi-submersible rig. This imposed obvious limitations with regards to logistics, deck space, cuttings handling, the circulating system, drillstring design and hydraulics. While these limitations affected many aspects of the overall well design, the two most significant conclusions were:

1. The use of oil base mud or synthetic oil mud would not be possible because of insufficient deck space for cuttings handling, and
2. With the use of water base mud, drilling rate would have to be controlled to improve hole cleaning and to reduce ECD related to gumbo, packing off, and loading of annulus with cuttings.

In light of these limitations, it was expected and accepted that the number of days to drill the A-5 well would likely exceed the time required for the #3 and #4 offset wells, especially when considering the other Operator's benefit from a four well learning curve. Therefore, Apache's focus was on maintaining the lowest possible daily cost spread (i.e. keep it simple), avoiding unscheduled events by not getting in a hurry, and planning for the possible extension of casing seats and elimination of one or more casing/liner strings. It should be noted that, although Apache was optimistic about extending casing seats and eliminating casing strings by using HPWBM, the planned casing program included the same casing design as was required in the prior four offset wells. It was anticipated that 105 days would be required to drill to TD, yet the planned total well cost was an aggressive $18.0MM.

The inability to use oil base or SBM due to rig space limitations, in conjunction with prolific gumbo problems in offset wells, made it imperative to select a HPWBM for the A-5 well. Although there was no direct comparison for HPWBM in the immediate area, Apache had confidence in using HPWBM because of favorable past results in other gumbo prolific areas. Although it was difficult to quantify the possible cost savings or justify modification to the planned casing design, Apache recognized the potential for HPWBM to provide improved leak-off tests, lower ECD's, reduced potential for lost circulation and greater flexibility in dealing with losses when they occurred.

The drilling fluid selected for the well was Ambar Lone Star's DFX high performance water base fluid, which is a fresh water low pH deflocculated system with rate of penetration and lubricant surfactant components added in varying concentrations as dictated by the wellbore conditions. In addition to the surfactant package, potassium acetate was added for clay inhibition.

The DFX drilling fluid system is designed to be a very flexible system with respect to addition of product and surfactant components. Typically, the DFX package components are preblended in a specific ratio designated for a particular well and added to the mud system at the desired concentration. A 6% to 8% by volume concentration is usually maintained with the ratio of components held constant. However, there have been wells where this concentration has been above 12% by volume. Also, individual components can be added to alter the relative ratio of the DFX surfactants depending on wellbore conditions. **Table 1** shows the composition of the drilling fluid used on the A5 well.

Apache South Timbalier 308 A5 Well Results

The success of the ST 308 A-5 well can be attributed to improved leak-off test results, significantly reduced lost circulation through the application of HPWBM, the flexibility of dealing with lost circulation due the use of HPWBM, and controlled drilling rate to lessen the chances for lost circulation due to elevated ECD's. The above benefits allowed casing setting depths to be extended beyond the plan and, in turn, resulted in the elimination of two casing strings relative to the previous four wells.

Comparing the A-5 well schematic in **Figure 3** to the typical offset well schematic in **Figure 2** shows that the 26" casing and 11.875" liner strings were eliminated in the A-5 well. This was achieved largely because improvement in the fracture gradient helped control mud losses and allowed the 16" and 13.625" casings to be set deeper than planned. Eliminating the 11.875" casing also eliminated the need for underreaming and tight tolerance wellbore conditions in the 12-1/4" and 8-1/2" hole sections, which further reduced lost circulation potential and allowed higher mud weights to be used without exceeding ECD limits.

The A-5 well required 86 days to drill to 20,239' MD/ 18,413' TVD, which also included approximately nine nonproductive days due to hurricane evacuation. This was 19 days less than the AFE and 21 days less than the average of the previous four wells, but 19 days longer than the average of the two best previous wells. Excluding the hurricane evacuation, the A-5 was only 10 days longer than the best average well performance. The additional time can be attributed, at least in part, to the logistics of using a platform rig instead of a semi-submersible rig.

The total well cost of the A-5 was $15.2 MM, which was $2.8MM under AFE, $8.8MM less than the average of the previous four wells and $1.8MM less than the best offset to similar depth. The cost reduction is the result of the elimination of two casing strings, less mud loss, and lower overall daily operating cost.

As with the prior four wells, a program for sweeps and maintenance of lost circulation materials in the drilling fluid was implemented. These materials included calcium carbonate, cellulosic fiber and nut hulls. Only four instances of lost circulation were noted, two of which were during cementing operations after running casing. Another loss zone was in the 12.25" hole section while drilling, and circulation was quickly regained after spotting lost circulation material. The last instance of lost circulation occurred in the 8.5" hole section, and required spotting an activated pill. The activated pill was successful and drilling continued to total depth. Overall, less than 1,600 bbls of HPWBM was lost during the A-5 well, as compared to an average of over 5,300 bbls of synthetic mud lost on the two best offset wells and an overall average of 7,100 bbls per well for the prior four wells. The total drilling fluid cost for this well was $2.3MM, including losses.

Other noteworthy accomplishments are:

1. After successfully drilling the A-5 well, the well was plugged and sidetracked for geologic reasons. After cutting a window in the 13 5/8" casing at 9,584' MD, the sidetrack was drilled to 19,548' MD/18,500' TVD and successfully cased for completion. Like the original hole, the sidetrack was completed under AFE with regard to both days and cost.
2. While drilling the sidetrack hole, two hurricanes caused extended interruptions with long open hole intervals exposed. Hurricane Katrina caused a 14 day delay at 15,497' MD with 5,913' of open hole exposed. After restoring operations, the open hole was cleaned out without major problems and the 9 7/8" liner was run to bottom. One week later, after drilling to 17,568' MD, Hurricane Rita caused another 7 day delay with 1,540' of 8.5" open hole exposed. Again, the hole was reclaimed with no problems after restoring operations and drilling continued trouble free to TD of 19,548' MD/18,500' TVD.

Conclusions

The success of the ST 308 A-5 well was accomplished despite the additional challenges associated with a platform rig. The inability to use SBM due to deck space limitations shifted the focus to HPWBM, and inspired the implementation of procedures to manage the risks while taking advantage of the benefits. The ability to reclaim open hole after extended hurricane delays, as well as the ability to drill highly sensitive gumbo shales without major problems, proves that HPWBM has sufficient inhibition for this area. The use of HPWBM, in conjunction with good drilling practices, resulted in (1) improved fracture gradients at shallower depths, (2) fewer instances of lost circulation and lesser volume of mud lost, (3) enhanced ability to cure mud losses when they occurred (4) the extension of casing setting depths, and (5) the elimination of two casing strings compared to the offset wells. The overall result was reaching total depth in approximately the same number of days and at a significantly lower cost compared to the four prior wells drilled by another Operator with SBM.

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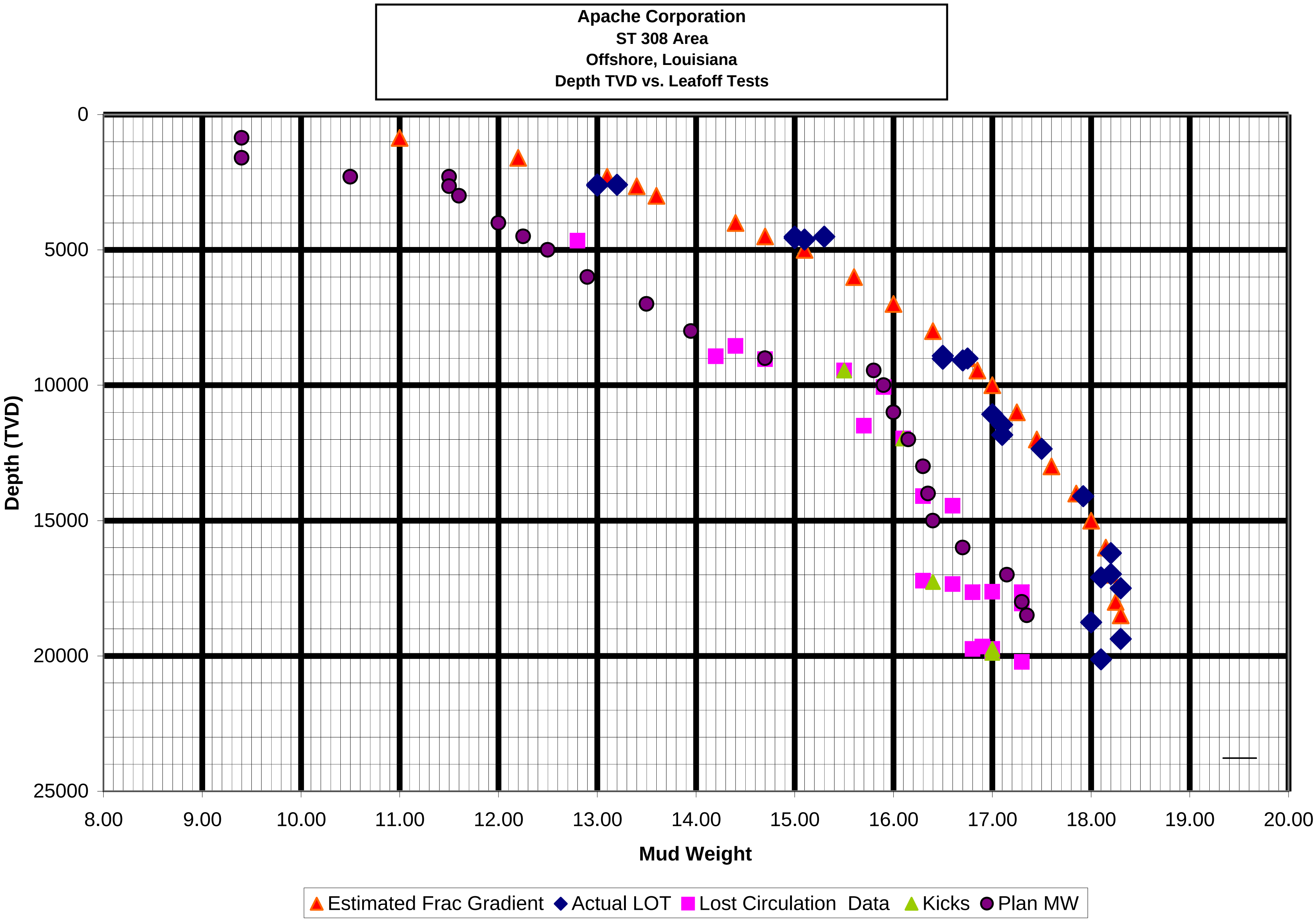
AVERAGE HPWBM COMPOSITION

DFX Surfactants	**6% - 8% v/v**
Deflocculant	**2 - 6 ppb**
Lignite	**10 – 14 ppb**
Sulfonated Asphalt	**4 – 6 ppb**
PHPA	**1.5 – 2.0 ppb**
Potassium Acetate	**1.0 ppb**

Table 1



Apache Corporation
ST 308 Area
Offshore, Louisiana
Depth TVD vs. Leafoff Tests
0
5000
10000
15000
20000
25000
Depth (TVD)
8.00
9.00
10.00
11.00
12.00
13.00
14.00
15.00
16.00
17.00
18.00
19.00
20.00
Mud Weight
Estimated Frac Gradient
Actual LOT
Lost Circulation Data
Kicks
Plan MW

FIGURE 1

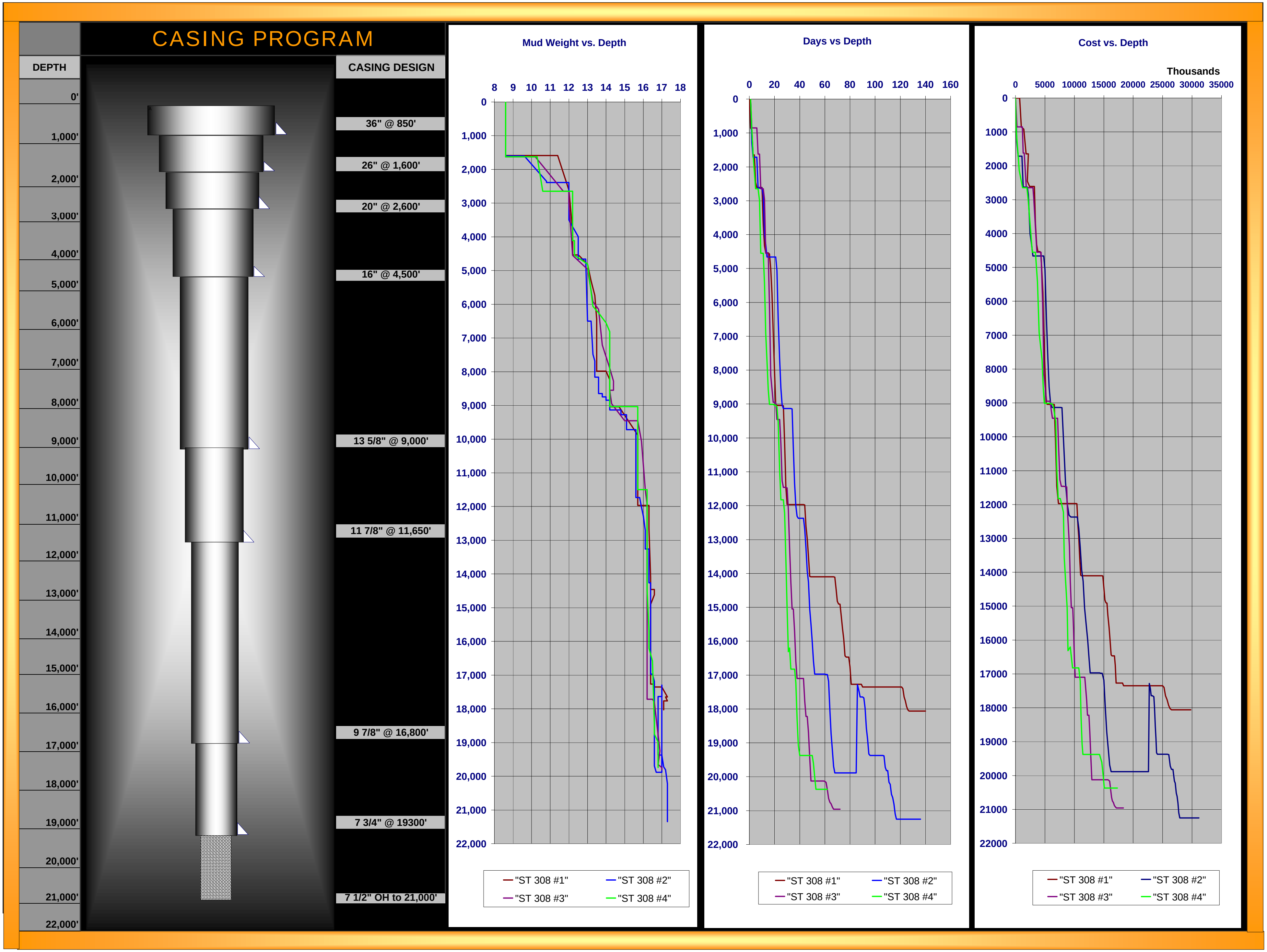
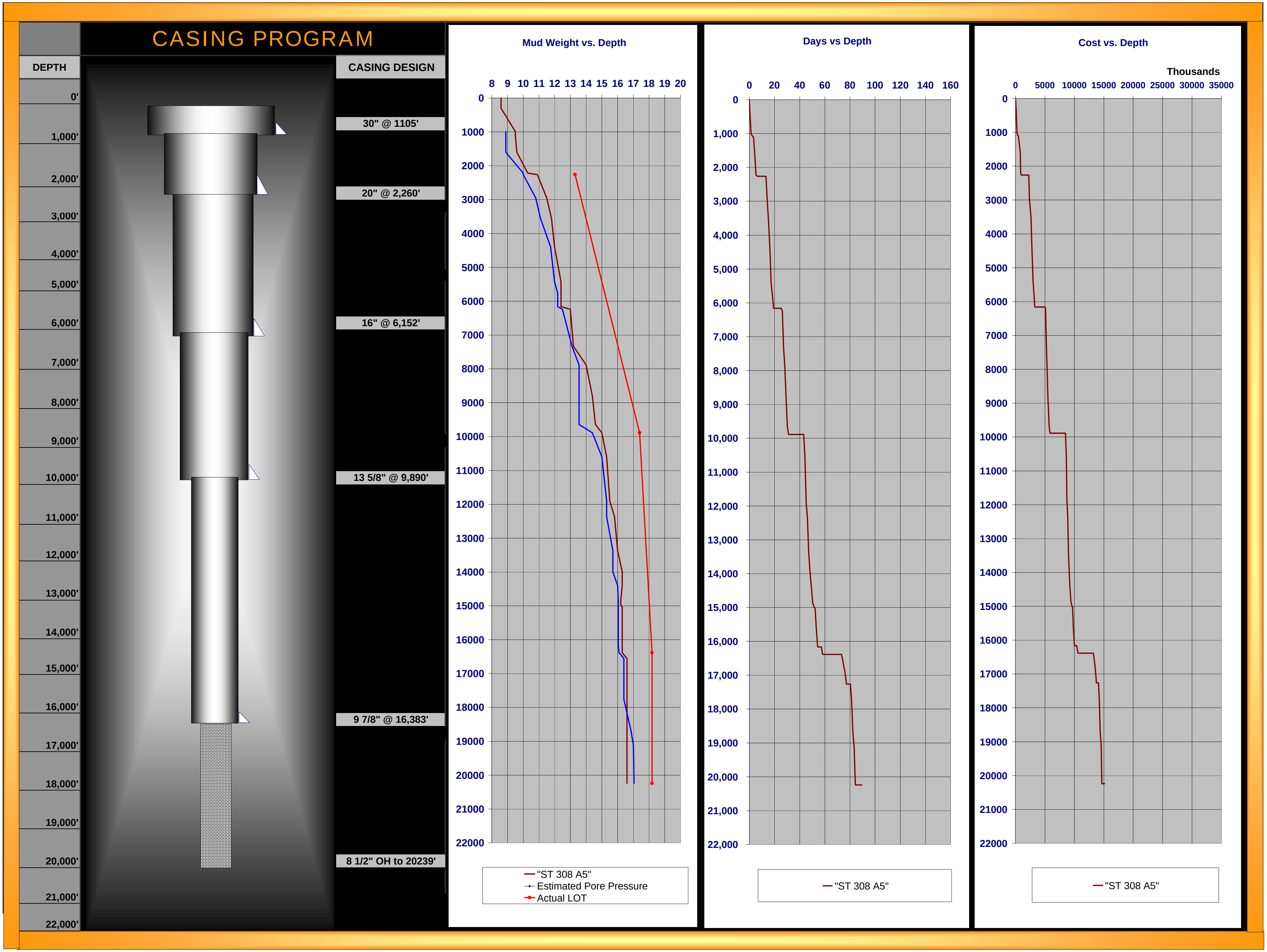

CASING PROGRAM
DEPTH
CASING DESIGN
0'
1,000'
2,000'
3,000'
4,000'
5,000'
6,000'
7,000'
8,000'
9,000'
10,000'
11,000'
12,000'
13,000'
14,000'
15,000'
16,000'
17,000'
18,000'
19,000'
20,000'
21,000'
22,000'
36" @ 850'
26" @ 1,600'
20" @ 2,600'
16" @ 4,500'
13 5/8" @ 9,000'
11 7/8" @ 11,650'
9 7/8" @ 16,800'
7 3/4" @ 19300'
7 1/2" OH to 21,000'
Mud Weight vs. Depth
Days vs Depth
Cost vs. Depth
Thousands
"ST 308 #1"
"ST 308 #2"
"ST 308 #3"
"ST 308 #4"

FIGURE 2



CASING PROGRAM
DEPTH
CASING DESIGN
0'
1,000'
2,000'
3,000'
4,000'
5,000'
6,000'
7,000'
8,000'
9,000'
10,000'
11,000'
12,000'
13,000'
14,000'
15,000'
16,000'
17,000'
18,000'
19,000'
20,000'
21,000'
22,000'
30" @ 1105'
20" @ 2,260'
16" @ 6,152'
13 5/8" @ 9,890'
9 7/8" @ 16,383'
8 1/2" OH to 20239'
Mud Weight vs. Depth
8 9 10 11 12 13 14 15 16 17 18 19 20
"ST 308 A5"
Estimated Pore Pressure
Actual LOT
Days vs Depth
0 20 40 60 80 100 120 140 160
"ST 308 A5"
Cost vs. Depth
Thousands
0 5000 10000 15000 20000 25000 30000 35000
"ST 308 A5"

FIGURE 3