



Flexible Drilling Fluid Helps to Drill High Pressure Wells Offshore Louisiana

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Abstract

A versatile high performance water-based drilling fluid system formulated to meet the requirements of complex high angle wellbores through highly reactive and abnormally pressured “gumbo” shale was employed to efficiently drill three challenging wells in the High Island A325 area of the Gulf of Mexico. Among factors leading to selection of this system were rig space and equipment limitations that eliminated the possibility of oil- or synthetic-based systems, and the water-based system’s inherent ability to be enhanced to address changing operational demands as they occur, while allowing wide ranging pre-treatment options for anticipated downhole challenges that lie ahead.

The water-based system was designed around three unique components—a methyl glucoside-based shale stability additive, a complex ester-based rate-of-penetration (ROP) enhancer and a humalite drilling fluid conditioning agent—that provided enhanced performance in this fit-for-purpose system, resulting in excellent lubricity and high penetration rates.

Prudent drilling practices, aided by drilling fluid performance, planning and management, resulted in excellent wellbore conditions while eliminating non-productive time for the operator. Field time-to-drill records were attained while AFE costs were met.

Introduction

The High Island A325 area presents operators with some of the toughest drilling challenges found in the GOM, including shallow pressured gumbo and severely depleted zones. Modern complex directional schemes magnify the operational demands of this geology.

While the well-known performance attributes of oil- or synthetic-based systems for this application make them a popular choice for operational efficiency, space and equipment limitations—particularly on jack-up or small platform rigs commonly used on shelf (shallow water) wells—often require operators to compromise by choosing a water-based fluid that requires minimal storage space and surface equipment. Maximizing drilling fluid performance in these cases is key to preserving operational efficiency.

The operator anticipated demanding conditions at High Island A325. Previous wells in the area had

encountered high-pressured gumbo shale from 3200 to 5500 ft TVD. Many prior attempts to control those formations had centered primarily on increasing fluid density; with densities varying widely from 10.0 to 15.2 lb/gal in the production interval, but higher fluid densities had offered limited aid in stabilizing the shales. Shale stability issues had plagued previous wells, with common resultant problems including stuck pipe and limited ROP.

Three complex high-angle wells were planned.

Fluid Requirements and Selection

The operator performed careful analysis of previously drilled wells in the area of interest, and established the following criteria for drilling fluid selection for the planned wells:

- Water-based fluid that required minimal storage space or deck space for extra equipment;
- Optimized ability to achieve high penetration rates;
- Maximized lubricity for pressure depleted zones;
- Extreme inhibition for reactive water sensitive shales;
- Ability to accommodate fluid densities in excess of 15 lb/gal;
- Ability to tolerate common contaminants (salt, temperature, solids, cement, calcium, etc.)

A versatile drilling fluid system was chosen that utilized a methyl glucoside-based shale stability additive along with a complex ester-based ROP enhancer and a humalite fluid control and conditioning agent. It was felt that this system could provide adequate inhibition to efficiently drill the pressured gumbo formations as well as near-OBM type lubricity.

Logistics Arrangements and Planning

A platform rig with limited surface volume and mixing capabilities was to be used to drill the three wells. A decision was made to pre-mix the drilling fluid at the drilling fluid provider’s Cameron shore base to prevent delays in mixing time on the rig. Limited deck space on the rig also made necessary the utilization of one workboat for sack and liquid storage. The rig’s active pit volume was only 330 bbl and reserve volume storage was 150 bbl. Volumes were very tight. The pre-mix

volumes included the methyl glucoside-based shale stability additive, complex ester-based ROP enhancer and a humalite fluid control agent. All mixes were prepared unweighted.

Mud weight analysis and prediction was the first focus of the well plan. Projected mud weights for all of the wells were based upon pressure profiles from wells previously drilled from the platform. Pressured gumbo-type formations and depleted sands were expected. Pressure profile (Figure 1) showed offset mud weights as high as 15.1 lb/gal. Anticipated pressured regimes included a 12 lb/gal equivalent mud density at 3830 ft, increasing to 15 lb/gal equivalent to 7000 ft. Pre-planning indicated a need for a mud weight at or near the pore pressure to minimize possible potential losses in depleted zones. In the composite pore pressure analysis (Figure 2) mud weight prediction was determined.

Drilling Fluid Performance and Operational Review

Well A-7 was drilled first, followed by A-8 and A-9. In each well, displacement was made to the high performance water-based mud after surface pipe was set. The lubricating and shale inhibition qualities of the fluid were required to provide efficient penetration rates and wellbore stability throughout the interval. Lab data (Table 1) indicating lubricating properties of the system indicate that the methyl glucoside shale stabilizing additive with a complex ester ROP enhancer and a humalite product for rheological and fluid loss control improved lubricity to acceptable levels.

A rapid increase in pore pressure was anticipated just below the PL6-1 sand, which was penetrated from +/-3055 to 4600 ft TVD. Pore pressure increased from 11.0 to 13.0 lb/gal immediately after drilling this sand. On the A-9 well, higher pore pressure (13.5 lb/gal) in this interval was anticipated. Practical considerations regarding weight-up prompted well planners to begin raising density early, resulting in mud densities higher than required in the upper section of the interval. On the other two wells, however, that was not the case—and actual fluid density was maintained at or slightly below calculated pore pressure (Table 2).

On A-9, a fault was crossed after drilling out of casing at 6060 ft and mud weight was higher than on the other two wells. Density was raised to 13.5 lb/gal was to drill the 7 in. shoe and after encountering pressure density was raised to 14.5 lb/gal to stabilize the hole. The rig was evacuated for a hurricane and the open hole left exposed for three days and reentered without problems. Upon return to operations, the hole was circulated and logs and casing run without any problems.

Actual performance in the production intervals of the three wells is as follows.

A-7 (2671' – 4735' MD)

After displacing out of surface casing the

properties of the fluid were as follows:

- Fluid Density, lb/gal: 12.4
- PV, cP: 12-18
- API Filtrate, mL / 30 min: 5.8
- Maximum angle: 33°
2064 ft drilled in 35 hr,
Interval Average ROP: 59 ft/hr

A-8 (3738 – 6930' MD)

Displaced out with high performance fluid and maintained with premix. 3192 ft of hole was drilled. Rig evacuated twice for storms.

- Fluid Density, lb/gal: 11.9
- PV, cP: 12-17
- API Filtrate, mL / 30 min: 7.8
- Maximum angle: 72°
3192 ft drilled in 48 hr,
Interval Average ROP: 66 ft/hr

A-9 (6060 – 6844' MD)

Displaced out with high performance fluid and maintained same with premix. 9 5/8 in. shoe at 6060 ft drilled to TD of 6844 ft. Rig evacuated for hurricane after drilling out leaving open hole exposed for three days. No fill or drag/swabbing after conditioning trip. Logged and ran casing to bottom.

- Fluid Density, lb/gal: 11.9 - 14.5
- PV, cP: 21-26
- API Filtrate, mL / 30 min: 8.2
- Maximum angle: 40.78°
Interval Average ROP: 46 ft/hr

Premix Components

Typical make up of the premix was:

- 2-3% methyl glucoside based shale stability additive
- 1-2% complex ester based ROP enhancer
- 4 lb/bbl humalite drilling fluid conditioner
- ½ lb/bbl Pac
- Caustic soda as needed to maintain a pH of 10

Wellbore Trajectories

Although all three wells were directional (Table 3), the A-8 had the most difficult trajectory (Figures 4 & 5). A maximum angle of 72° Incl at 3581 ft MD was achieved before the hole was turned from 146 Azi to 180 Azi while dropping angle to 55° Incl at TD of 6930 ft MD. Two short trips were performed with out any difficulty and TD was reached without problems. A regimen of weighted, high viscosity/low viscosity sweeps were utilized for the entire length of the well. A combination of LCM products was added to the sweeps to prevent whole mud losses. No mud losses to the formation were observed at any time during the drilling of this well. The same procedures were used effectively in the A-7 and A-8 wells.

Conclusion

System performance exceeded pre-determined objectives for this series of wells. The wellbores exhibited excellent stability. The fluids were lubricious which enabled drilling these tortuous well paths without detrimental torque or drag. Days required for drilling to TD were significantly reduced (Figure 6 & 7). A strict regimen of short trips, high pump rates, heavy weight fluids and thick and thin sweeps kept the hole clean. Fill and drag were not experienced even in the most challenging sections of the wells.

Figure 8 displays the average daily progress made on previously drilled offsets and current project wells.

Careful analysis of the offset wells revealed areas where fluid system modifications were expected to yield beneficial results. The planned use of Newpark Drilling Fluid's proprietary products, LST-Md™ (MEG shale stabilizing agent with solubilized Soltex®) and NewEase® 203 (complex ester), provided the desired level of shale stabilization and lubricity which achieved a dramatic reduction of rotating days required to complete the drilling of these wells.

Nomenclature

°	=	Degrees
°F	=	Degrees Fahrenheit
AFE	=	Acknowledgement of expenditure
API	=	American Petroleum Institute
Azi	=	Azimuth
bbl	=	Barrel, 42 gallons
cP	=	Centipoise
ft	=	Feet
ft/hr	=	Feet per hour
hr	=	Hour
in.	=	Inch
Incl	=	Inclination

lb	=	Pound
lb/bbl	=	Pound per barrel
lb/gal	=	Pound per gallon
LCM	=	Lost circulation material
MD	=	Measured depth
MEG	=	Methyl glucoside
min	=	Minutes
mL	=	Milliliters
OBM	=	Oil-based mud
PL6-1	=	Pliocene series (formation)
PV	=	Plastic viscosity
ROP	=	Rate of penetration
TD	=	Total depth
TVD	=	True vertical depth

Note

Soltex is a registered trademark of Drilling Specialties Company LLC.

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Table 1: Lab report

Lubricity Testing of a Lab Formulated Water-Based Drilling Fluid

Scope of Project Formulate a basic water-based drilling fluid and add various lubricity agents to the fluid. Run lubricity tests on formulated fluids after hot-roll for 16 hours at 150°F.

Results

Results indicate the additions of Methyl Glucoside (MEG) shale stabilizing agent give the best results for lowering the coefficient of lubricity of the fluid. Results tabulated below.

Base Fluid – 10.5 lb/gal water-based fluid containing 10 lb/bbl bentonite, 0.5 lb/bbl zanthum gum, 1.75 lb/bbl caustic, 5 lb/bbl humalite, 1.5 lb/bbl Pac and 15 lb/bbl Rev Dust.

Base Fluid Properties after Hot-Roll:
Plastic Viscosity/Yield Point – 19 / 18
Gels – 5/8
API Fluid Loss – 5.1 mL

Fluid Formulation	Lubricity Coefficient
Base Fluid	0.288
Base plus 1% MEG shale stabilizing agent	0.273
Base plus 3% MEG shale stabilizing agent	0.278
Base plus 5% MEG shale stabilizing agent	0.237
Base plus 1% Complex Ester	0.262
Base plus 3% Complex Ester	0.231
Base plus 5% Complex Ester	0.214
Base plus 1% MEG shale stabilizing agent, 3% Complex Ester	0.248
Base plus 3% MEG shale stabilizing agent, 3% Complex Ester	0.236
Base plus 5% MEG shale stabilizing agent, 5% Complex Ester	0.232

Table 2: Mud densities maintained at or less than predicted

	A-7	A-8	A-9
	2671' - 4735' MD	3738' - 6923' MD	2867' - 6432' MD
Projected Mud Weights	10.5 - 12.5	10.5 - 13.0	10.0 - 13.5
Actual Mud weights	9.5 - 12.4	10.0 - 11.9	10.0 - 14.5

Table 3: Well geometry

	A-7	A-8	A-9
Total Depth	4735 ft MD	6923 ft MD	6844 ft MD
Actual Maximum Angles	33°	72°	40.78°

Figure 1

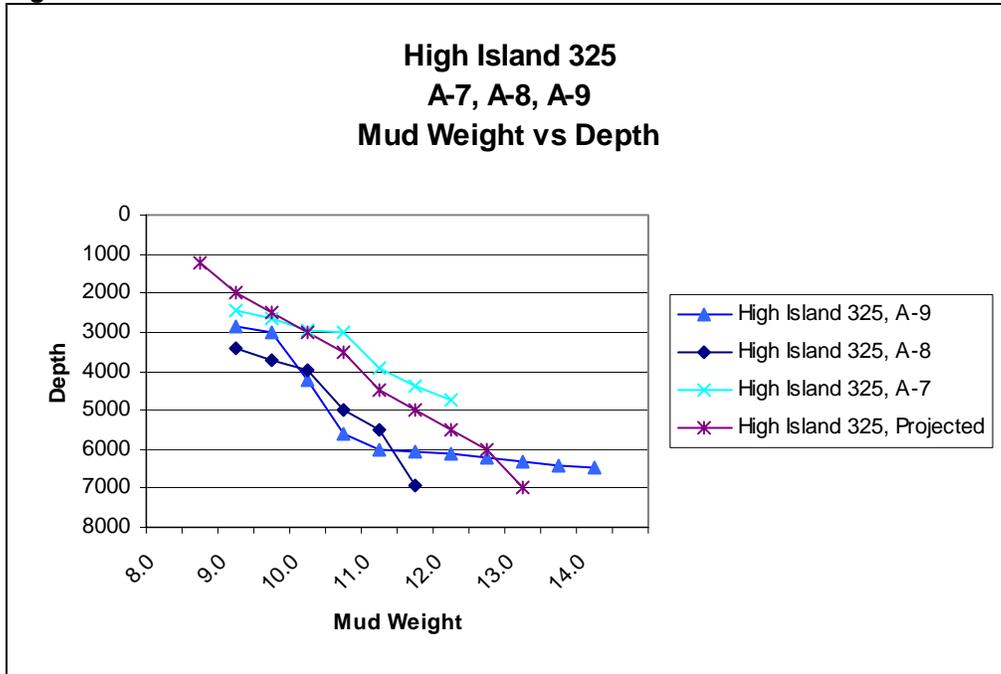


Figure 2

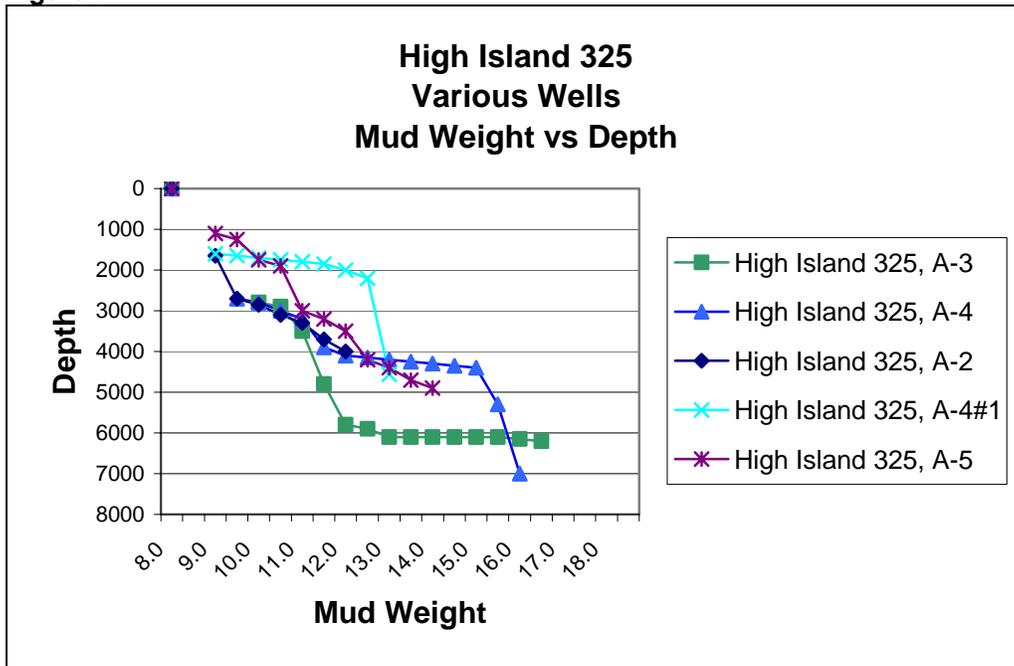


Figure 3

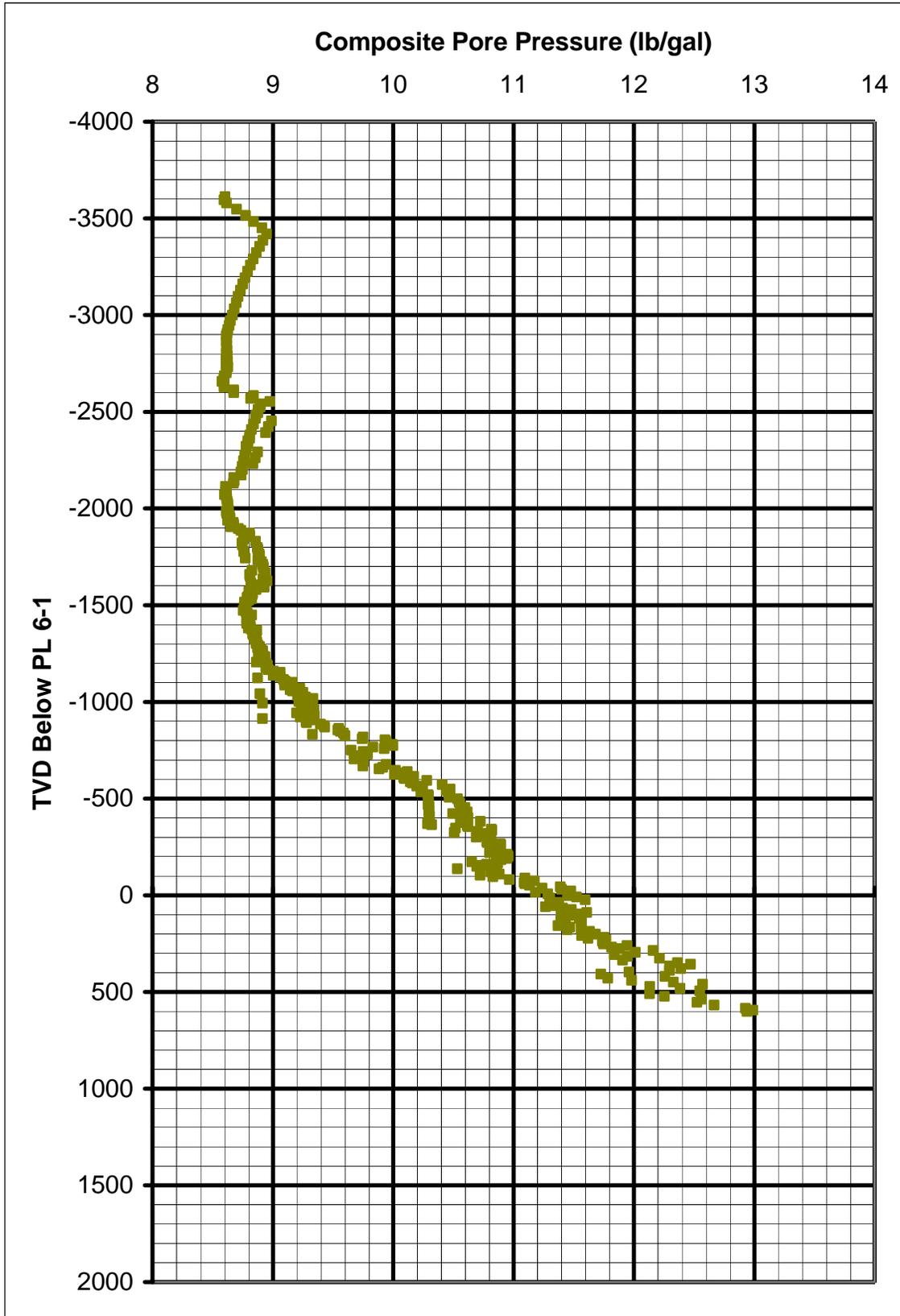


Figure 4: High Island A325 A-8, as seen from origin to TD
HUBS - Wellbore Trajectory
View Azi: 141; Horizontal: 17

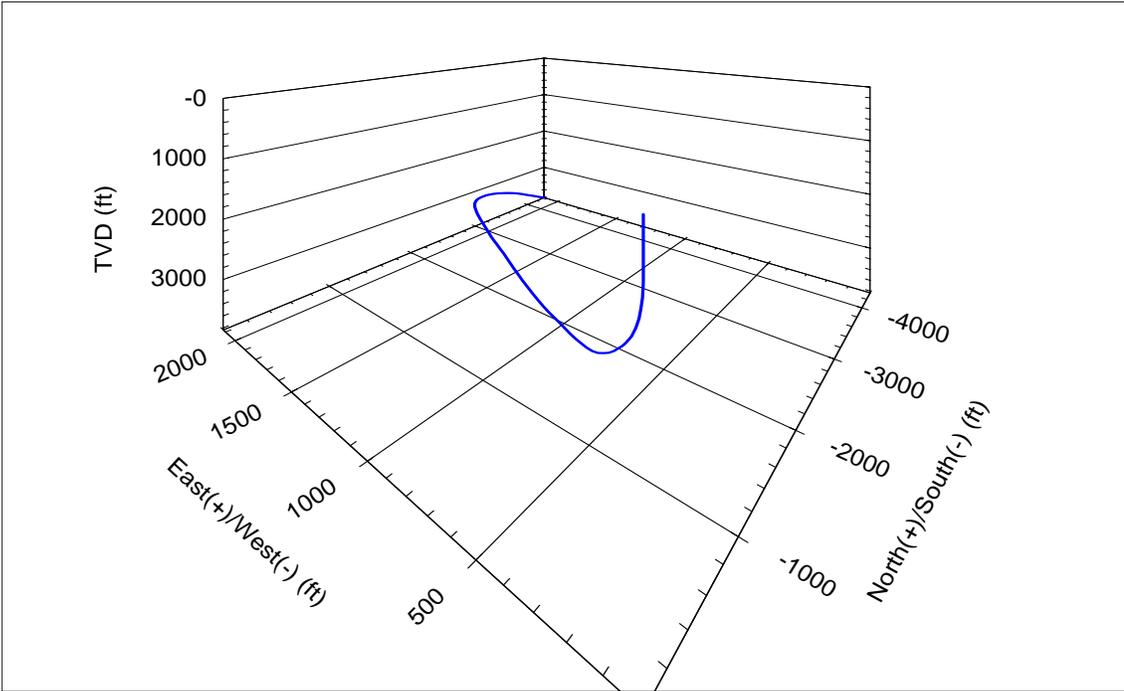


Figure 5: High Island A325 A-8, as seen from TD to origin
HUBS - Wellbore Trajectory
View Azi: 319; Horizontal: 0

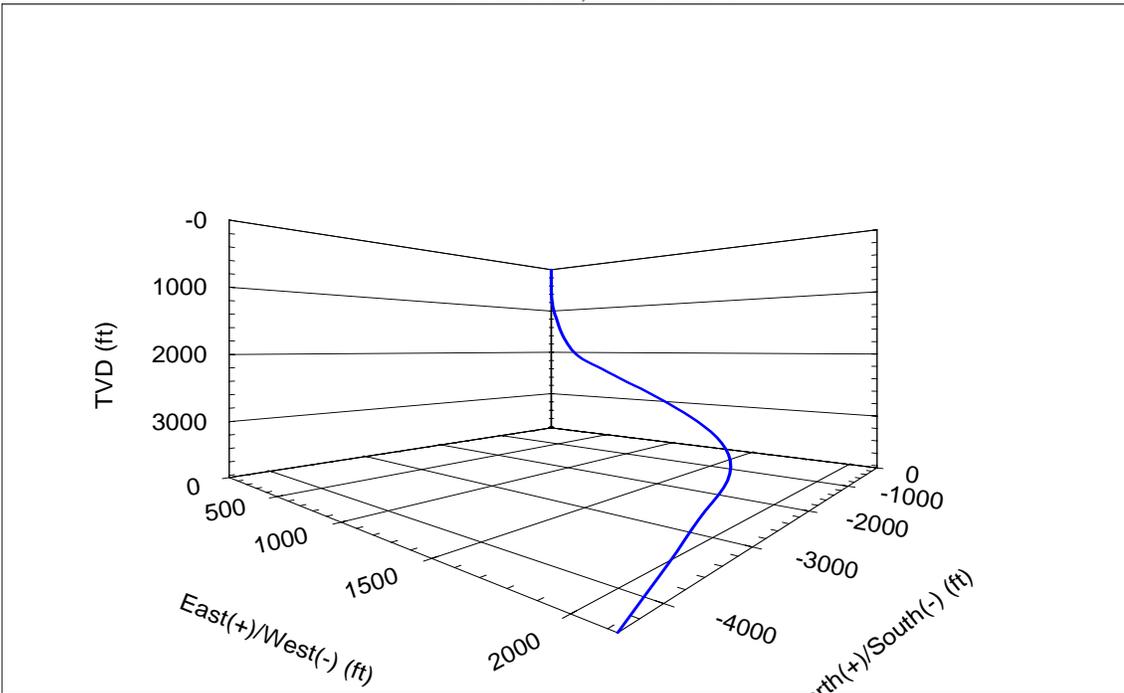


Figure 6

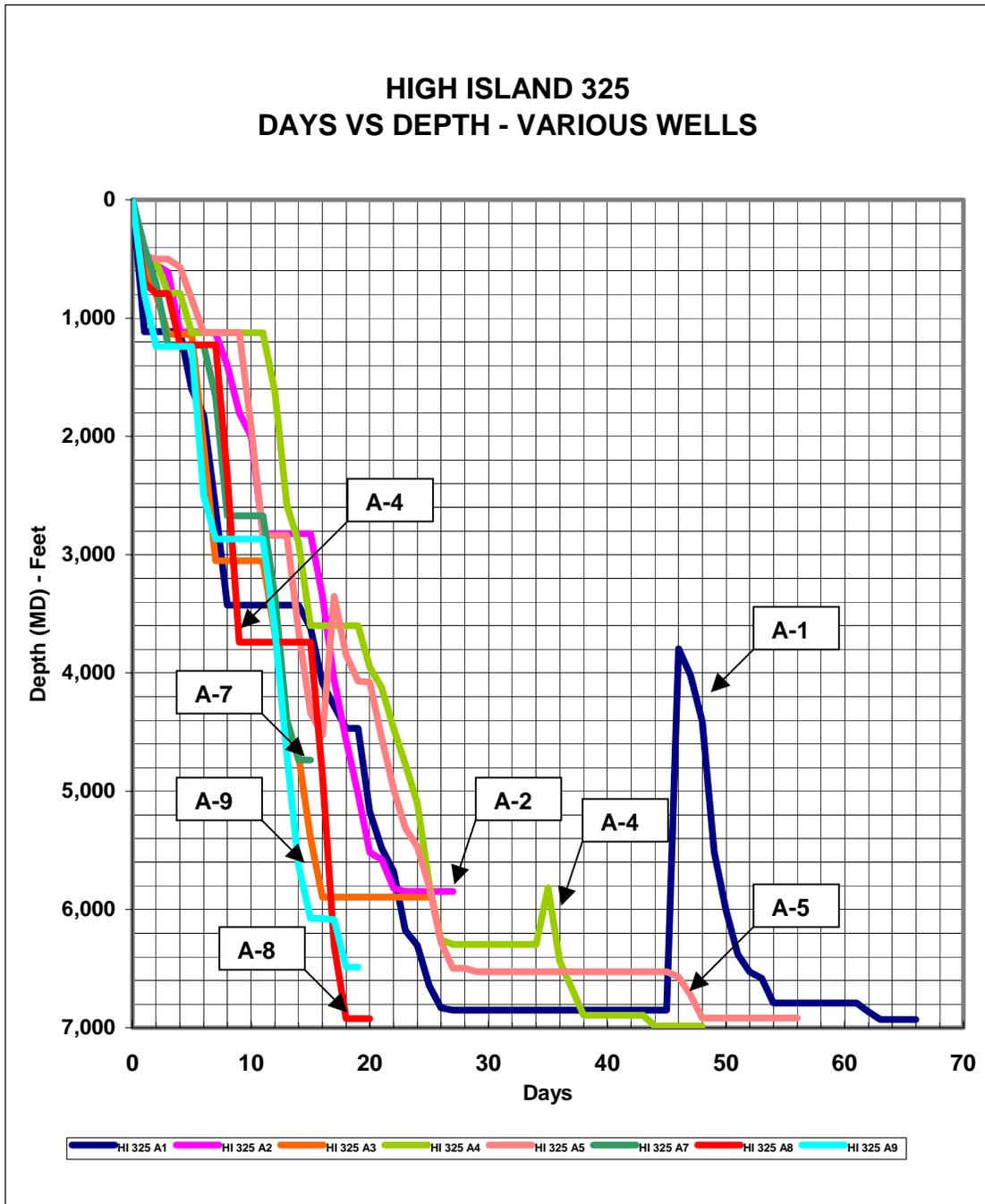


Figure 7

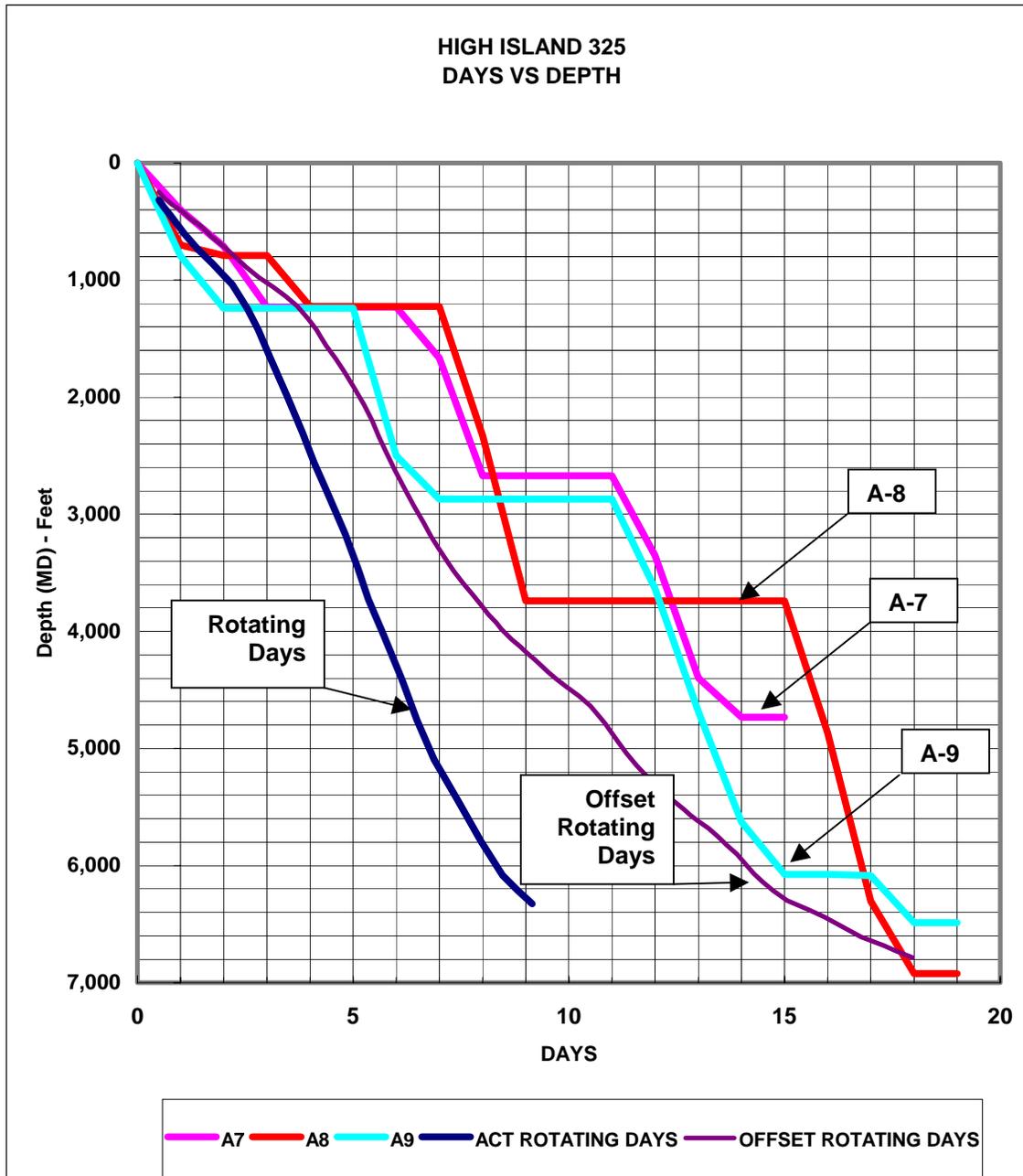


Figure 8

