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Planning and Field Validation of Annular Pressure Predictions

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Abstract

The correlation of predicted and measured annular pressures is a very complex process, and requires a thorough understanding of drilling fluids and annular pressure tool data. The engineer's knowledge of annular temperatures and pressures, and their effects on the rheological, thermal, and compressibility properties of synthetic-based drilling fluids, largely influence the accuracy of these predictions. Other important considerations include the monitoring and collection of rig-site information such as hole cleaning efficiency, torque and drag, temperature measurements, and tool pressure losses. The engineer must work in close communication with the pressure tool provider and surface logging, and relate tool data with specific events of the drilling operation.

This paper presents the results of an initiative to plan and execute the validation of a sophisticated hydraulics program while drilling in deepwater. The planning-phase centered on the data collection process, as well as the methodology used in deriving pressure predictions. The validation was based on comparison of these predictions to measured surface data and annular pressures.

Introduction

Deepwater operations are extremely expensive and emphasis is placed on controlling drilling costs by maximizing drilling rate and minimizing down time. Annular pressure management is critical to the success of most deepwater wells because of problems related to wellbore ballooning, inadequate hole cleaning, lost circulation, and shallow water flows. Downhole pressure tools are routinely used to monitor annular pressures as predictors and indicators of such problems.

With consideration given to rate-of-penetration, gas hydrate suppression, hole stability, ease of wire line logging, elimination of short trips, and the ability to utilize PDC bits, deepwater wells are typically drilled with synthetic-based muds (SBM). However, SBM is very sensitive to temperatures and pressures, and downhole conditions can cause significant fluctuation in both density and rheological properties of these drilling fluids. Computer software is available for use at the rig-site and is used in combination with annular pressure tools to predict, monitor, and manage annular pressures. Dynamic and steady state models complement real-time downhole pressure tool measurements and can be used to delineate the source of changes in annular pressure. The significant variations in annular temperatures encountered in deepwater make the task of consistently correlating predicted annular pressures with annular pressure tools a difficult task. The engineer must have a thorough knowledge of the drilling operation, drilling fluid characteristics, and pressure tool data.

Drilling Fluids

Relative to their near-shore counterparts, deepwater marine shales were compacted under low overburden pressures. These geologically younger shales typically have poor fracture integrity and low fracture gradients, are highly reactive and dispersive, and must be drilled with highly inhibitive mud systems. The combination of high hydrostatic pressure and low water temperature also promotes the potential for formation of gas hydrates in the conductor pipe and subsea blowout preventers. Mud systems have been formulated with salts, polyols, glycols, alcohols and sugars to thermodynamically suppress the formation of gas hydrate crystals.

Sodium chloride brine - partially hydrolyzed polyacrylimide (PHPA) polymer water-base muds were originally used to drill deepwater wells. High salt levels are used to suppress gas hydrate formation, and are combined with PHPA to minimize clay swelling and hydration. These systems were technically superior to earlier water-based muds, but were still deficient in their ability to reduce bit balling and promote increased rates of penetration. SBM meet or exceed the shale stability and gas hydrates suppression attributes of salt/PHPA systems and are excellent in maximizing rates of penetration. Although more expensive on a cost per barrel basis than water-based muds, synthetic-based drilling fluids have allowed operators to realize significant reductions in overall well costs. These savings are due to reductions in the number of bit trips, improved borehole stability, increased rates of penetration and, in some cases, the elimination of an additional casing string. Despite their considerable technical merits, synthetic-based drilling muds are not always trouble-free. The occurrence of lost circulation when using synthetic-based systems is a major concern for deepwater operators. Excessive losses of mud volume can temporarily shut down drilling operations and add a tremendous expense to overall well costs. It has been proven that hydraulics planning and well site monitoring can minimize circulating densities and drilling problems.

Temperature Effects

When initiating circulation after periods of static conditions, annular temperature profiles change dramatically as the large volume of mud, which had been in the riser, is incorporated into the circulating system. Another operation that has a major impact on the circulating temperature profile is the use of riser booster pumps. Cold surface mud pumped down to boost the riser will have an influence on the overall circulating temperature profile. In addition, the frequency and the flow rate at which the riser is boosted can make predicting the circulating temperature and pressure profiles even more challenging.

Temperature profiles can be calculated using geothermal gradients, or defined using surface and downhole measurements. Steady state models calculate temperature profiles after extended periods (steady state), such as when geothermal equilibrium has been reached, or annular temperatures have stabilized. Dynamic models simulate changes in downhole temperature and pressures as a function of time. A dynamic model should consider thermo-physical properties of the fluid and all well bore components the fluid will contact. In addition, the effects of friction generated heat need be considered. Time dependency is an important consideration because significant fluctuations in annular temperatures and pressures occur on the first circulation after a trip and as the mud in the riser has cooled.[1,2] This dynamic temperature model has proven to be very accurate in simulating downhole temperatures.[3] Figures 1 through 2B show how circulating temperature profiles can vary with well bore configuration. All three cases have the same formation geothermal gradient. Figure 1 is a profile of a land well with no water cooling effects. Figure 2A illustrates the water cooling effect while drilling in 5000 ft. of water. Figure 2B is the same well as 2A with a continuous boosting of the riser. When comparing these figures, the impact on the circulating temperature profile can be quite significant between land wells and deepwater wells. In addition, the use of booster pumps will have an impact on the overall circulating profiles of deepwater wells.

Hydraulics Models

The accuracy of hydraulics modeling is greatly dependent of the accurate quantification of downhole temperatures and pressures. Temperature models fall into two categories, either steady state or dynamic. The effects of the cold temperatures encountered in the water column of deepwater wells presents a technical hurdle in terms of modeling annular temperatures. These wells exhibit a negative thermal gradient from the surface location to the mud-line. The gradient then becomes positive as the formation temperatures increase with depth (Figures 2A-2B).

The hydraulics model used in this project is part of the ADVANTAGE System; Baker Hughes' integrated platform for all well planning, reporting, and analysis. This is a modular platform, which allows for customized features depending on services provided. Baker Hughes' services can share data at the well site within a common integrated multi-well relational database. Analyses can be run for hydraulics, hole cleaning, bit optimization, and swab & surge with common data set either for pre-well planning purposes, or daily operational data. The program divides the well into segments or grids, the length of which is adjusted with changes in the drilling assembly, well bore or survey. Downhole properties, such as HT-HP rheological data and density are calculated within each grid and updated into subsequent grids. These local fluid properties are then used to perform pressure drop, hole cleaning, and ECD analysis.

Both rheological properties and base fluid density change under conditions of temperature and pressure. The change of these two variables must be measured under temperature and pressure (HT-HP) conditions which the fluid will be subjected. The interpolation of rheological properties is performed individually for each dial reading. A bi-cubic spline method is used if a square matrix of HT-HP data is available. In the case there are fewer readings available, the data can be fitted to predefined equations to show the dial readings surface-fit as a function of pressure and temperature. The input data must cover the whole of the 2D space defined by the range of pressure and temperature to avoid partial extrapolation. The accuracy of the surface-fit is determined and the best-fit equation is used for the analysis (Figure 3). The goodness of fit is determined based on the standard deviation.

To correct for density, a compositional density model calculates local density under downhole conditions. The model corrects the whole fluid density based on the percent by volume of each component in the fluid. Equations have been derived for commonly used base fluids from pressure-volume-temperature (PVT) data, and are available in the hydraulics program.

Planning Considerations

Since SBM rheological properties and density are effected by temperature, one of the most fundamental parameters is a reference temperature. The density of SBM can vary up to 0.6 lbm/gal with a 40 to 50°F temperature change at ambient pressure. It is extremely important to have an accurate reference temperature when modeling highly expandable/compressible SBM for ECD/ESD. A temperature reference to mud weight should be closely monitored, especially after extended periods of static well conditions. Density variations perceived to arise from barite sag might in fact be the result of temperature changes on mud density. The density correction performed by the compositional model is dependent on percentages of each component in the fluid. An inaccurate solids and chemical analysis can also contribute to poor ECD/ESD predictions.

The effect of temperature and pressure on the density and rheology of invert-emulsion drilling fluids is well known. Actual annular temperatures and pressures are unknown in pre-well planning; however, annular pressure predictions are dependent on the relevant HT-HP rheological and PVT data. Greatest accuracy is achieved when the predicted ranges of downhole temperatures and pressures closely match actual values. The ability to accurately predict annular pressure losses, equivalent circulating and static density (ECD & ESD), is highly dependent on the circulating temperature profile, which can be calculated from geothermal gradients or defined from surface and downhole measurements. The temperature profile can also be defined at multiple points in the annulus using the dynamic temperature model. In Case History #1 the dynamic temperature model is used to simulate annular temperatures at multiple points in the annulus.

In addition to temperature effects on SBM, downhole pressures will impact the local density and rheology of the fluid. From expected survey data and anticipated fluid density, the hydrostatic pressure can be calculated. An approximation of the annular circulating pressure can then be calculated by adding an induced annular pressure to the hydrostatic pressure. This pressure estimation, repeated at various depths, can be used for developing test pressures in the HT-HP rheology test matrix. Accurate annular pressure predictions can be made only after adjusting for the temperature and pressure dependency of compressible, invert-emulsion drilling fluids. Figures 4-5 show the dependency of density with pressure and temperature on a typical SBM base fluid. All synthetic base fluids will have a similar trend in regards to compressibility/expandability, however, the degree to which density varies will be dependent on molecular size and structure of the base fluid. Knowledge of base fluid type and PVT dependency is crucial when predicting local density for overall ECD and ESD predictions.

Another important aspect in planning phase is monitoring operational parameters while drilling, and recognizing how they can influence the accuracy and relevance of pressure predictions. Hole cleaning efficiency can be inferred by observing indicators such as torque and drag, the effects of sweeps, cuttings integrity, and cuttings size and density. Improper hole cleaning can be detected by the variations in the predicted ECD compared to actual downhole pressures. The hydraulics model and pressure tool used together can help mitigate problems before they occur. Deviations from expected trends can be used as indicators of potential downhole problems.[1] Inefficient hole cleaning can be detected as abnormal annular pressure increases measured by downhole tools.

Case History #1

This exploratory well was drilled in Mississippi Canyon, offshore Louisiana, in a water depth of 7,416 ft from the Deepwater Pathfinder Drill-Ship (Figure 6). The well was drilled to a total depth of 21,778 feet. The pressure tool used in this well was a Drill Collar Pressure (DCP) tool provided by Baker Hughes INTEQ. The DCP tool can measure both bore and annular pressure. Advanced electronics are used to provide tool accuracy with 0.25% of full-scale, up to pressures of 20,000 psi. The resolution of accuracy of this tool is 5 psi. Annular pressure data is used to calculate real-time Equivalent Circulating Density and Equivalent Static Density (ECD, ESD), and is displayed at the surface. With the bore pressure and annular pressure known, the overall pressure loss of the bottom-hole assembly below the DCP can be calculated, consequently allowing the hydraulics program to more accurately predict standpipe pressure (SPP). The DCP tool also delivers flow-off pressure measurements, which are invaluable in order to have an ESD and as a result have a good estimate of the HTHP effects. In addition, flow-off pressure measurements can quantify ECD’s during tripping operations.

A dedicated engineer was on location to perform hydraulics calculations and to collect information while drilling the SBM intervals. The wellbore integrity and gauge hole provided by the SBM, combined with a lack of noticeable hole cleaning problems, minimized the effects of wash out and cutting beds on pressure predictions. Good correlation between flow line and tool temperatures was observed when using the dynamic temperature model. This information was used in designing a HT-HP rheological test matrix to characterize properties under downhole conditions. Figure 7 shows the predicted vs. actual stand pipe pressure (SPP) and ECD's calculated over 1000 ft. of the 12 ¼" section. Typically, calculated ECD's were within 0.1 lbm/gal of the tool ECD. Particularly noteworthy is the close correlation between calculated and observed SPP. The average deviation between calculated and measured SPP was 1.74 percent, ranging from 6.14 to 0.05 percent. The close correlation is attributed, in part, to known pressure loss from the tools, which was measured on the drill ship using the actual SBM. An example report of essential steady-state hydraulics analysis parameters is shown in Figure 8.

Downhole tool data, surface data and calculated measurements were plotted every 30 minutes to study trends. As data was collected, drilling was closely monitored, taking drilling activities into account during the information evaluation process. Data were plotted for all activities such as tripping, drilling, pipe change, and lapse time. Meaningful comparisons in this paper are presented for data with steady drilling of approximately 1000 feet. The high circulation rates capable with this drill ship resulted in no evident hole cleaning problems. Drilling fluid sweeps in the 12 ¼"section did not result in increased accumulation of cuttings at the shakers, indicating the hole was generally clean.

Case History #2

This well was also drilled in Mississippi Canyon at a water depth of approximately 4,900 feet, and was a Gulf of Mexico record well in terms of total measured depth (MD). Final TD of the well was 29,750' MD (29,680' Total Vertical Depth). The pressure tool used in this well was a DCP tool provided by Baker Hughes INTEQ. Five of the eight hole sections were drilled in one pass as planned. All geological requirements, including minimum acceptable depth of 28,100', ability to drill to 30,000' and logging the well at TD were achieved. No major hole problems or stuck pipe problems occurred. One kick was handled from ~27,000', which may be the deepest well control circulation the operator has ever performed.

Figure 9 shows results from the predicted and actual SPP and ECD over 1000 feet of the 12-¼" interval. Field temperature data (surface and bottom-hole) was used to characterize the circulating annular temperature profile. Calculated ECD values were 0.23 to 1.39 percent of actual, with an average deviation of 0.91 percent. Average predicted SPP values were within 4.71 percent of actual values.

Case History #3

Unlike the previous examples, this was an extended reach deepwater well. The 12 ¼" section was kicked off at approximately 3,900 ft and built to 75° angle. Angle was maintained at 75° for approximately 12,800 ft, then built to 89° and finally dropped to 60° to the target. Close tolerance on fracture gradient and pore pressure posed a potentially high chance of lost circulation. This well was drilled to TD in a single, record setting bit run, and eliminated a potential 8 ½" section.

The pressure tool used in this well was a Modular Advanced Pressure (MAP) tool provided by Baker Hughes INTEQ. Advanced electronics are used to provide tool accuracy with 0.25% of full-scale, up to pressures of 20,000 psi. The resolution of accuracy of this tool is 5 psi. Tool data was used to compare predicted and measured results. The circulating annular temperature profile was defined using tool data. Figure 10 compares predicted and actual SPP and ECD's. It can be seen that the correlation between predicted and actual ECD values is poor. The average deviation for ECD is 2.21 percent, with some values as high as 3.37 percent. The MAP tool can measure both bore pressure and annular pressure, therefore allowing for extracting the tool pressure losses. The average calculated SPP was within 3.85 percent of actual SPP. Knowing the tool pressure loss along with the theoretical bit pressure loss, assist in more accurate SPP calculations.

Based on rig site observations and documentation, the operation encountered hole-cleaning problems. This posed a challenge for hydraulics modeling in that the buildup of cutting beds changed the geometrical configuration of the well bore. To model the geometrical changes, the model determines the problematic section and calculates a cutting bed height. Figure 11 shows the theoretical bed height and corresponding percentage change in total flow area. Based on ROP and flow rates, the model calculates a new theoretical diameter arising from cuttings bed deposition. In some sections the total flow area was reduced by as much as 23 percent, corresponding to cutting concentrations as high as 16 percent by volume. Typically, cutting concentrations of 5 to 6 percent by volume indicate poor hole cleaning. Steady state modeling assumes that rate-of-penetration (ROP) is constant, when in reality it is not. Therefore, the calculated cuttings bed deposition is a worst case scenario. ECD's were closely monitored in the actual operation and remedial measures were taken to correct hole cleaning problems throughout the section.

Figure 12 illustrates the effects of cuttings bed removal on calculated and measured ECD's when drilling 9000' of the 121/4" interval. The average percentage difference in ECD was reduced from 2.15 to 0.86 percent with efficient hole cleaning.

Conclusions

- Accurate and consistent correlation of predicted to actual annular pressures is not a trivial undertaking. The temperature and pressure effects encountered in deepwater wells, and their effects on the rheology and density of SBM's must be considered.
- Accurate, complete rig-site observations is crucial in assisting accurate ECD predictions
- Reference temperature to mud weight, and accurate compositonal make-up of the mud, is critical for accurate annualar pressure predictions
- Predicted annular pressures are highly influenced by the circulating annular temperature profile.
- Abnormally high ECD calculations can assist in identifying potential real time hole cleaning problems

Acknowledgments

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3.

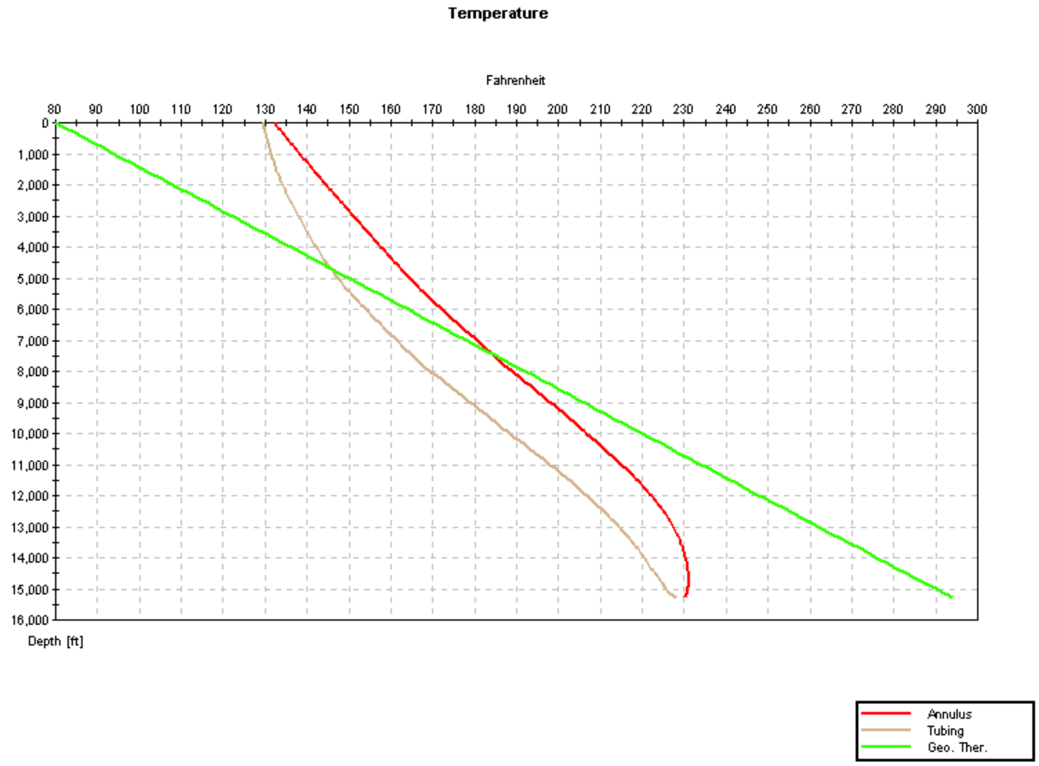

Figure 1. Dynamic temperature profile of land well

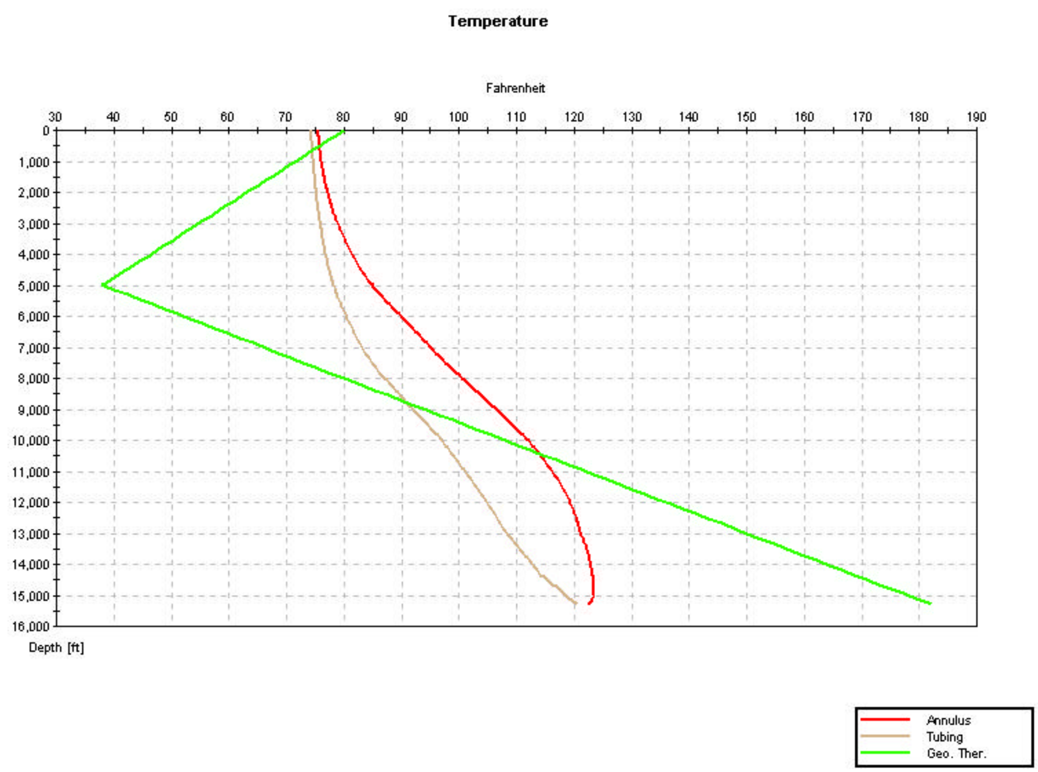

Figure 2A. Dynamic temperature profile of deepwater well

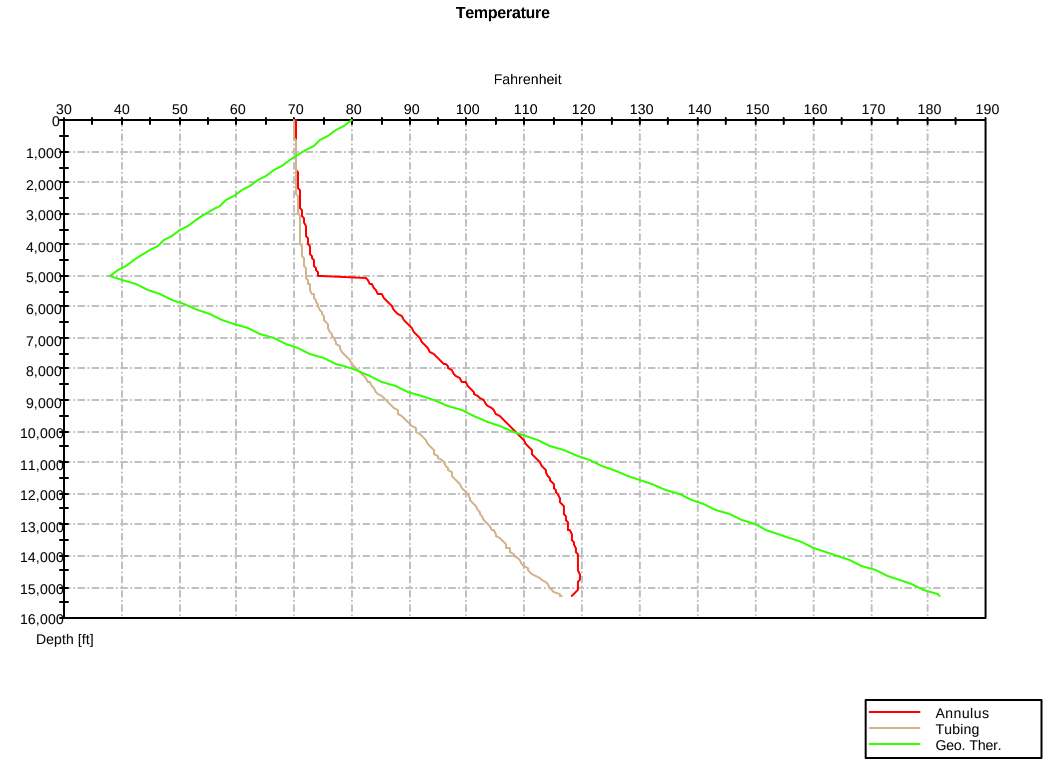

Figure 2B. Dynamic temperature profile of deepwater well with booster pump

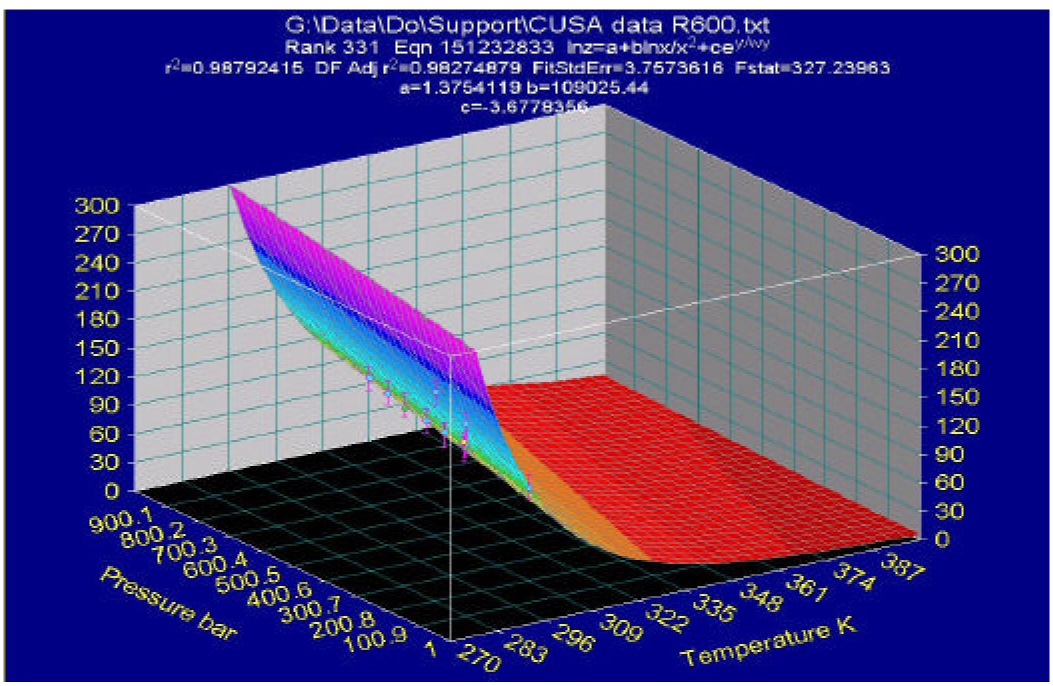

Fig. 3- 3-Dimensional curve Fit of HT-HP rheological data.

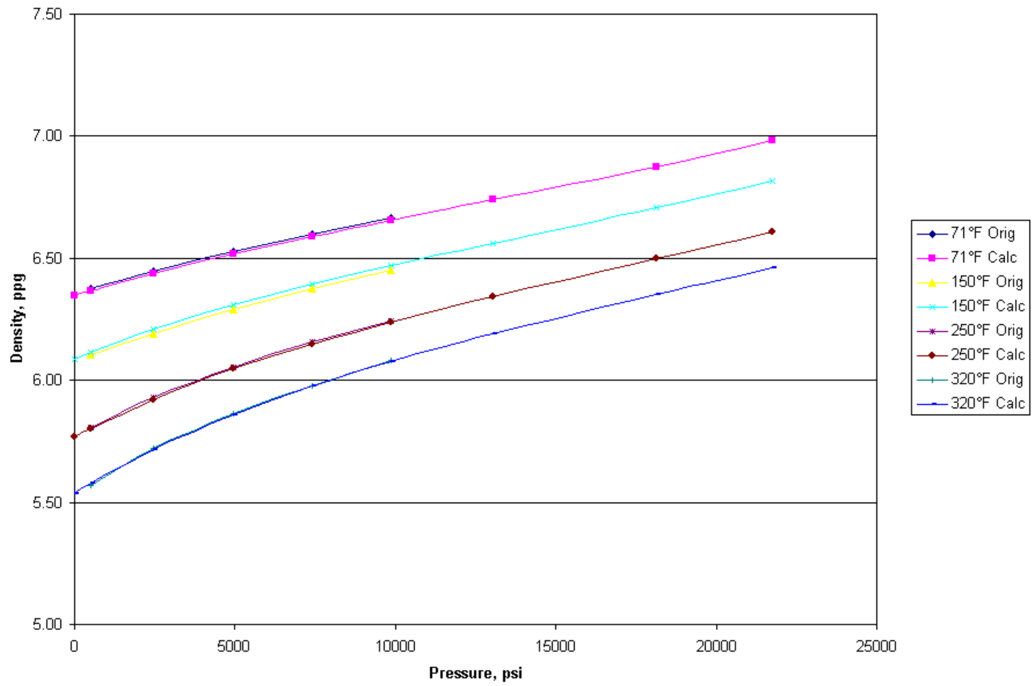

Figure 4. PVT on synthetic base fluid (Isotherm)

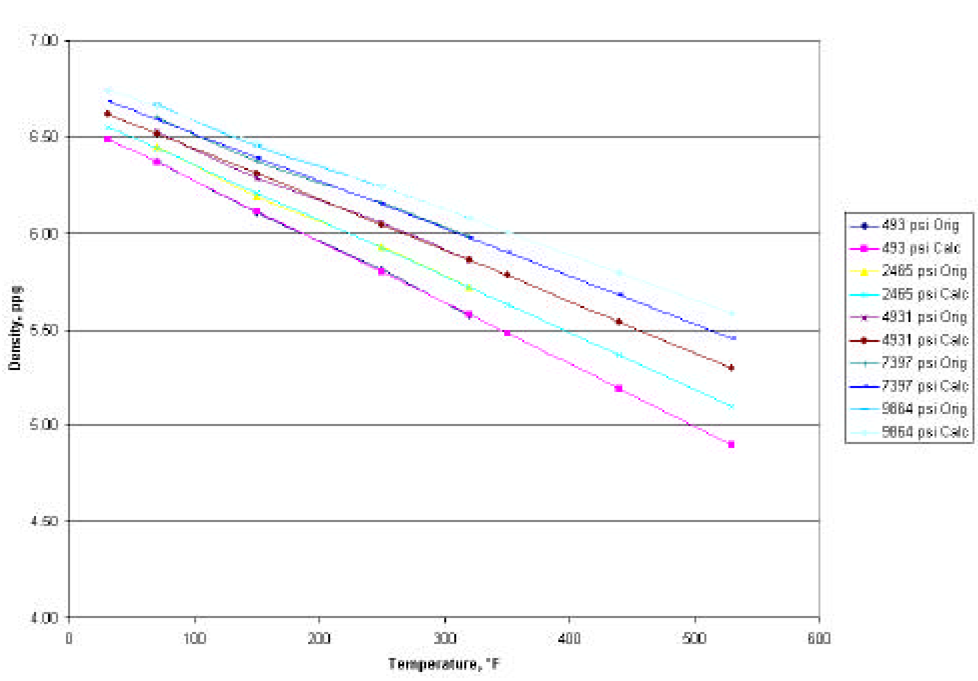

Figure 5. PVT on synthetic base fluid (Isobar)

Fig. 6- Deepwater Pathfinder Drill Ship.

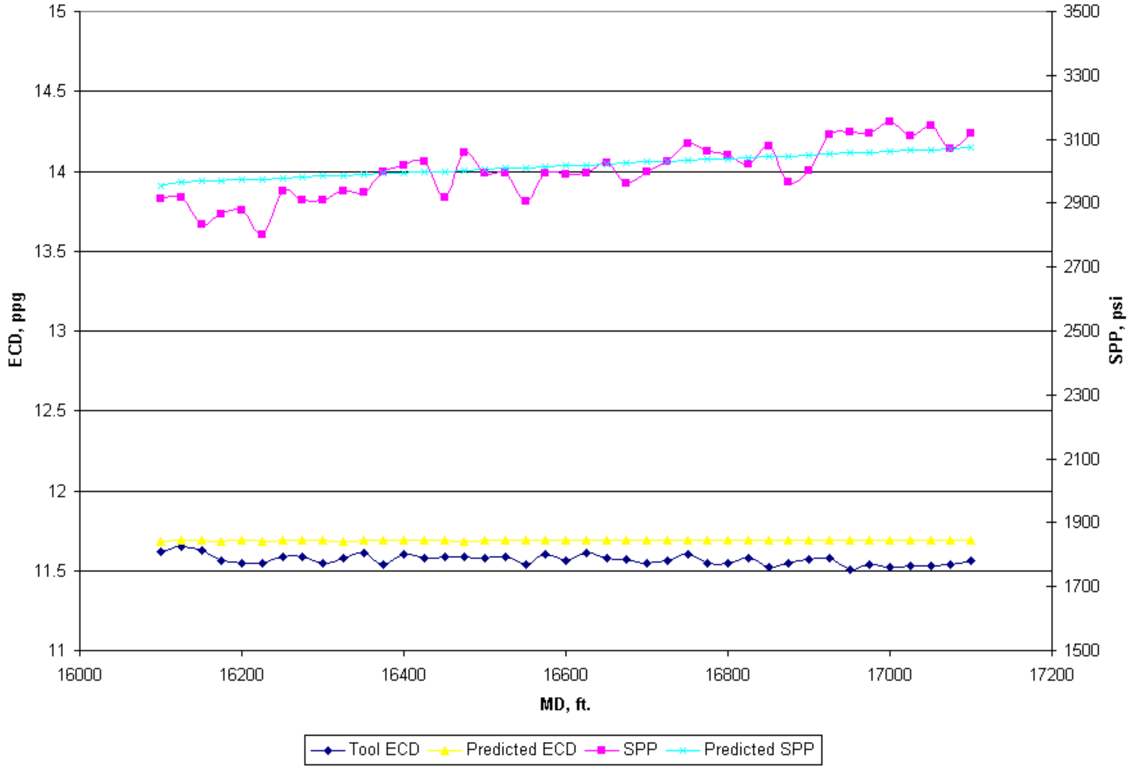

Figure 7. Predicted vs Measured Pressures in 12 ¼" Section – Case History #1

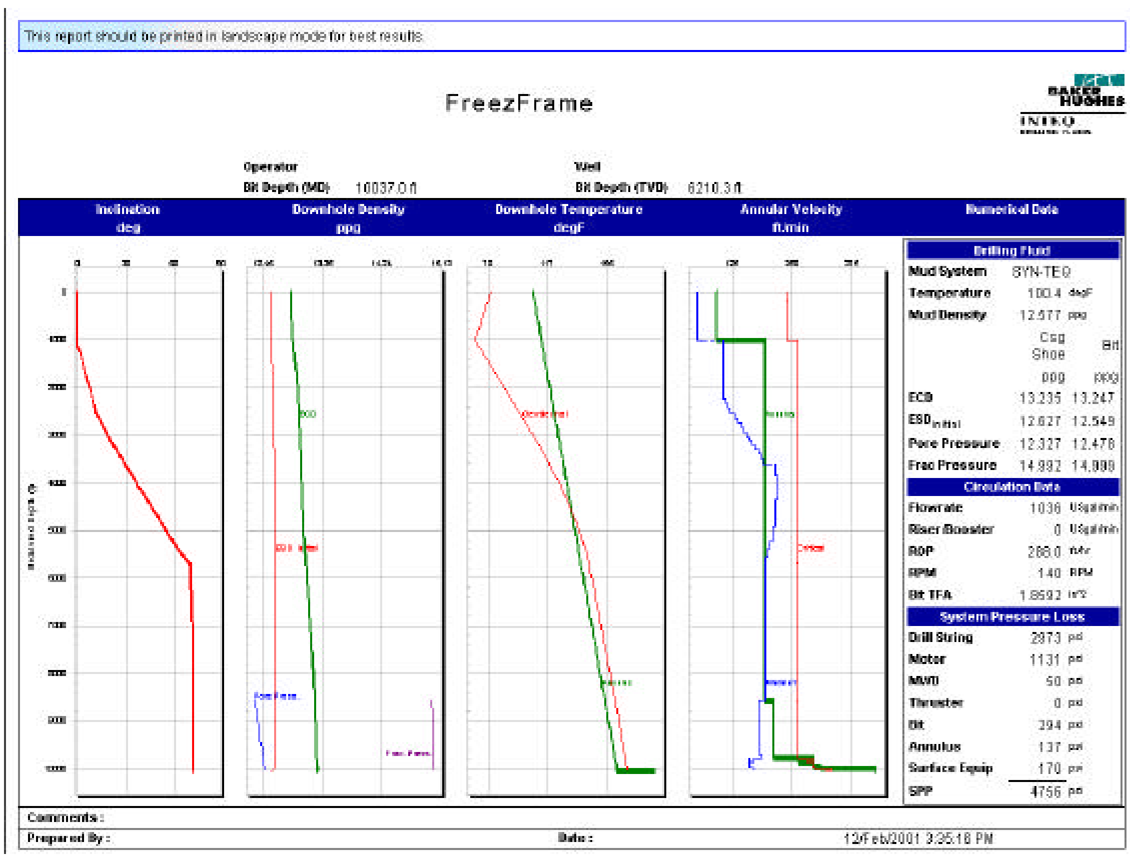

Figure 8. Comprehensive Hydraulics Report

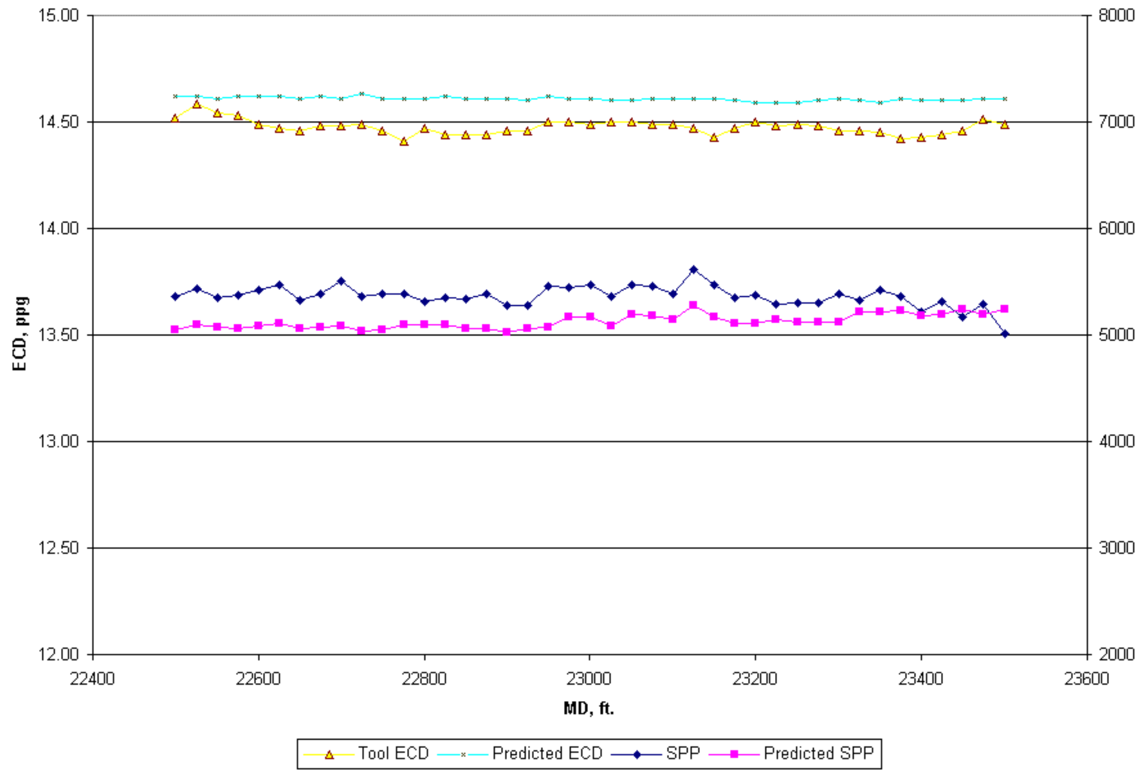

Figure 9. Predicted vs Actual Pressures in 11.4" Section – Case History #2

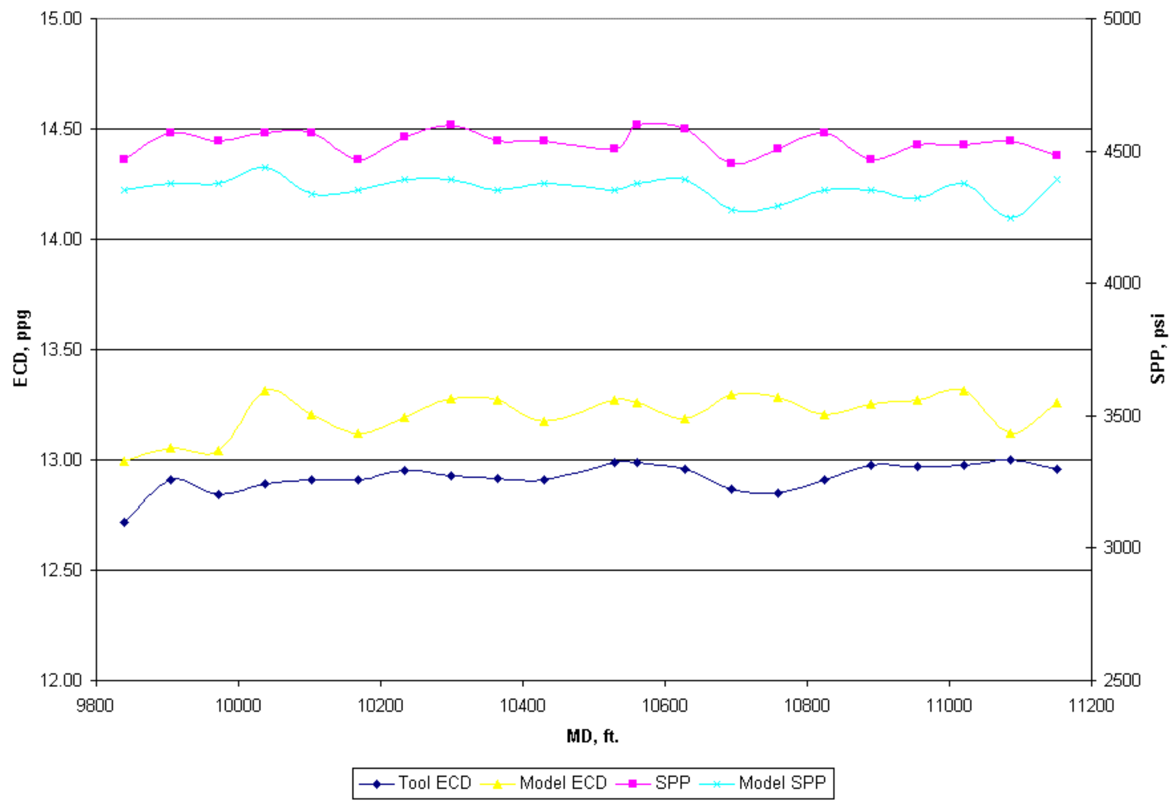

Figure 10. Predicted vs. Actual Pressures in 12 ¼" Section- Case History #3 – poor hole cleaning.

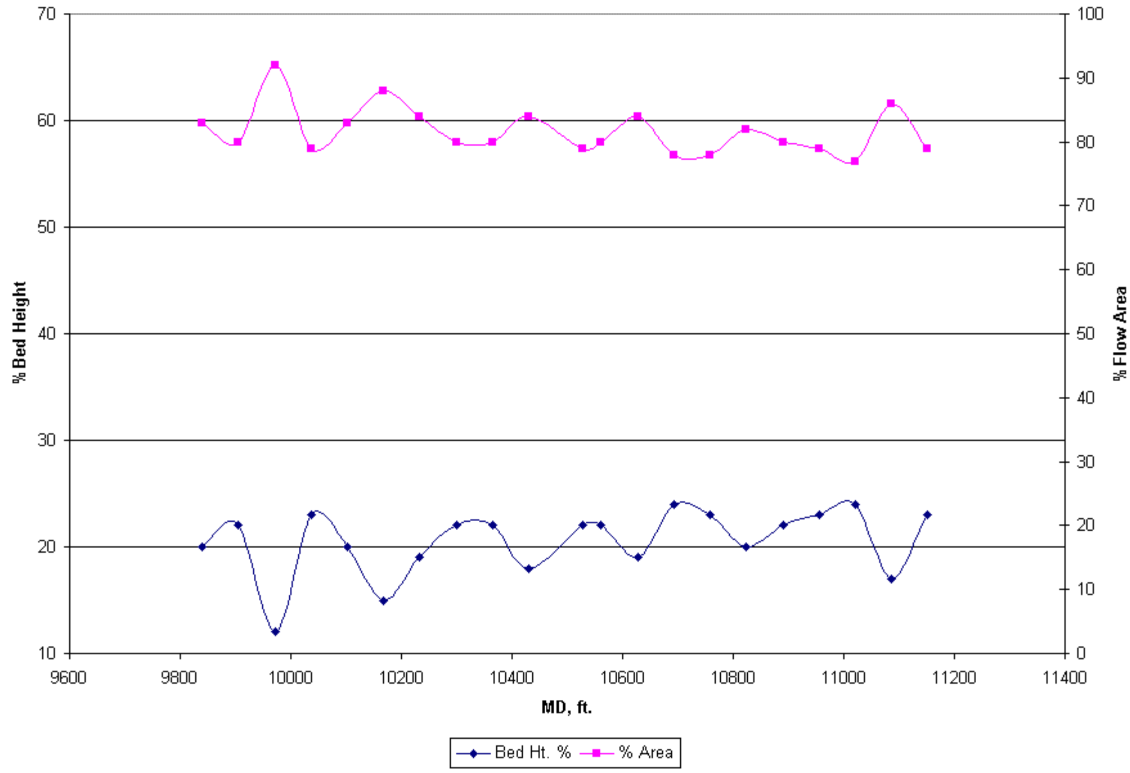

Figure 11. Theoretical Bed Height/Annular Flow Area Reduction

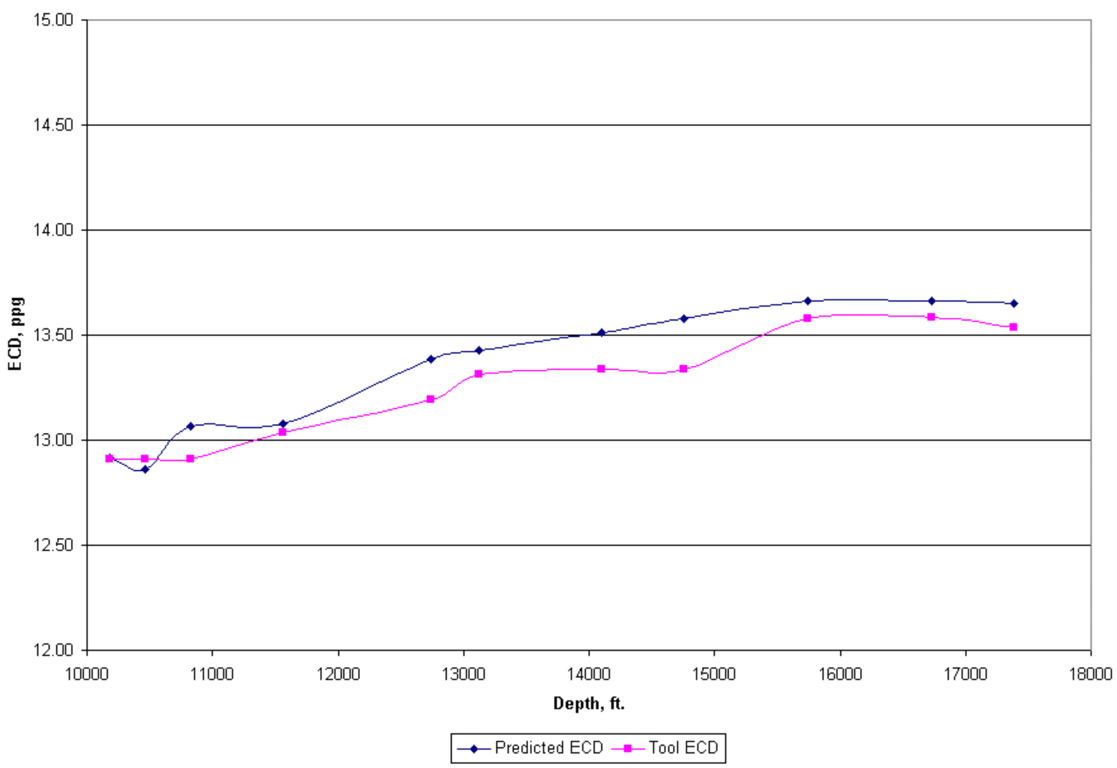

Figure 12. ECD's Without Theoretical Cuttings Bed