



Case History: Hydraulics Modeling Software Helps Optimize Drilling and ECD Control with High Degree of Accuracy on Deep, Hot Gulf of Mexico Shelf Well

Steven L. Stegeman, Dominion E&P, Inc.; Brian Coles and Wayne Rogers, Baroid product service line, Halliburton

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Abstract

A number of hydraulics modeling programs have been developed to help optimize drilling fluid performance. The Gulf of Mexico (GOM) case history presented in this paper reflects the high degree of accuracy that can be achieved with proprietary software designed specifically to produce verifiable predictive models for all types of drilling fluids under well-specific conditions, including compressibility, temperature effects, and sweep impact. The ability to account for temperature effects was critical because the anticipated bottomhole temperature (BHT) was 350°F at the proposed total vertical depth (TVD) of 16,000 ft.

The program was used during the drill-well-on-paper (DWOP) stage and while drilling to model equivalent circulating densities (ECD), hole-cleaning efficiency, surge and swab pressures, and pressure loss. Comparisons to data from pressure-while-drilling (PWD) tools and observed results at the wellsite indicate that the hydraulics modeling software package provided consistently accurate predictive modeling throughout well planning and during well construction operations. For example, correlations between actual PWD and predicted values indicated that the average difference between measured PWD and predicted ECD was 0.029 lb/gal.

The operator was able to drill three hole sections in 18 drilling days and 258 rotating hours. The actual total mud cost was 17% below the planned cost.

As proven in field applications worldwide and demonstrated in the case history, the modeling program can produce an extremely reliable vision of drilling fluid and wellbore behavior based on the conditions specified by the user. The modeling software accounts for factors that influence ECD, including the following factors:

- Well geometry, tool joint effects, eccentricity
- Rotary speed
- Drilling fluid properties and downhole rheology
- Bit nozzle selection
- Pump output
- Fluid compressibility and thermal expansion
- Cuttings loading
- Rotary drilling and sliding intervals

- Cuttings size and slip velocity
- Rate of penetration (ROP)—sliding/rotating
- Fluid properties of sweeps
- Static and circulating wellbore temperature profile

Introduction

A lower than desirable ROP and multiple hole problems prompted the operator to change from a water-based fluid (WBF) to a synthetic-based fluid (SBF) at the 13 ⁵/₈-in. casing point on the OCS-G 22510 No. 2 well in West Cameron Block 100. The No. 1 well had been drilled entirely with WBF system because of the operator's previous experience with diesel-based mud losses. However, drilling fluid charges on the No. 1 well were more than twice the projected cost, and actual days to reach total depth (TD) were significantly higher than planned days.

The same issues were foreseen on the No. 2 well, eliminating any cost benefits that might have accrued from using the WBF system. The rig was not equipped for the zero-discharge cuttings disposal process required with diesel-based fluid. Drilled cuttings would be discharged overboard as they had been with the WBF system. The decision was made to drill the two final intervals with an environmentally compliant, clay-free SBF system.

The clay-free SBF system had been widely used in the GOM and had an established track record for reducing the whole mud losses typically associated with conventional SBFs. However, at the time the No. 2 well was drilled, the system had not been used to drill at the density and temperature parameters expected. The mud weight at TD could exceed 17.0 lb/gal, and the BHT could reach 350°F. Before this operation, the SBF system had been run at 17.0 lb/gal in a 325°F well and had been successfully tested in the laboratory at 350°F. The proposed No. 2 well would provide a challenging field trial.

Drill Well on Paper (DWOP)

The operator's decision to change out drilling fluid systems took place approximately 30 days before the spud date, accelerating the events that would normally

comprise well planning for a deviated, high-pressure, high-temperature (HPHT) well. Using a highly accurate hydraulics modeling software package, drilling fluids personnel analyzed the well plan, potential density and temperature effects, hole-cleaning efficiencies in the 39° angle wellbore, and numerous “what-if” cases to help ensure the best outcomes could be achieved.

The New Orleans-based drilling fluids laboratory performed extensive testing on the SBF system prepared for the well. The SBF base fluids intended for use on the No. 2 well were isolated at the shore-based mud mixing plant in Cameron, Louisiana. Mud volumes were mixed in 1.0-lb/gal increments based on the densities expected while drilling. Each batch was tested with the Fann® 75 HPHT viscometer over a wide range of temperatures.

Testing of invert emulsion fluids over the anticipated temperature and density spectrum is of prime importance. The expansion of the base fluid under increased temperature leads to a decrease in volumetric density not seen at the surface when the fluid is cooler. The increased temperature also causes a decrease in viscosity of the fluid. Conversely, increased pressure causes a compression of the base fluid, which yields a corresponding increase in volumetric density not seen under surface conditions.

These changes in the fluid create a downhole environment significantly different than surface conditions. Testing with the Fann 75 viscometer allows the modeling software to accurately predict rheology and density under the actual drilling conditions; therefore, changes in slip velocity, cuttings transport, and circulating pressures can be accurately modeled.

The rheological properties obtained with the Fann 75 viscometer were used by technical support and field personnel to model the hydraulics during the planning phase of the No. 2 well. Based on the operator’s well design, the rotation speed limit for each drilling assembly, pump output, and the fluid properties at various densities and temperatures, the modeling software calculated hole-cleaning efficiency and ECD at any point in the well. The parameters could be tested with a range of ROPs to help ensure that the maximum safe drilling rates could be sustained (**Fig. 1**). Modeling results were validated by PWD data and shown to be accurate within 0.03 lb/gal.

The program also accurately predicted surge pressures while running casing, allowing the operator to maintain an optimized balance between running speed and loss prevention, a key factor in controlling drilling fluid costs.

Of particular importance was the prevention of barite sag at the proposed mud weights. The SBF system had been used on more than 60 deepwater and shelf wells at the time with zero incidences of sag, but the drilling fluids specialists wanted to subject 17.0-lb/gal fluid samples to long-term sag testing. If the fluid showed any

tendency to sag, the formulation could be adjusted accordingly while the rheological properties necessary to minimize downhole mud losses were preserved. No sag occurred with the mud samples tested in the lab.

Drilling Challenges

The challenges that occurred over each interval are discussed in the following sections.

The 12 ¼-in. Interval

After setting 13 5/8-in. casing at 11,444 ft measured depth (MD), the operator drilled out with WBF and obtained a 16.6-lb/gal equivalent mud weight (EMW) by leakoff test, but only after a cement squeeze. The WBF was displaced with a 14.7-lb/gal SBF system. The 17° angle was built to 39° at a rate of 2° per 100 ft.

To minimize seepage loss, the SBF was pretreated with sized calcium carbonate. A known loss zone was expected at 12,800 ft MD and was actually encountered at 12,858 ft MD. The hole stayed full while static, but the loss rate while circulating at 570 gal/min was approximately 40 bbl/min. A 40-bbl pill formulated with a mix of sized calcium carbonate, deformable carbon-based material, fibrous material, and walnut hulls was spotted on bottom. The mud weight was reduced from 15.9 lb/gal to 15.7 lb/gal. Drilling resumed with no further problems. The total loss during this incident was 266 bbl, which was a relatively small volume compared to losses that had occurred on offsets drilled with conventional SBFs or diesel-based mud.

Hydraulics modeling was performed throughout the interval to determine ECD and hole-cleaning efficiency because of the sensitivity to lost returns of the drilling fluid and the maintenance of wellbore stability. The modeled ECD remained extremely consistent with PWD values (**Fig. 2**). For example, the calculated ECD while sliding at 12,236 ft MD was 15.763 lb/gal; the ECD measured by PWD at the same depth was 15.65 lb/gal, a scant 0.11-lb/gal difference. Temperature effects on the EMW were also modeled with the hydraulics software, as shown in the example results calculated at 13,100 ft TVD.

The interval was drilled to TD at 13,239 ft MD (12,858 ft TVD) with a final mud weight of 15.8 lb/gal. Hole opener runs were made before logging and before running 9 5/8-in. casing. During each hole opener run, minor losses were encountered in the same zone and readily cured with the same lost-circulation treatment.

Zero Losses While Running and Cementing 9 5/8-in. Liner

To minimize losses while running and cementing the 9 5/8-in. liner, both closed- and open-ended runs were modeled. The software generated a set of profiles showing the impact of different running speeds on ECD (**Figs. 3 and 4**). The 9 5/8-in. liner was run to the planned depth of 13,239 ft MD at speeds up to 60 ft/min with zero

mud losses, despite the existence of the loss zone at 12,858 ft. The liner was circulated at 6.0 bbl/min and cemented in place. Full returns were maintained throughout the entire operation. A formation integrity test (FIT) yielded an 18.0-lb/gal shoe test. No remediation work was necessary for the primary cement job.

The well plan allowed eight drilling days for the 12 ¼-in. interval. The interval was actually drilled to TD in seven days (96 rotating hours). No evidence of barite sag was observed after trips or after logging. The actual drilling fluids cost was 22% less than the planned cost for the interval.

The 8 ½-in. Interval

With the 9 ⅝-in. liner set successfully at 13,430 ft MD, drilling continued with an 8 ½-in. PDC bit and the clay-free SBF system. The hole angle was dropped from 38° to 33° while drilling to TD at 15,747 ft MD (14,868 ft TVD). The maximum mud weight was 16.8 lb/gal. The ECDs were constantly modeled and correlated closely with PWD values (Fig. 5). While drilling 50 ft/hr at 15,000 ft MD, for example, the calculated ECD was 16.874 lb/gal and the PWD measured density was 16.9 lb/gal. The maximum BHT in this interval was 247°F. The temperature effect on EMW continued to be modeled for this interval (Fig. 6).

Zero Barite Sag

At 16.9 lb/gal in the deviated well, the potential for barite sag was very high. The mud weights in and out were recorded every 15 minutes while circulating, with close scrutiny applied after trips and other static intervals. Variation in density occurred rarely, and the maximum variation observed was 0.1 lb/gal or less. Maximum and minimum mud weights recorded by the PWD consistently confirmed the surface readings.

The rheological properties of the SBF system were relatively low considering the demands created by high density and high temperature. The funnel viscosity remained 80 sec/qt or less except after several days of logging, when the funnel viscosity was recorded at 90 sec/qt. The yield point was 10 to 13 lb/100 ft². Ten-second/ten-minute gels averaged 12 to 25 lb/100 ft². The HPHT fluid loss was controlled at 10 mL/30 min.

The ability of the unique SBF system to prevent barite sag while also reducing whole mud losses that typically occur with conventional SBFs has been attributed in part to the character of the gel strengths.¹ The fluid forms robust gels quickly, allowing excellent suspension. However, the gels are very fragile so that relatively slight pressure is required to initiate circulation, and surge pressures are minimized while tripping and running pipe. The PWD logs from wells drilled with the clay-free SBF in shelf and deepwater locations verify the absence of the "pressure spike" commonly associated with resuming circulation after a long static period.

Zero Losses While Running and Cementing 7 ⅝-in. Liner

The hydraulics modeling software was used again to calculate both closed- and open-ended casing runs (Figs. 7 and 8). A 2,810-ft, 7 ⅝-in. liner was run to the planned depth of 15,747 ft MD at speeds up to 50 ft/min with zero mud losses during running, circulating, and cementing operations. An FIT yielded an 18.5-lb/gal shoe test. No remediation work was required.

The well plan allowed eight drilling days for the 8 ½-in. interval. The interval was actually drilled to TD in seven days (115 rotating hours). The actual drilling fluids cost was 1% higher than the planned cost for the interval.

The 6 ½-in. Interval

The final interval registered a maximum static BHT of 335°F. Flowline temperatures ranged from 130°F to 170°F. The well angle was dropped to 30° and drilling continued to the planned depth of 17,015 ft MD.

No hole problems were noted while tripping before the TD logging run. However, the wireline logging tools would not go past 16,615 ft. A hole opener run was made and a weighted sweep was circulated around before pulling out of the hole to resume logging. After an unsuccessful attempt at wireline logging, another hole opener run was made. Pipe-conveyed logging tools were run in the hole to bottom with no problem. The well was eventually plugged back to 15,675 ft MD. A 7 ⅝-in. tieback was run to surface and cemented.

The correlation between modeled ECD and PWD data continued to be very accurate throughout the 6 ½-in. interval (Fig. 9). Over the course of the entire well, the average difference between calculated and measured ECD was 0.029 lb/gal. No evidence of barite sag was detected.

The well plan allowed nine drilling days for the 6 ½-in. interval. The interval was actually drilled to TD in three days (47 rotating hours). The actual drilling fluids cost was 19% less than the planned cost for the interval.

Conclusions

The use of the highly accurate hydraulics modeling software allowed the operator to predict the cuttings load that would result from a given ROP at a given pump rate and determine the impact of the cuttings load on ECD.

Accurate knowledge of the ECD and hole-cleaning efficiency helped the operator maximize ROP while minimizing the risk of lost circulation or hole packoff. On the No. 2 well, the operator was able to achieve ROPs of up to 130 ft/hr without negative consequences. The 12 ¼-in., 8 ½-in., and 6 ½-in. hole sections were drilled in 18 drilling days (258 rotating hours), seven days less than planned, resulting in reduced rig costs of approximately \$100,000 per day saved.

The ability to model surge and swab pressures before running each casing string allowed the operator to select the optimal running string speed and avoid costly whole mud losses. This was especially notable in the 12 ¼-in. interval, where a significant loss zone had been encountered. No downhole mud losses occurred while running and cementing each of the three liners. The total mud cost for the three intervals was \$676,276, which is 17% lower than the planned cost of \$814,400.

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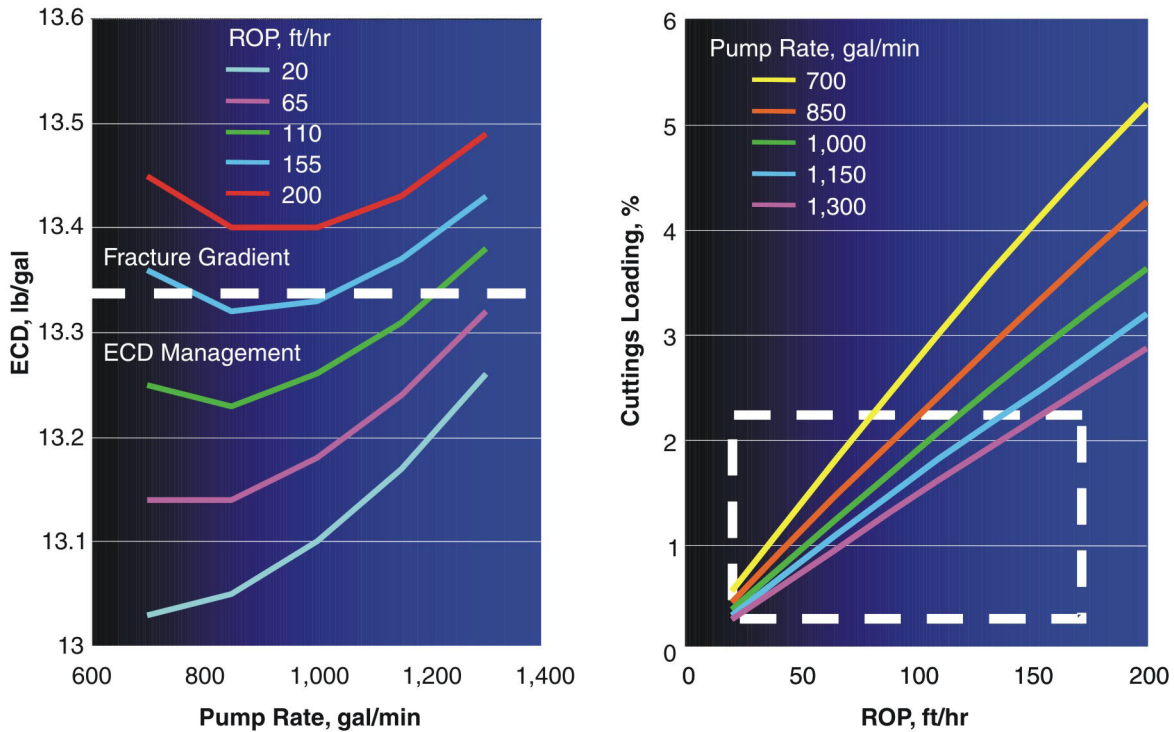


Fig. 1—Optimal ROPs based on ECD and cuttings loading are shown in drilling window at right

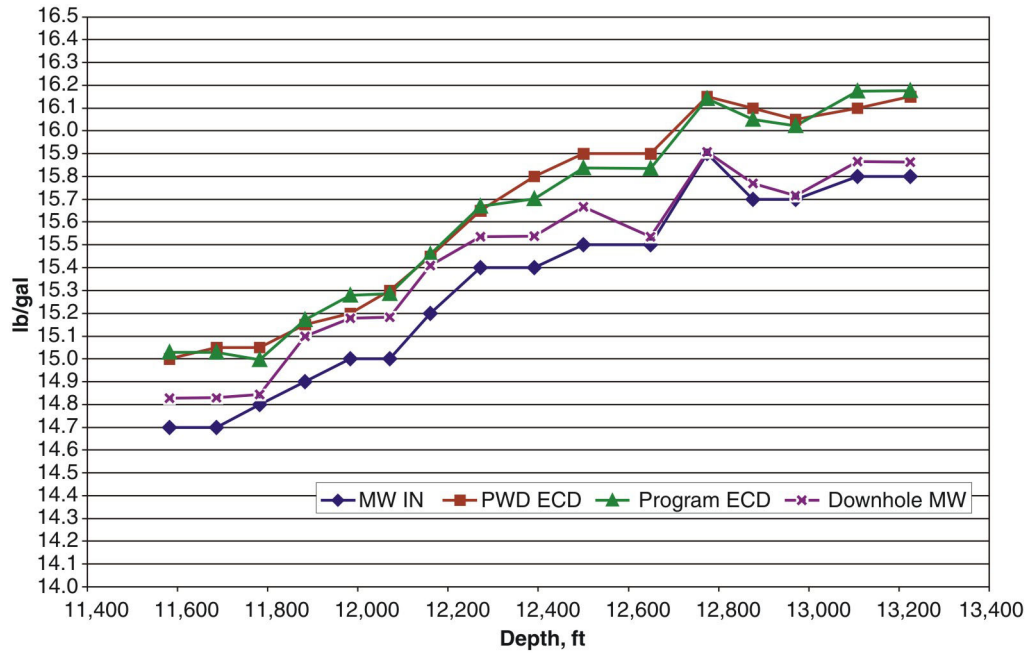


Fig. 2—Comparison between modeled ECD and actual PWD data in 12 ¼-in. interval

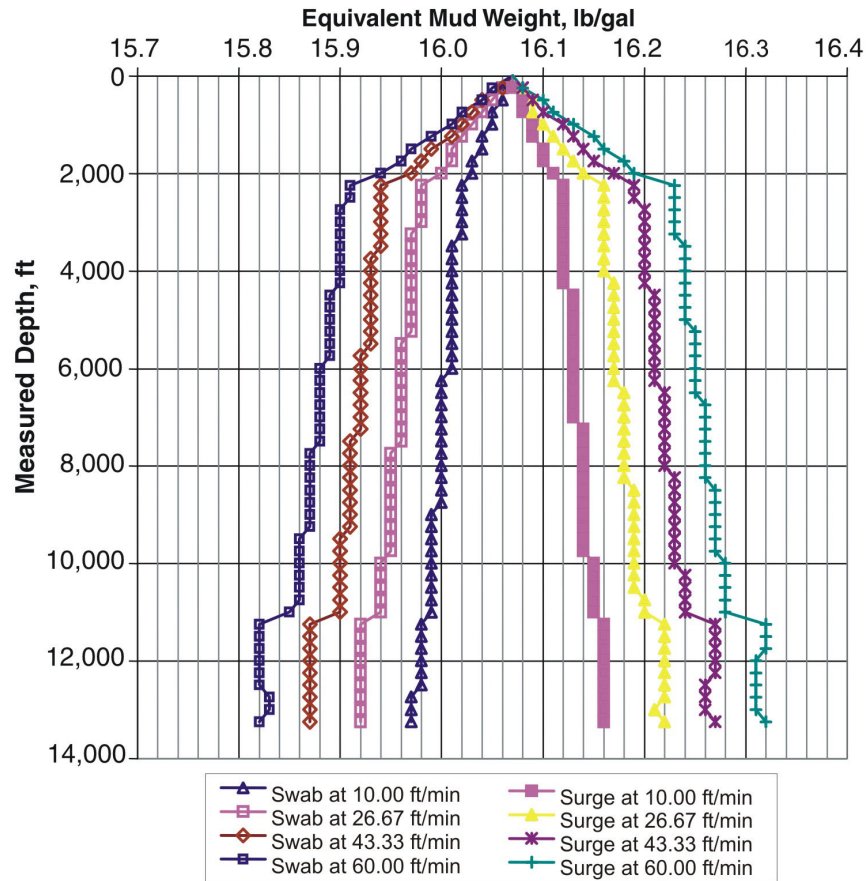


Fig. 3—Closed-end surge and swab for 9 5/8-in. liner run

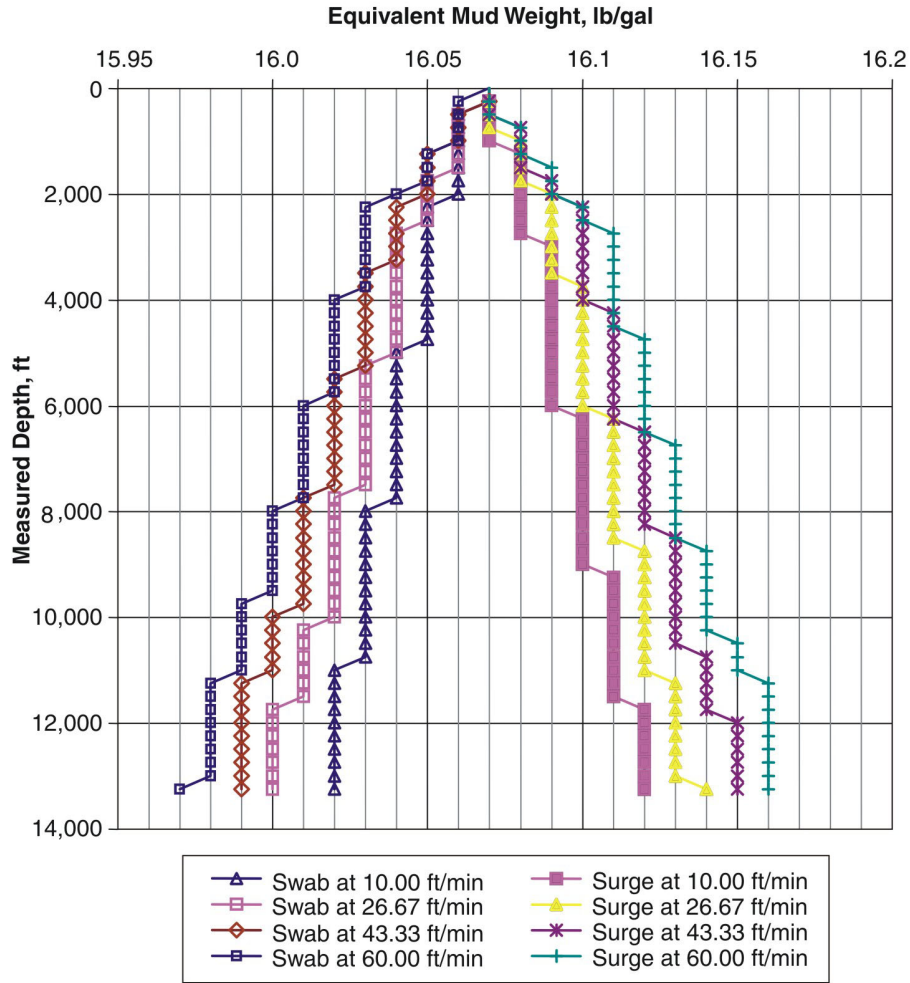


Fig. 4—Open-end surge and swab for 9 5/8-in. liner run

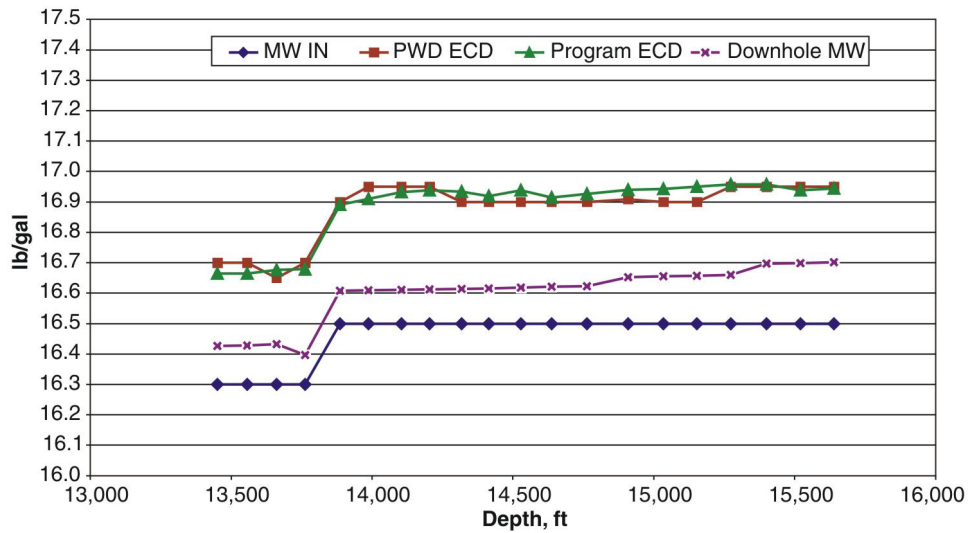


Fig. 5—Comparison between modeled ECD and actual PWD data in 8 1/2-in. interval

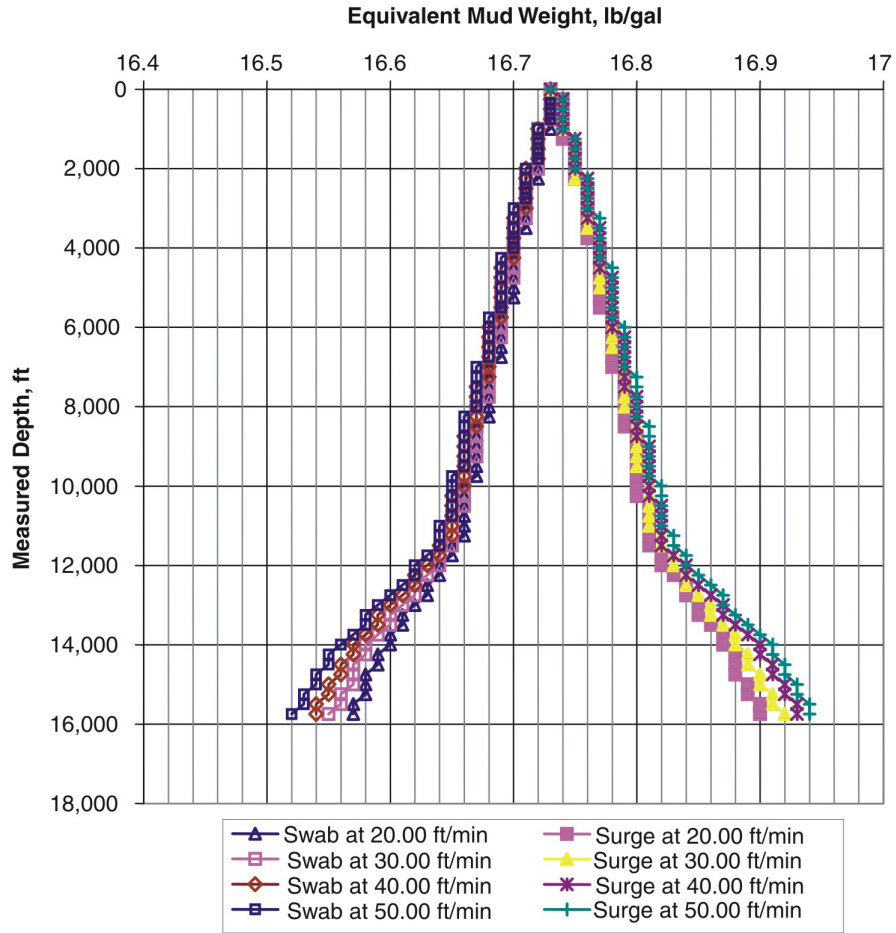


Fig. 7—Open-end surge and swab for 7 5/8-in. liner run

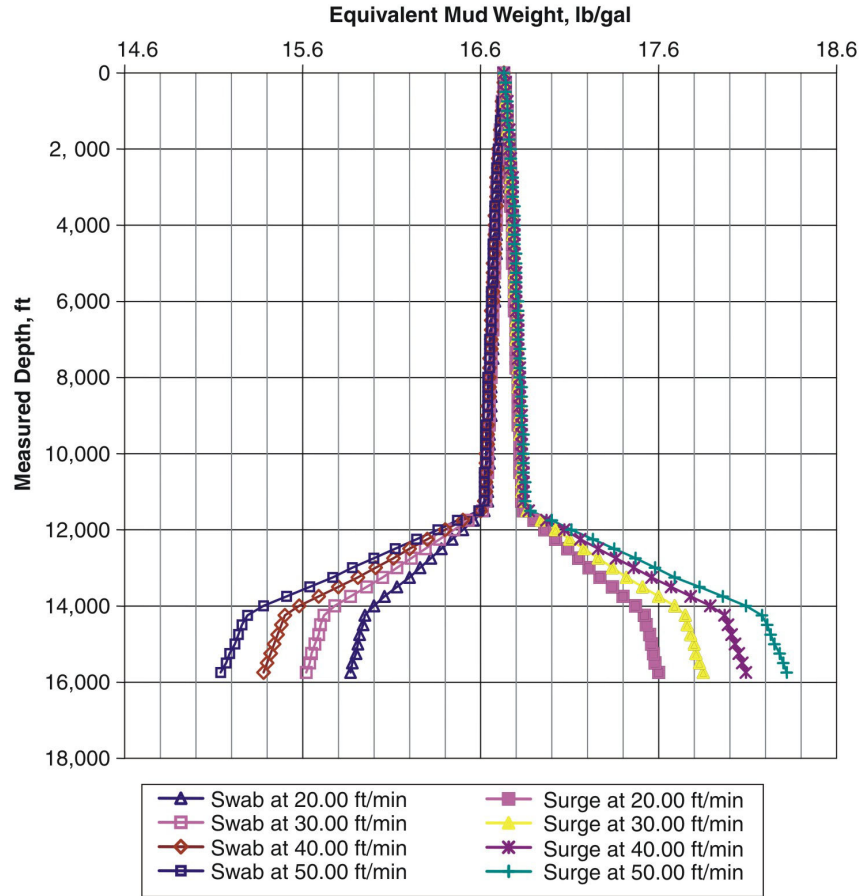


Fig. 8—Closed-end surge and swab for 7 5/8-in. liner run

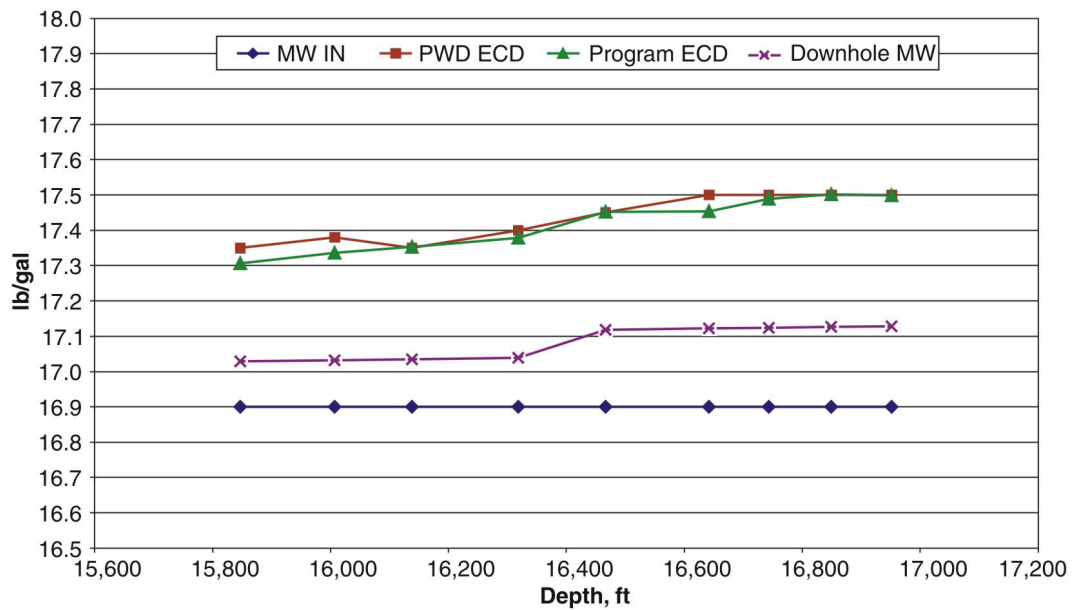


Fig. 9—Comparison between modeled ECD and actual PWD data in 6 1/2-in. interval