Making Frac-Pack Headway in Offshore Guinea

THE SETTING

- High Perm Offshore Completions
- Improving Previous Poor Results
- Tip Screen Out Modeled and Executed

Pinnacle

THE SETTING

Amerada Hess's Ceiba Field is located in about 2500 ft water depth off the coast of Equatorial Guinea. The oil productive interval is characterized by a 100- to 650-ft section of laminated sand-siltstone-shale sequences (8,200 ft TVD, 205°F). Well deviation through the pay ranges from near vertical to 60 degrees. There are several high permeability but poorly consolidated sands targeted for frac-pack completion, with permeability ranging from 100 to 1,000 mD.

Initial frac-packs were unpredictable, experiencing early wellbore screen-outs and unpredictable tip screen-out (TSO) behavior—with proppant volumes varying from 10 to 160 klbs and TSO net pressure increases ranging from 100 to 1,500 psi. Previous fracture modeling approaches did not reliably predict frac-pack TSO behavior using mini-frac data, which is essential to optimize pad size and proppant schedule and achieve design goals.

PINNACLE PEFORMS

Pinnacle reviewed previous frac-pack treatments, log-derived rock mechanical data and radioactive tracer information to develop a fracture modeling approach that would reliably predict TSO behavior using mini-frac data.

After reliable analysis procedures were developed, it was clear that mini-frac fluid efficiency and net pressure varied dramatically in the Ceiba frac-packs, with efficiencies ranging from less than 5% to over 30% and net pressure ranging from 170 to 900 psi. After reviewing rock mechanical data and evaluating various fracture modeling approaches, the variations in net pressure were attributed to complex fracture growth due to high wellbore deviation and long perforated intervals (as opposed to differences in Young's modulus).

Complexity & Variability

The C-18 had been completed in two intervals using separate frac-pack treatments. (Figure 2). The frac-pack treatments in the C-18 illustrate the significant variability in treatment behavior in the Ceiba field. Wellbore deviation through the reservoir section was 41° and over 200 ft of interval was perforated in each pay zone, resulting in increased risk of fracture complexity.

C-18 Lower

The C-18 Lower mini-frac indicated very low fluid efficiency of ~1% and high fracture complexity. The C-18 Lower fluid efficiency was extremely low and signaled potential frac-pack placement problems. Only 13 klb of proppant were placed in the formation, leaving 26 klb of 20/40 Carbolite in the wellbore. The proppant concentration at the perforations at the end of the job (EOJ) was only 1.7 ppa. The early wellbore screen-out resulted from extremely low fluid efficiency combined with fracture complexity.

Figure 3 shows the net pressure match of the C-18 Lower frac-pack using the mini-frac match parameters. The calibrated fracture

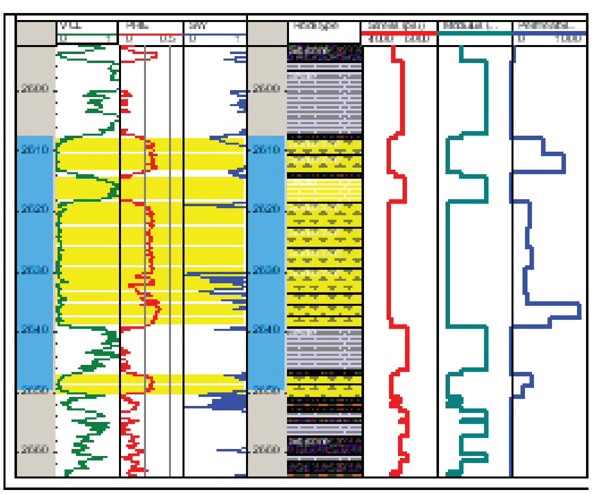

Figure 2. C-18 Log

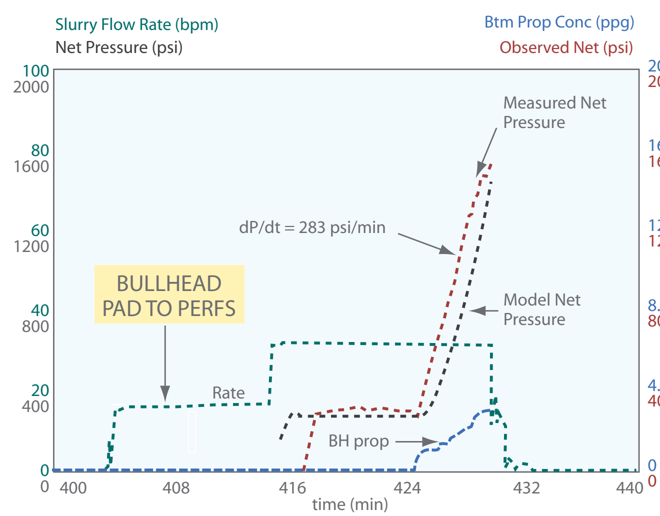

Figure 3. C-18 Lower Net Pressure Match

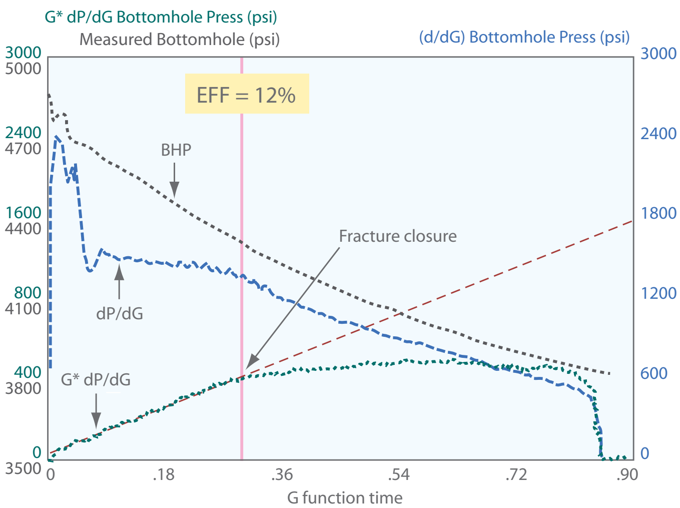

Figure 4. C-18 Upper Mini-Frac analysis

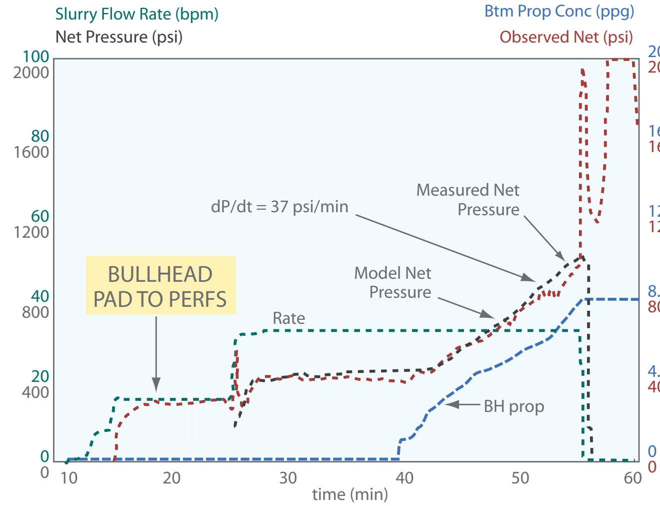

Figure 5. C-18 Upper Net Pressure Match

model reliably predicts the severe TSO behavior, with BHP increasing at a rate of 283 psi/min, resulting in a net pressure increase of ~1,300 psi during the TSO.

C-18 Upper

The C-18 Upper mini-frac analysis (Figure 4) indicated a fluid efficiency of 12% and fracture model net pressure matching indicated high fracture complexity. The C-18 Upper frac-pack treatment exhibited a modest increase in BHP during the proppant stages, with a premature screen-out when 8 ppa proppant reached the perforations. The treatment placed 77 klb of 20/40 Carbolite in the formation, leaving 46 klb of proppant in the tubing and screens.

The premature screen-out was probably due to an aggressive proppant schedule that called for a large amount of proppant to be pumped at 8 ppa combined with high fracture complexity. Figure 5 shows the net pressure match of the frac-pack data, illustrating excellent agreement between the measured and model-predicted net pressures. Again, all mini-frac match parameters are honored in the frac-pack net pressure analysis.

Lessons Learned

The primary factors that contributed to premature wellbore screen-outs were complex fracture growth (not accounted for in previous fracture modeling), combined with overly aggressive treatment designs. The primary indicators of treatment problems were the slope of the proppant ramp and the rate TSO pressure increase. Premature screen-outs were likely if TSO pressure increases exceeded 50 psi/min or 750 psi.

Based on the evaluation of initial Ceiba frac-packs, the designs and procedures for later treatments were altered. The goal of these changes was to improve proppant placement efficiency and interval coverage, while also achieving the designed TSO net pressure increase. The primary changes were:

- Application of a calibrated fracture model that included fracture complexity that reliably predicts TSO behavior to optimize pad size and proppant ramp.
- Pad size that results in a TSO pressure increase of 20 to 50 psi/min.
- Target net pressure increase during TSO should be 500 to 750 psi.
- Less aggressive proppant ramp that increases between 75 and 150 bbl/PPA and has a slope between 0.2 and 0.4 PPA/min.
- Elimination of step-rate tests, as they increase fracture complexity
- Fracture initiation using cross-linked fluid, which reduces fracture complexity

THE RESULTS

Implementing the above changes reduced premature screen-outs and allowed more predictable frac-pack TSO predictions using mini-frac data.

The study resulted in improved designs, better execution procedures, more predictable TSO behavior and a reduction in early screen-outs.

For more information on this project, see SPE 95514.

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