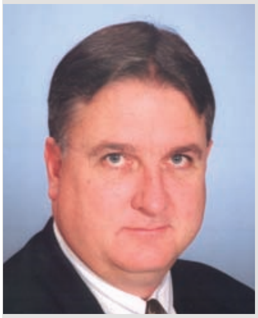
HP/HT Challenges



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HP/HT operations remain a high interest for the industry as deeper reservoir plays are pursued around the globe. Deeper horizons inherently create trends toward higher pressures and higher temperatures, adding to the complexity that the increased loads of such deep targets entail. Addressing these challenges requires careful engineering practices and attention to detail.

The industry has an extensive and successful track record in dealing with HP/HT developments with 15-ksi systems introduced in 1957, 20-ksi systems in 1972, and 30-ksi systems in 1974. Ensuring that lessons learned and technical outcomes of HP/HT projects are accumulated over many years of industry activity is a pivotal area of focus for current industry personnel. Additionally, advances in computational capabilities, materials science, nondestructive testing, seal technologies, and wellbore and component simulation all bring further measures for integrity assurance that extend and fortify earlier engineering approaches to HP/HT developments.

Industry standards also play an important role to ensure that HP/HT exploration and development projects are accomplished in a safe and reliable manner. To this end, focused work groups within standardization organizations including the American Petroleum Institute and the International Organization for Standardization have been developing guidance standards for the next generation of HP/HT developments. The industry continues to make firm strides in the development and qualification of next-generation HP/HT equipment including the industry's first 20-ksi, 18¾-in. subsea-wellhead systems and the industry's first 20-ksi, 18¾-in. blowout preventer.[1] In parallel with these surface- and mudline-equipment advances, downhole drilling systems are being advanced in notable ways. Through a collaborative agreement between major operators and a major service company, downhole drilling systems are being developed with objectives including an operating rating of 450°F and a survivability rating of approximately 500°F.

Finally, in terms of heavy-load handling and the deep-drilling aspects of HP/HT, leading drillpipe manufacturers now can provide metallurgies up to 165 ksi to address high-tensile-strength-design requirements. Across many fronts, substantial advances have been made and continue that provide the basis for the industry to address the next generation of HP/HT developments successfully. **JPT**

HP/HT Challenges additional reading available at OnePetro: www.onepetro.org

SPE 138957 *• "It Is All About Pressure: Drilling a High-Pressure Well in Record Time Using Real-Time Tools" by Gustavo Santos, Ecopetrol S.A., et. al.*

SPE 136884 *• "Ensuring Well Integrity in HP/HT Wells: Brunei Case Study" by Salim Taoutaou, SPE, Schlumberger, et al.*

SPE 130716 *• "Material Selection for HP/HT Developments" by J. Marsh, Wood Group Integrity Management, et al.*

[1]Whitby, M.F. and Kotrla, J.E. 20-ksi BOP Stack Development. Paper 128477 presented at the 2010 IADC/SPE Drilling Conference and Exhibition, New Orleans, 2–4 February. doi: 10.2118/128477-MS.

Understanding and Managing Bottomhole-Circulating-Temperature Behavior in Horizontal High-Temperature Wells

While high-temperature (HT) wells have always presented drilling challenges, the recent activity increase in the Haynesville shale along the border of Texas and Louisiana presents an extreme environment for drilling equipment. Along with a high frequency of temperature-related measurement-while-drilling (MWD) and logging-while-drilling (LWD) failures, the profile and architecture of Haynesville wells have provided an opportunity to study and understand the thermal behavior of horizontal HT wells in general. Thereby, well-specific operational guidelines and planning considerations can be implemented to reduce the risk of downhole temperature-related failures.

Introduction

The Haynesville covers approximately 9,000 sq miles. The Haynesville basin could contain up to 250 Tcf of technically recoverable gas, making it one of the largest gas plays in the USA. Production is from the Bossier and Haynesville shale formations, which correspond in many areas, so the names often are used interchangeably. The Haynesville has average thickness of 200 to 300 ft, and the depth ranges from 10,500 ft in the northwestern part of the basin to 13,500 ft in the southeastern extremities. This play is one of the deepest shale plays, and, therefore, downhole conditions are more difficult. Bottomhole temperatures (BHTs) have been measured on the order of 380°F.

A typical Haynesville well requires 35 to 45 days to drill. The intermediate section may be drilled with either water-based mud (WBM) or oil-based mud (OBM), at the operator's discretion. Soft sediments are encountered in the upper section below surface casing, but very hard and abrasive zones are found in the lower portion when passing through the Travis Peak and Cotton Valley formations. Completing the intermediate-hole section in a single polycrystalline-diamond-compact-bit run is difficult. Most horizontal sections in the Haynesville are drilled with OBM and experience high bottomhole circulating temperatures in the range of 300 to 350°F, mud weights of 15 to 17 lbm/gal, and high stand-pipe pressures of approximately 4,000 psi.

The combination of OBM, high temperature, and high solids content in the mud is a challenging environment for downhole motors, but motor failure is not the leading cause of unplanned trips. Often, the high bottomhole circulating temperatures exceed the normal temperature rating of MWD/LWD electronics, typically 302°F. To address this need, some directional-service companies offer specially screened tools rated to 320°F while others offer high-temperature tools rated to 350°F. Even with this technology, recent trends indicate that the leading cause of unplanned trips in the Haynesville is likely to be failure of the MWD/LWD electronics.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 140332, "Understanding and Managing Bottomhole Circulating Temperature Behavior in Horizontal High-Temperature Wells—A Case Study Based on Haynesville Horizontal Wells," by ***Keith Trichel,*** *SPE, and* ***John Fabian,*** *SPE, Baker Hughes, prepared for the 2011 SPE/IADC Drilling Conference and Exhibition, Amsterdam, 1–3 March. The paper has not been peer reviewed.*

Project Background

This case study was undertaken at the request of an operator in the Haynesville after drilling a horizontal well with a maximum observed downhole circulating temperature of 338°F that required multiple trips because of temperature-related MWD/LWD failures. The effort was to evaluate temperature trends observed in the well and recommend modifications to operating procedures that might extend the life of the MWD/LWD electronics. The scope also included investigating the potential effects that mud coolers or mud chillers could have on bottomhole circulating temperatures.

The results of temperature modeling concluded that the bottomhole circulation temperature in a typical horizontal Haynesville well can rise above the static BHT. This finding, combined with sensitivity modeling, also explains inconsistencies in interpreting actual static BHTs in the absence of log data. The most significant conclusion reached in this study was that the pressure drop through the bottomhole assembly (BHA) has the most influence on bottomhole circulating temperature.

Study Methodology

Because the preliminary modeling produced results that were somewhat counterintuitive, the overall approach and scope of the study were refined. The goal was to develop a better understanding of the thermodynamic behavior of horizontal wellbores, as well as gain confidence in the ability to use predictive modeling to understand cause/effect and determine the factors contributing to the drilling environment and discover which ones have the biggest effect on bottomhole circulating temperature. The refined scope followed these steps.

1. Drilling-system energy balance—Investigate the hydraulic and the mechanical contributions to heat gen-

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erated during the drilling process to better understand the thermodynamic behavior behind the temperature-modeling predictions.

2. Heat-source distribution—Use torque/drag combined with hydraulics modeling to determine the distribution and location of major heat contributors for the case-study well.

3. Data correlation—Correlate the MWD/LWD temperature data from tool memory with actual drilling-parameter data from the rig's surface recorder to determine the effect that drilling parameters have on bottomhole circulating temperature.

4. Temperature-model calibration—Use data from the rig's surface recorder as input into the temperature model to calibrate the bottomhole circulating temperature predicted by the temperature model to the MWD/LWD-probe temperature recorded in the tool's memory.

5. Sensitivity test and cause/effect analysis—After the temperature model is calibrated to match tool-memory data, the model can be used to analyze sensitivity to changes in the drilling environment and the impact of cause/effect relationships on the bottomhole circulating temperature.

Results

Table 3 in the full-length paper contains a summary of the results from the sensitivity and cause/effect analysis. The outputs from each temperature-modeling simulation can be found in the appendix.

Simulations With Mud Coolers and Mud Chillers. Here, mud coolers refers to devices that use atmospheric air forced over heat exchangers to remove heat from the drilling fluid at the surface. A mud chiller is a device that uses a refrigeration unit to remove heat from the drilling fluid. Both types of units can be configured to process mud from the mud pits on the surface at a rate several times the flow rate being pumped down the drillpipe.

The case-study well did not use either device, so it was strictly a simulation exercise with the temperature-modeling software to assess their effectiveness. Both types of devices were simulated. The coolers were simulated with a 20°F drop from flowline temperature to suction temperature. The chillers were simulated with a constant suction temperature of 75°F. The simulations showed that both devices should limit flowline-temperature rise over time and result in lower mud temperature at the surface. While this has benefits from a health, safety, and environmental standpoint, neither device was predicted to have any significant effect on reducing the bottomhole circulating temperature at the end of a 4,000-ft-long horizontal section for this specific case-study well.

A nearby well that did use a mud chiller was simulated with data collected from daily mud reports. The data consisted of surface- and downhole-temperature readings from each report along with the reported flow rate and drilling-fluid properties. While there are no downhole-temperature-memory data to calibrate against, as with the case-study well, the model simulations matched closely with data points recorded in the mud reports. This nearby well used flow rates ranging from 170 to 210 gal/min and used a smaller drillstring and hole size. In this case, because the well used a chiller, the simulation had to be made to determine what would happen without it. This simulation suggests that BHT reduction achieved with a mud chiller diminishes with increasing lateral length. In this case, there was a reduction in temperature of approximately a 6°F predicted by the end of the horizontal section, but as much as a 20°F reduction at the beginning of the horizontal section.

The results presented in the sensitivity test and cause/effect analysis represent only a small portion of the numerous temperature-modeling simulations conducted during the course of this study, but were chosen as relevant examples. To keep the full-length paper at a reasonable length, the results of all the simulations were not presented. Conclusions were based on the understanding gained throughout all of the modeling simulations, including those not presented in the paper.

Optimization and Planning

The following operational guidelines and planning considerations are targeted specifically toward horizontal Haynesville wells in which bottomhole circulating temperature is expected to cause electronics failures. BHT varies within the Haynesville field, and not all areas report bottomhole circulating temperatures that exceed the limits of the MWD/LWD electronics. These recommendations are appropriate for wells in those areas of the field where temperature-related issues are common.

1. For planning purposes, use temperature data obtained from offset-well logs after the well has reached thermal equilibrium. Do not assume geothermal gradients based on bottomhole-circulating-temperature projections. There is too much uncertainty involved, and the bottomhole static temperature may be less than the circulating-temperature measurements recorded by MWD/LWD equipment.

2. If accurate bottomhole-static-temperature data exist, then use temperature modeling as a planning tool to predict circulating temperatures and determine what actions can be taken to minimize them.

3. When circulating temperatures are anticipated to exceed the limit of the MWD/LWD electronics, consider the use of thermally stable inhibitive WBM systems as an alternative. This choice needs careful consideration and planning because there is little experience with WBM in the area.

4. Optimize bit design (blade count and junk-slot configuration) to use the largest total-flow area possible without inducing balling issues. Increasing bit total-flow area will minimize the temperature rise in the drilling fluid caused by bit-pressure loss; however, balling issues have been known to occur in the Haynesville, even with OBM. The bit should be designed for efficient cuttings removal, even with low values of hhp/in^2.

5. Minimize BHA pressure drop to the extent possible to minimize the circulating temperature. There are limits to what can be achieved with a steerable motor BHA, but the following steps can be taken keeping the tradeoffs in mind. Minimize mud weight to the extent possible, and weigh against effects on borehole integrity. Minimize flow rate to the extent possible, and weigh against decrease in motor performance, rate of penetration, and hole-cleaning capability. Avoid unnecessary restrictions in the BHA, and set up MWD/LWD to function at reduced flow. Consider use of a torsional-rocking devise for improved weight transfer during sliding instead of a pipe-vibrating device.

6. Implement revised HT operating procedures to help manage the bottomhole circulating temperature in horizontal Haynesville wells. Some simple changes are suggested below:

- Pull off-bottom and circulate at reduced flow before making connections. The BHA-heating effect caused by differential pressure will be reduced, and hot mud in the annulus will be displaced with mud a few degrees cooler opposite the BHA. This will help reduce the temperature spike seen at pumpoff events.
- Circulate off-bottom at reduced flow for an extended period if it is desired to cool the entire wellbore before a trip. This method can be used during drilling, but simulations predict that the temperature will return to its previous value in a short time.
- Avoid staging in the hole with circulation after a trip once the BHA is past the point in the horizontal section at which the circulating temperature rises above the static geothermal gradient. This method will increase circulating temperature in the well only when this changeover point is passed.

7. Implement a training program for both office and field personnel to educate them on the unique and often counterintuitive circulating-temperature behavior of horizontal Haynesville wells. This training program should include revised operating procedures.

8. If bottomhole circulating temperatures become problematic, consider switching to a rotary-steerable system that requires significantly less BHA pressure loss and will result in lower circulating temperatures. For the case-study well, the motor consumed approximately 1,027 psi of pressure drop and is the largest contributor to wellbore heating from the BHA pressure drop. For this method to be an effective means of circulating-temperature reduction, the rotary-steerable system should not be powered by a downhole motor and should not require excessive bit-pressure drop to provide steering force. There could be a tradeoff in instantaneous rate of penetration, but the upside would be reduced circulating temperature and increased run length. **JPT**

Managed-Pressure Drilling To Counteract Lost-Circulation and High-Pressure-Gas Zones: South Wapiti Red Rock Field

Use of heavy mud weight (MW) to control high-pressure (HP) -gas and lost-circulation zones at the same time is a challenge. The Red Rock field in the South Wapiti area in Alberta experienced this combination, which resulted in high operational costs, primarily caused by an additional casing string, high MW, and severe mud losses. On average, costs were 20% higher than anticipated, making this drilling program uneconomical.

Introduction

The Red Rock field is in the Deep basin of western Alberta, where much of the gas is found in low-porosity, low-permeability reservoirs deposited in an epicontinental seaway. The Deep basin is unique in that porous rocks are water saturated updip to the east and gradually become gas saturated and less porous downdip to the west.

The Falher section (overlying the Gething formation) is overpressured in the area, but there is more confidence in predicting the presence on a broad scale. Coals are found throughout the Falher and Gething formations and must be considered. Historically, lost circulation has occurred in the Falher section at elevated MWs, also into several coal seams in a few cases. Recent wells have experienced kicks in the Bluesky, Gething, and Falher zones, which have driven MWs higher to manage risk. Further uphole, the Doe Creek and Dunvegan formations have been pinpointed as a main lost-circulation section in the area. Natural fractures exist in the wider area across this section, which supports the determination that these zones cause lost circulation.

*This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 137428, "Successful Use of Managed-Pressure Drilling To Counteract Lost-Circulation and High-Pressure-Gas Zones: A Case Study From the Red Rock South Wapiti Field in Grande Prairie, Alberta, Canada," by **Hassan K. Malik,** SPE, **Raymond J. Litwin,** SPE, and **Bernard C. Jones,** ConocoPhillips Canada, prepared for the 2010 Canadian Unconventional Resources & International Petroleum Conference, Calgary, 19–21 October. The paper has not been peer reviewed.*

Red Rock Drilling Challenges

Wells in this area are drilled with an invert-oil-based-mud (OBM) system, which is used in the field with consistent success in keeping reactive shales stable. The use of OBM systems, with high oil/water ratios, is costly in lost-circulation situations. Wellbore-strengthening materials have been used to varying degrees to mitigate losses while drilling the usual problem zones. This is seen when drilling into the Doe Creek and Dunvegan formations with low MWs (930–980 kg/m^3) and losses are encountered. A regime of adding wellbore-strengthening materials before penetrating these zones helps heal the losses, and in several cases allowed the MW to be increased deeper in the well. This technique is an important tool in this area to drill through loss zones.

A review of offset-well information within a 2-km radius was made. The first several wells (Numbers 1 through 4) set intermediate casing above the first overpressured zones in the Falher section. When drilling below intermediate casing and weighting up for Bluesky and Gething, losses were encountered in the Falher section. Wells 5 through 7 used wellbore strengthening and reached total depth without setting intermediate casing while achieving required MWs. A consequence of the higher MWs in the larger hole was slow penetration rates. Wells 8 and 9 used wellbore strengthening, but could not achieve MWs required for Bluesky overpressure, so intermediate casing was run. Drilling below intermediate casing was a challenge also. In one case, losses were seen as the intermediate-casing shoe was landed in the base of the Falher, so a coal seam was left open below. Penetration rates were challenged in the main hole section below intermediate casing also. The severity of the problems and behavior of these zones can change significantly by moving only a few kilometers away.

Managed-Pressure Drilling (MPD)

Underbalanced-drilling (UBD) or MPD operations with jointed pipe are not new technologies. Safety is of prime importance in these operations. More equipment, more people, and significantly different practices are involved in the UBD and MPD operations. However, with proper planning and with hazard and risk assessments, a UBD or MPD operation can be a safe and commercially viable technique.

Three major problems were identified in the Red Rock area.

- Lost-circulation zones in upper formations including Doe Creek and Dunvegan.
- Falher sequence with coal layers: The Falher B has gas production.
- HP-gas zone in the Bluesky and Gething formations.

After a detailed examination of these wells, UBD and MPD seemed the best solutions, but a comparison was made between the two because of their specific applications. On the basis of this comparison and the risk level associ-

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ated with these techniques, MPD was chosen as the most relevant technique to drill Red Rock wells.

Design Methodology

The issues associated with the Red Rock area were clear. Knowing the three major problems, the well was divided into two sections.

- Section 1: Lost-circulation zone
- Section 2: Falhers coal-seam-gas and HP-gas zones

MW and Pressure Profile. The pressure profile is exponential and reaches its maximum value at the junction of the Bluesky and Gething formations. The equivalent-circulating-density (ECD) curve showed the effect of using heavy mud. At a 1415-kg/m^3 density, the ECD value is approximately 1500 kg/m^3, almost 100 units more than the original MW. Geoseismic data and experience in the area showed that the fracture gradient was overestimated because of losses seen in previous wells with MWs as low as 960 kg/m^3. The starting point for any MPD design is a graph containing the pressure and MW/ECD profiles (see Fig. 6 in the full-length paper). It provides a good estimation for the drilling-operations envelope. The static hydrostatic-head line creates a boundary of the envelope. It should be noted that fracture-gradient values were taken from core samples. Seismic data indicated abundant faulting in the Doe Creek and Dunvegan formations, and drilling experience in the area showed a varied MW profile that caused fracturing in the top zones.

MWs as low as 960 kg/m^3 to as high as 1280 kg/m^3 were used as a range in the area. The gap between MW and fracture gradient is the recommended operating window. Because the fracture-gradient profile was slightly overestimated, it was decided to use wellbore-strengthening material.

Wellbore Strengthening. This procedure was designed to prevent losses mainly in the Doe Creek and Upper Dunvegan formations from approximately 1400 to 2200 m, and it required the use of an intermediate casing because of major mud losses. The plan called for the three types of products (fibrous, granular, and flake) to be added to the active system while drilling ahead and would approach the weight up gradually (150 m above the required formation on the program). Another issue was the susceptibility to surge/swab pressures during bit trips, regardless of how carefully the pipe was tripped in or out. The margin between lost circulation and drilling ahead was very small, so a separate premix of pretreated mud was stored until a tripping operation was required.

Flow Potential. The flow potential of the HP-gas zone controlled the overall design of these wells. To understand this behavior, an inflow-performance-relationship (IPR) curve was generated for the Bluesky and Gething formations. Unfortunately, there were few data available for the these formations. In the past, these formations often had been masked by heavy MW. With the help of transient tests conducted in these HP zones, an approximate-IPR curve was generated. From this IPR curve, the estimated absolute-open-flow rate was 5 MMscf/D. During the planning phase, there was no agreement on a MW; therefore, two random MW values were used to determine the effect of drawdown vs. flow rate.

Fountain Chart. A "fountain chart" evaluates the following.

- Optimum operating/drilling envelope for a special case, such as Red Rock wells.
- Optimum MW that does not fracture the weak uphole zones yet, at the same time, balances the HP-gas zones at the bottom when the surface-choke pressure is implemented.
- Represents a clear illustration of pressure profiles with respect to each MW.

From the chart in Fig. 8 in the full-length paper, a MW of 1200 kg/m^3 was determined to be optimum for drilling this well conservatively. The fountain-chart method indicated that a MW of 1200 kg/m^3 never crossed the fracture-gradient line. As a result, a small (2000-kPa) choke pressure would be required in case a gas flow of 2 MMscf/D occurred from the Bluesky or Gething formations.

This chart can be used in real time while drilling to predict flowing pressures or ECDs. It should be noted that a minute amount of gas influx, such as small and short bursts of gas, will not affect the dynamics of this chart. To change this chart, the gas flow must be continuous and remain for a significant amount of time.

Key Learnings

- Multiple wells are required for the engineering and operations teams to become familiar with any new technique.
- Safety meetings must be enhanced for the crew members on projects where new equipment is added to the rig.
- It was extremely healthy to discuss project goals during safety meetings. Each critical operation must be discussed thoroughly with crew members. An "ask-questions" atmosphere must be encouraged to avoid confusion during operations.
- A formation can be high pressured, but may not be permeable. Geologically prognosed pressures are just an estimation made on the basis of wells drilled in the area. An MPD autochoke system provides real-time formation evaluation for a given pressure value. This was achieved successfully in these four wells.
- With the amount of wellbore-strengthening material added to the system, up to 30% of total invert-OBM losses were attributed to the fluid being retained by the material and then being carried off over the shaker.
- Centrifuges on location were not capable of handling the rate and capacity of the fluid being pumped.
- Low-gravity solids will be more difficult to control with the current conventional setup of centrifuges because wellbore-strengthening materials are added along with drill solids as the rate of penetration increases. The first line of defense must be the shakers, their design, and the screen selection to maintain the active mud system. **JPT**

Stimulation Engineering Services
Drilling & Measurement Services
Coiled Tubing, E-Coil, Nitrogen
Slickline & Braided Line Hydraulic Workover
ElectricLine SpecialServices
Oil Well Firefighters and Blowout Specialists
Well Control and Emergency Response Planning

Material and Completion-Equipment Selection for an HP/HT Sour-Gas-Field Development in Indonesia

The Lematang Block in South Central Sumatra has estimated total reserves of 330 Bscf, with an expected production life of 10 years. Wells in this field contain 32% CO_2 and 100 ppm H_2S, have a bottomhole pressure (BHP) of 10,500 psi, and have a bottomhole temperature (BHT) of 408°F. The initial two wells were completed by the previous operator using 22Cr tubulars and 13Cr accessories. However, operational difficulties from material deterioration were identified. Optimization of completion durability considering economics was of high concern when selecting materials and completion-tool designs.

Introduction

The direct costs of completion hardware and long-term product performance to ensure durability for the life of each well were studied in detail before selections were confirmed. This study required the use of metallurgical and reservoir experts to provide opinions on material selection and required completion specialists to select the specific products to ensure that desired results were obtained. The workflow used to select the correct material and equipment culminated in a complex decision tree. Various analyses then were performed to support the selection of materials and the downhole equipment.

*This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 136163, "Material and Completion-Equipment Selection for HP/HT Sour-Gas-Field Development in Indonesia: Case Study," by **Gustioro Purwagautama,** SPE, and **Rizky Andika,** SPE, MedcoEnergi, and **David McCalvin,** SPE, and **Dmitry Pleshkov,** SPE, Schlumberger, prepared for the 2010 IADC/SPE Asia Pacific Drilling Technology Conference and Exhibition, Ho Chi Minh City, Vietnam, 1–3 November. The paper has not been peer reviewed.*

Background

To meet the growing demand for natural gas in the Far East, exploration and appraisal drilling was conducted on the Singa field in South Sumatra, Indonesia. This field has estimated gross reserves of more than 200 Bscf in a carbonate reservoir at 11,900 ft with a BHP of 10,500 psi and BHT of 408°F. Appraisal wells were drilled in 1997 and 1998. Both well tests showed similar results: 10,500-psi reservoir pressure, traces of H_2S, and 32% CO_2 with no water production. In 2003, the second well was completed with 22Cr tubulars, a packer, and a safety valve. After 1 year of production, the annulus pressure began to increase, indicating completion-equipment-integrity failure. Further development of the field by drilling and completing two additional wells was planned for 2008.

Critical factors, including cost, corrosion rate, life of the field, equipment lead time, gas composition, pressure, and temperature, must be assessed before finding an optimum solution. Besides the 22Cr tubular that had been used, tubular-material candidates for future wells in this field were 13Cr-HP2 and 15Cr-UHP. The operator simulated the corrosion effects on the material and searched for the optimum material to use. To optimize performance and reduce the overall completion cost, a detailed study and a series of tests were performed.

Completion-Tubular Selection

The exploration wells drilled in 1997 were completed with 22Cr material, with total tangible cost of approximately USD 2.4 million. For the next two development wells, a more durable material at a reduced cost was sought. Early corrosion tests for 22Cr showed that the corrosion rate was 0.11 milli-in./yr, suitable for Singa conditions. The plan for the Singa field was to drill two wells and recomplete one well, and each is targeted to produce a minimum of 30 MMscf/D and to have 10 years of production. Therefore, corrosion-resistant-alloy material will be needed to meet environmental requirements and to maintain integrity for 10 years. However, the cost of 22Cr material does not fit the economic criteria for this program.

Carbon composition affects steel properties and is the primary hardening element. Hardness and tensile strength increase as carbon content increases up to 0.85%, but ductility and weldability decrease. Chromium is the element essential in forming a passive film or high-temperature corrosion-resistant chromium oxide, characteristic of stainless steel. The passive film forms with 10.5% chromium, which provides limited atmospheric protection. As chromium content increases, the corrosion protection increases. A small percentage of molybdenum increases the strength of the steel at high temperature without significantly expanding or softening its physical properties, which can make steel more ductile and less easy to break.

Early corrosion testing showed that at 3,500 psi, 22Cr had a corrosion rate of 0.11 milli-in./yr while 13Cr had a corrosion rate of 26.37 milli-in./yr. However, 22Cr cost is in the range of two to three times that of 13Cr. Therefore, the project focused on identifying a material having a better corrosion rate than 13Cr but at less cost than 22Cr. Because of the

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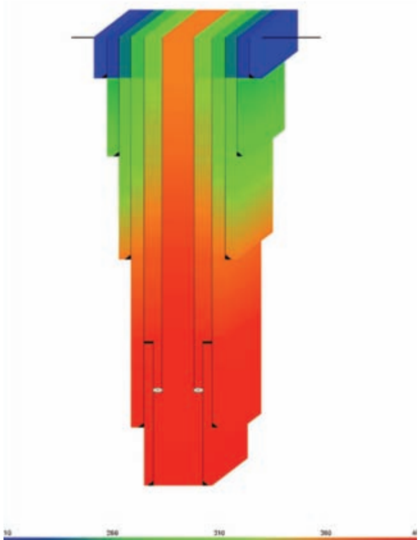

Fig. 1—Results of temperature simulation.

10,500-psi BHP, the tubular material requires strength to accommodate compression and tension even with potentially deteriorating strength resulting from corrosion. On the basis of chemical composition and yield strength, 13Cr-HP2 and 15Cr-UHP steels were selected for testing in the Singa-field environment for corrosion and integrity.

Completion-Tubular Testing

Corrosion testing showed an average corrosion rate of 6.5 milli-in./yr for 15Cr-UHP, which is acceptable for 10 years of production in the Singa field. For 100 ppm H_2S, both materials passed the requirement. The 13Cr-HP2 material showed an average corrosion rate of 25.5 milli-in./yr. The 15Cr-UHP had no indication of pitting. On the basis of this CO_2-test result, the 15Cr-UHP is acceptable for the Singa-field conditions.

Both 13Cr-HP2 and 15Cr-UHP were found acceptable in the sulfide-stress-corrosion-cracking test. There were no indications of cracking as result of introducing H_2S, which can cause material to fail when stress is applied. The test results indicated that no stress-corrosion cracking was measured on the 15Cr-UHP or the 13Cr-HP2 specimens, indicating that both materials can withstand a 100-ppm H_2S environment. Costwise, the 15Cr-UHP can be much less expensive than 22Cr.

Completion-Design Limitations

Wells that flow at high rates also increase wellhead and downhole-completion-equipment temperatures. At high temperatures, reservoir-fluid composition can change and, therefore, the temperature may be the prime driver in material and product-design selection. Because liquid transfers heat more effectively than gas, completion fluid in the annulus and produced water contribute strongly to transferring heat to the completion equipment and to the surface.

Design issues for the packer and safety valves focused on material selection, sealant technologies (static/dynamic), and reduction of casing stress caused by packer slips. After determining production parameters, reviews of the available equipment conforming to those criteria were recommended. The load capacity of tubing-mounted products typically is provided in an operating envelope that indicates product-design limits of loading and pressure in ranges of temperature.

The safety valve is a critical component of the completion string. To determine the maximum expected temperature at the safety-valve depth, a flowing simulation was performed. The simulation parameters were a flow rate of 70 MMscf/D of dry gas, a geothermal gradient of 1.5°F/100 ft, and a water-based-brine annular fluid. Results of this simulation, shown in **Fig. 1,** projected a 362°F flowing temperature at the setting depth.

Product temperature ratings for the completion equipment were 350°F, but because of the 362°F temperature estimation at the safety valve, a 400°F rating was set for it and the packer. These published ratings combined with the American Petroleum Institute (API) monogram assured the team that these products had been tested at temperatures in excess of those of the Singa wells. However, it is advised that product operation and durability be derived from service records in applications in a similar environment.

Simulation of the thermal-cycling, tubing-stress, and packer-load cases was performed also. It showed very severe tubing buckling (up to 13°/100 ft) and compressive stress on the packer, but all parameters were within design limits of the selected packer systems.

Inconel 718, with 120-ksi minimum yield strength, was selected as the metallic material for the safety valves and packers. This material was selected because of corrosion resistance and its proven long durability in production history. Both product designs were qualified at 400°F. The safety valve conforms to the API Class 3/3 criteria, and the packer was qualified at design-validation Level VO. These selections were made to ensure that the sealing elements of these products would remain intact for the projected 10-year production period.

Conclusions

The effective implementation of optimizing product and material selections, well design, and execution methods translated into long-term well integrity at the desired production rates. Because all systems and products must operate effectively the first time and for the life of the well, the detailed well-design engineering and evaluations require that the correct expertise be applied at each step in the process. This action is possible with the effective partnership of operator and contractor personnel, guided by a precise plan and focus. For the completion products, it was decided to use proven products supported by the API-monogram system to ensure consistent product quality. Hence, the challenges of these applications can be overcome when appropriate thoughtful resources and long-term value considerations are applied.

Well Singa-3 was completed in early March 2010, and after an extensive well test, it was put on production in June 2010. The Singa-3 well test revealed an unexpected H_2S presence in a 100- to 180-ppm range. The well produces at 40 MMscf/D, with 32–35% CO_2 and 260 BWPD. The water production is increasing and changing the temperature distribution. Also, it could increase the H_2S-corrosion effects on the cost-effective tubular selection. The completion products would be unaffected because of the materials selected for them. With the H_2S and water-production rates increasing, future completions in the Singa field may be re-evaluated regarding tubular corrosion at the new environmental parameters. **JPT**