# HPHT Wells

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### Introduction

The designation of high-pressure, high-temperature is given to wells that present extreme conditions to operators and service companies. The term HPHT may be applied to wells that have only high pressure or high temperature—few wells have both characteristics—but regardless of the designation, HPHT wells offer specific challenges that must be addressed if operations are to be successful. These challenges include all aspects of well construction and production, and they require operators and service companies to take approaches that can be significantly different from those used in non-HPHT wells. These approaches depend on the levels of pressures and temperatures encountered. After the anticipated pressures and temperatures are determined, guidelines and operational programs can be formulated to drill, evaluate, complete and safely produce hydrocarbons.

An oil industry study estimated that of the more than 100,000 wells drilled worldwide in 2012, about 1.5% should be classified as HPHT. Although relatively small in number, these wells often represent significant resource potential and are often located in areas where exploration in new horizons is ongoing.

### Classification System

Over the years and across companies, definitions of HPHT have varied. In 2012, the American Petroleum Institute (API) attempted to harmonize accepted terminology and classifications by publishing guidelines for equipment used in HPHT operations. The API Technical Report 1PER15K-1 *Protocol for Verification and Validation of High-Pressure High-Temperature Equipment* defines a high-pressure well as having pressure greater than 15,000 psi [103 MPa]; a well that has temperatures above 350°F [177°C] is considered high temperature. The API operating standards relate to design specifications for equipment, acceptable materials to be used in HPHT operations and the testing of well control and completion hardware to ensure safety, suitability and integrity. According to the API publication, three additional criteria qualify a well for HPHT classification:

- anticipated surface conditions that dictate completion and well control equipment rated above 15,000 psi
- anticipated shut-in surface pressure in excess of 15,000 psi
- flowing temperature at the surface in excess of 350°F.

Schlumberger further defines and classifies HPHT specifications based on a system that takes into account thermal stability of design components (such as elastomeric seals), suitability of electronics and pressure ratings of hardware (Figure 1).

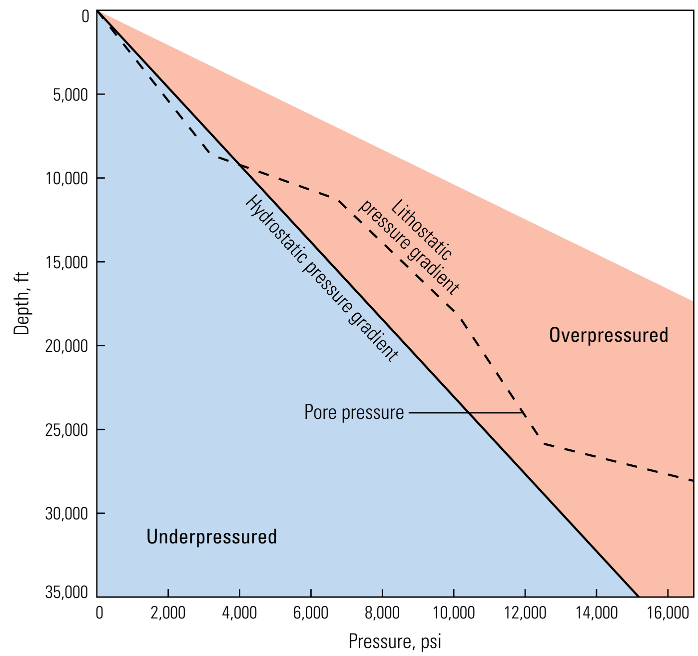


Figure 2. Pressure gradients. The hydrostatic pressure gradient (black line), assuming seawater, is 0.43 psi/ft [9.79 kPa/m]; it follows a straight line. The lithostatic pressure gradient (dashed black line) represents the actual downhole pore pressure and is a product of fluid, overburden and abnormal pressures; it can change across geologic features such as faults and depleted reservoir zones. Underpressured reservoirs (blue) have pressure below the hydrostatic gradient; overpressured conditions (pink) have pressures above the hydrostatic gradient.

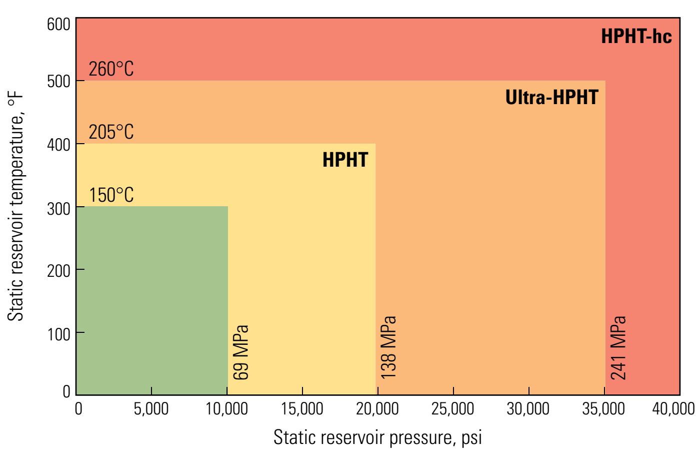


Figure 1. Schlumberger HPHT classification system. This classification system is based on pressure and temperature boundaries that reflect stability limits of common components used by Schlumberger, which include electronics, hardware and sealing elements. The HPHT-hc classification defines environments unlikely to be seen in oil and gas wells, although geothermal wells may exceed 500°F and some deepwater wells have downhole pressures that exceed 35,000 psi.

### Pressure Challenges

Drillers are usually the first to contend with downhole pressure, specifically pore pressure—the pressure of fluids within the pores of reservoir rocks. Pore pressure increases as depth increases because formations must support the overburden above them (Figure 2). Pore pressure follows a pressure gradient—the rate of increase in pore pressure versus depth that can change rapidly across geologic features. To prevent formation fluids from entering a wellbore while drilling, engineers use weighted drilling fluid. The hydrostatic pressure in the wellbore created by the drilling fluid counteracts the formation pore pressures and prevents fluid influx. Consequently, drillers must predict the pore pressure before drilling into a formation.

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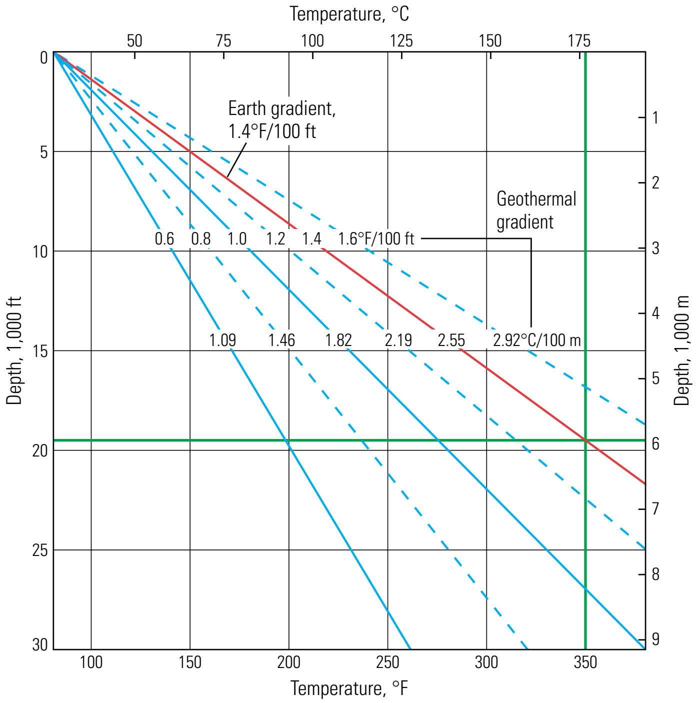


Figure 3. Earth's geothermal gradient. To reach the HPHT threshold of 350°F (vertical green line) and Earth's average geothermal gradient of 1.4°F/100 ft (red line), a well would have a depth of almost 20,000 ft [6,100 m] (horizontal green line). The thermal gradient will vary based on subsurface conditions and is not usually linear as shown.

In determining a "normal" downhole pore pressure, engineers often compute pressure using a hydrostatic gradient based on the weight of seawater. Such a well would require a depth of more than 10,700 m [35,000 ft] to reach the 15,000 psi HPHT threshold. However, because of geologic features and variable overburden forces, a higher hydrostatic pressure than that which the normal pressure gradient would predict is often required to overcome reservoir pore pressure. Drilling high-pressure wells using mud weights that are more than twice that of seawater is not uncommon. Overpressured formations, those having higher than normal pore pressure, can be present even at shallow depths.

Ultradeep wells being drilled today may reach depths beyond 10,700 m, and their hydrostatic pressure can exceed 207 MPa [30,000 psi]. Drilling assemblies, LWD tools, wireline logging equipment, well testing tools, completion hardware and well intervention tools are exposed to these extreme pressures. To mitigate the effects of high pressure, design engineers focus on metallurgy and sealing. Metals and alloys commonly used in the aerospace and nuclear power energy have been adopted by the oil and gas industry. However, use of these materials in oil and gas applications is often constrained by wellbore size limitations. This is especially true for deepwater wells in which some of the highest pressures are encountered—logging and drilling tools must withstand high pressure extremes and also fit into small diameter wellbores that are typical of ultradeep wells. Materials used for sealing elements must seal against extreme pressure, often under high temperature, and they may have to undergo multiple pressure cycles without failing.

The risks associated with downhole pressure are not only for the equipment used there. When completions, testing and production operations are performed with high pressure at the surface, a risk potential to personnel working with the equipment exists. To manage this risk and allow wellsite operations to be performed safely, engineers use equipment that is designed to function above the anticipated maximum pressure. The maximum pressure of the full system depends on the lowest rated component in the full containment string. To ensure that properly rated equipment is used, operators must know the maximum pressure potential in advance.

Pressure control requirements directly affect choices of equipment engineering and design. Pressure equipment is rated for maximum anticipated pressure, and these ratings determine material selection and thickness, elastomer configuration, sealing mechanisms and pressure control components. To ensure operations can be performed safely, the equipment is function tested above the maximum anticipated pressure prior to its use.

**Temperature Challenges**

The Earth's geothermal gradient averages about 1.4°F/100 ft [2.55°C/100 m]. At this average gradient, the 350°F threshold would require a well depth in excess of 19,700 ft [6,000 m] (Figure 3). Downhole temperatures, however, are often affected by natural conditions or external influences. Proximity to localized geothermal hotspots can quickly raise downhole temperatures encountered while drilling. At very shallow depths, steam injection used to help produce heavy oil can greatly increase downhole temperatures. Wells drilled in deep and ultradeep waters often have geothermal gradients that are lower than that of the Earth's average. Consequently, deepwater wells often have high pressure and temperatures that are below the HT threshold.

High-temperature mitigation techniques depend on the operation type as well as the equipment. Wireline and LWD tools use electronics designed for high-temperature environments. Temperature barriers such as Dewar flasks can be placed around the tool, although time constraints limit the type of operations that can be performed using flasked tools. Temperature-resistant elastomers are used for sealing elements in tools.

Tools used for LWD operations generally have lower temperature ratings than those available for wireline operations. Because drilling fluids are continuously circulated through the BHA, the tools are usually exposed to lower temperatures than are present in the formation. In extreme cases, drilling fluids may be cooled before being circulated downhole to protect sensitive BHA components.

Most HT wells are drilled using oil-base mud (OBM) systems. Special high-temperature OBM systems have been developed that retain the mud's rheologic properties at elevated temperatures. One trade-off to using OBM systems is the thermal characteristics of OBM. Wells drilled with oil-base mud systems tend to have higher downhole temperatures than do wells that are drilled with water-base mud systems and thus potentially expose downhole tools to high operating temperatures.

**Operations**

Working under HPHT conditions requires specialized equipment, proper tools and training. Advanced planning is an important aspect of successful operations; modified operational procedures must often be employed to address HPHT concerns. Whereas mistakes made in conventional wells may create routine lost time, preventing disastrous consequences to equipment and personnel from HPHT operations requires exceptional diligence. The long history of developing tools to effectively tame HPHT conditions and the experience dealing with these conditions continue to enable the oil and gas industry to push the boundaries to deeper depths and in hotter wells in the ongoing search for new sources of hydrocarbons.