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HPHT 101-What Petroleum Engineers and Geoscientists Should Know About High Pressure High Temperature Wells Environment

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Abstract

On April 20, 2010, BP's Deepwater Horizon oil rig exploded in the Gulf of Mexico. This turned out to be one of the worst environmental disasters in recent history. This high-profile blowout at the Macondo well in the Gulf of Mexico, brought the challenges and the risks of drilling into high-pressure, high-temperature (HPHT) fields increasingly into focus. New Technology, HSE regulations, new standards, such as newly recommended procedures by the American Petroleum Institute (API), and extensive training programs for the drilling crew seem to be vital in developing HPHT resources. High-pressure high-temperature fields exist in Gulf of Mexico, North Sea, Southeast Asia, Africa and the Middle East. Almost a quarter of HPHT operations worldwide are expected to happen in the American continent particularly in North America. Major oil companies have tried to identify key challenges in HPHT development and production, and several service companies have offered many insights regarding current or planned technologies to meet these challenges. However, there are so many factors that need to be addressed and learned in order to safely overcome the challenges of drilling into and producing from HPHT oil and gas wells.

Drilling into HPHT wells is a new frontier for the oil and gas industry. The growing demand for oil and gas throughout the world is driving the exploration and production industry to look for new resources. Some of these resources are located in deeper formations. According to US Minerals Management Service (MMS), over 50% of proven oil and gas reserves in the US lie below 14,000 ft. subsea. As we drill into deeper formations we will experience higher pressures and temperatures.

Drilling operations in such high pressure and high temperature environments can be very challenging. Therefore, companies are compelled to meet or exceed a vast array of technical limitations as well as environmental, health and safety standards. This paper explains the technological challenges in developing HPHT fields, deepwater drilling, completions and production considering the reports from the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly known as the Minerals Management Service (MMS). It reviews the HPHT related priorities of National Energy Technology Laboratory (NETL), operated by the US Department of Energy (DOE), and DeepStar Committees for Technology Development for Deepwater Research.

Key words: High pressure high temperature wells environment; Oil and gas industry; Gulf of Mexico

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INTRODUCTION

Projections of continued growth in hydrocarbon demand are driving the oil and gas industry to explore new or under-explored areas. As the search for petroleum becomes more extreme in terms of depths, pressures, and temperatures, companies are leading the way with innovative technologies and products for HPHT drilling. A number of innovations are in the pipeline to help companies access hydrocarbon that were once deemed too difficult to exploit. In a case of huge investments for new oil and natural gas discoveries, the oil industry has reached an agreement: no easy fields to be developed remain undiscovered, especially in offshore environments. According to Simmons, development of new approaches to drilling deep HPHT wells is required to meet engineering requirements while keeping projects economically feasible. Challenges on well drilling such as drilled extensions over 20,000ft, sub-salt drilling, very narrow drilling windows, operational challenges like lost of circulation, stuck pipe, and well control issues are even more probable when drilling in HPHT environments. The most common HPHT definition is when the pressure exceeds 10,000 psi (690 bar) and the temperature exceeds 300 °F (149 °C).

According to some studies in the near future, HPHT would be defined when the pressure if over 15,000 psi and the temperature more than 300 °F. To help identify HPHT operating environments, safe operating envelopes and technology gaps, new classifications have been developed. These classifications segment HPHT operations into main three tiers. Tier I refers to the wells with initial reservoir pressures between 10,000 psi to 20,000 psi and/or reservoir temperatures between 300 °F to 400 °F. To date, most of the HPHT operations in shale plays (GuoJiRajabovFriedheimPortella *et al*., 2012; GuoJiRajabovFriedheim & Wu, 2012; Joshi, 2012; Joshi & Lee, 2013; Rajabov *et al*., 2012) and many of the upcoming HPHT deepwater gas/ oil wells, particularly in the Gulf of Mexico, fall into Tier I . Kristin field is a well-known HPHT field in Norway with the reservoir pressure of 13200 psi and the temperature of about 350 °F. Tier II is called "Ultra" HPHT and includes any reservoir with pressures more than 20,000 and less than 30,000 psi and/ or temperatures between 400 °F to 500 °F. Several deep gas reservoirs on the US land and the Gulf of Mexico continental shelf fall into this category (Payne *et al*., 2007). Tier III encompasses "extreme" HPHT wells, with reservoir pressures from 30,000 psi to 40,000 psi and/ or temperatures between 500 °F to 600 °F. Tier III is the HPHT segment with the most significant technology gaps.

In the past HPHT (or HTHP) was attributed to any condition with pressure or temperature above the atmospheric condition. Service companies, operators, cement/drilling fluid testing equipment companies and other pipe or tools manufacturers, each, came up with a slightly different definition for HPHT condition. Most companies currently categorize their operations, products or tools into the three main tiers shown in Figure 1, however, with different pressure and temperature boundaries for each tier, Figures 2, 3, 4, 5, 6 and 7. This can be due to the fact that, for instance, a mud engineer worries more about the pressure and the temperature at which the drilling fluid might fail while a cementing engineer prioritizes when and how fast the cement sets at HPHT condition. These turning points (pressures and temperatures) are almost close but not the same. Also regulations in various geographical locations might affect this definition, for example in Norway « or » is used instead of « and » in defining a HPHT project; in other words, if either temperature or pressure meets the HPHT condition (10,000 psi or 300 °F), the project counts as a HPHT. In the UK, HPHT is formally defined as a well having an undisturbed bottom hole temperature of greater than 300 °F (149 °C) and a pore pressure of at least 0.8 psi/ft (≃15.3 lbm/gal) or requiring a BOP with a rating in excess of 10,000 psi [68.95 MPa]. Although the term was coined relatively recently wells meeting the definition drilled and completed around the world for decades (Schlumberger, 2012). In North Sea some projects are still considered HPHT with the temperatures over 250 °F.

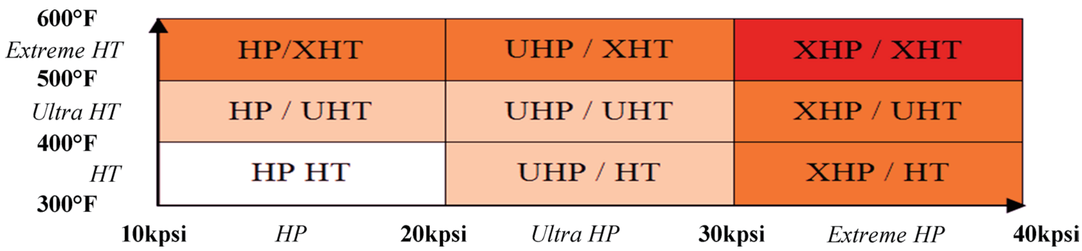


Figure 1
Matrix of High Pressure High Temperature Operation

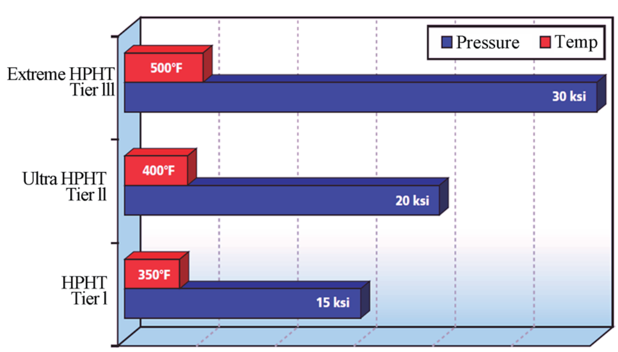


Figure 2
HPHT Tiers, Courtesy of Baker Hughes 2005

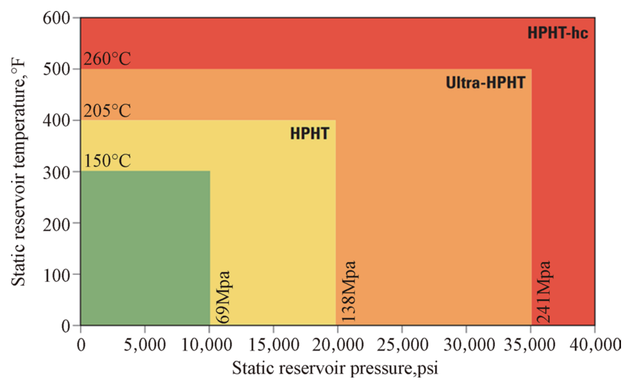


Figure 3
HPHT Tiers, Courtesy of Schlumberger, 2008

	Borehole Temperature	Borehole Pressure
HP/HT	>300°F（150℃）-350°F（175℃）	>10,000 psi（69 MPa）-15,000 psi（103 MPa）
Extreme HP/HT	>350°F（175℃）-400°F（200℃）	>15,000 psi（103 MPa）-20,000 psi（138 MPa）
Ultra HP/HT	>400°F（200℃）and above	>20,000 psi（138 MPa）and above

Figure 4
HPHT Tiers, Courtesy of Halliburton, 2012

The first 20,000 psi wellhead system was developed in 1972, which was followed quickly with the development of the first 30,000 psi wellhead system in 1974. These developments were in response to discovery of the Thomasville field in Mississippi, USA, in 1969. In addition to Thomasville and Piney Woods fields in Mississippi, other substantial HPHT developments include Central Graben fields in the North Sea and the Tuscaloosa fields with pressure and temperature of 16,000 psi and 380 °F in Louisiana, USA. Relative to the deepwater operations, well pressures may approach 15,000 psi at the mudline, and, hence, 20,000 psi subsea equipment is being pursued. Relative to the deep gas wells on the Outer Continental Shelf (OCS), 20,000 psi surface wellheads and trees, such as those used in Mississippi, Louisiana, and elsewhere, will be needed, and currently discussions are active on 25,000-psi equipment (Payne, 2010), Figures 8 and 9, Table 1.

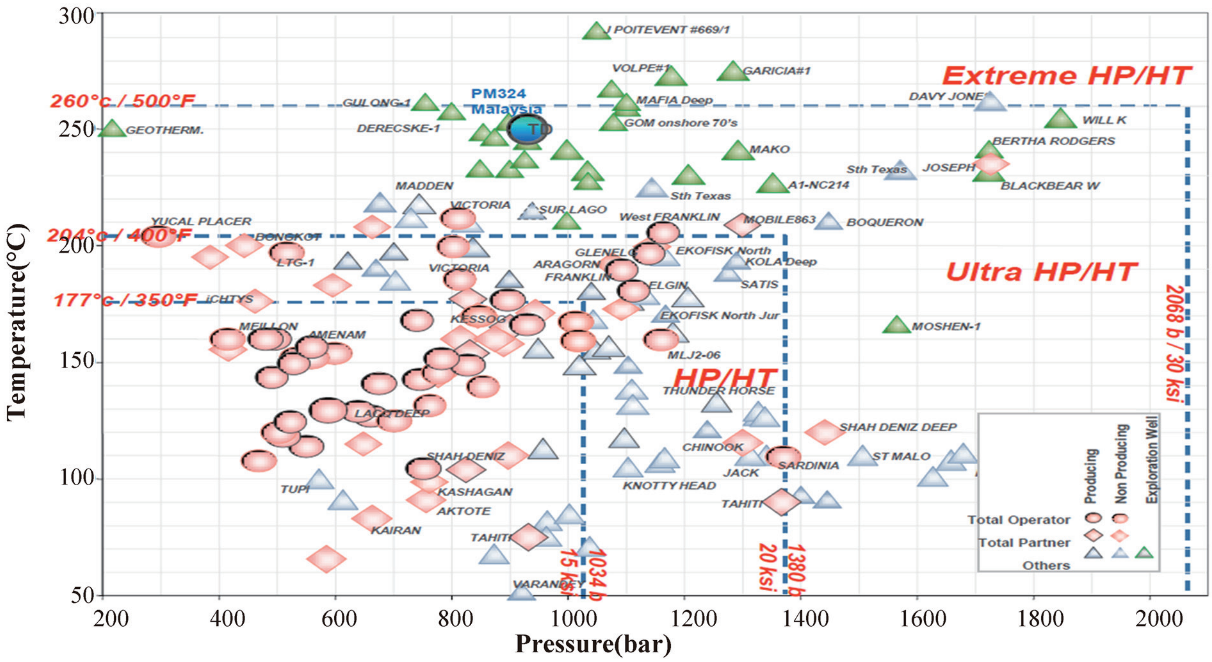


Figure 5
HPHT Tiers, Courtesy of Total, 2012

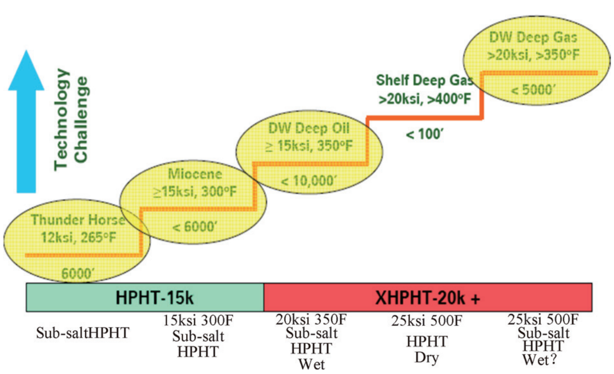


Figure 6
HPHT Tiers, Courtesy of BP

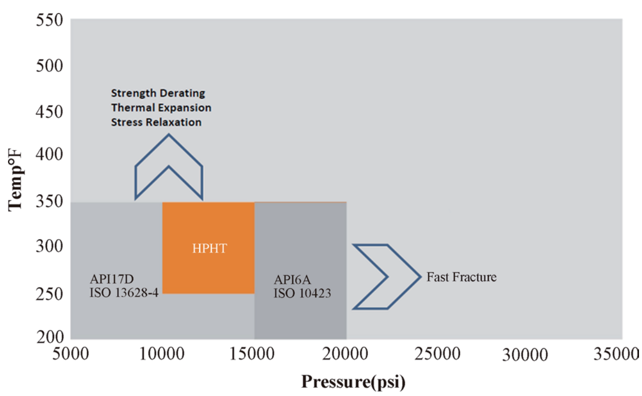


Figure 7
Subsea HPHT Range, 10-15Kpsi/ 250-350°F
Surface HPHT Range, 10-20Kpsi/ 250-350°F
(Maldonado *et al*., 2006)

The Gulf of Mexico (GOM) currently supplies more than a quarter of the America's oil production, and the Central and Western GOM remain the two offshore areas of highest resource potential and industry interest. Under customary international law, as reflected in the Law of the Sea Convention, every coastal country automatically has a continental shelf out to 200 nautical miles from its coastline (or to a maritime boundary with another country). In some cases, a country can have a continental shelf beyond 200 nm , which has come to be called "extended continental shelf" (ECS). In this maritime zone, the country may exercise sovereign rights over the natural resources including oil and gas. The legal definition of "continental shelf" is different from the traditional geologic definition. Primary studies have indicated that the U.S. Extended Continental Shelf (ECS) likely totals at least one million square kilometers an area about twice the size of California. As additional data are collected and existing data analyzed, it is becoming more clear to the extent of the U.S. ECS. To make more than 75% of undiscovered resources available, the 2012-2017 program has been proposed. This program, approved on August 27, 2012, must to the maximum extent practicable, strike a balance between the potentials for discovery of oil and gas, environmental damage, and adverse impacts on the coastal zone. It is also consistent with the President Obama Administration's *Blueprint for a Secure Energy Future,* which aims to promote domestic energy security and reduce oil imports by a third by 2025 through a comprehensive national energy policy in the US. In the near future, there would several more cases of HPHT operations in US ECS and deepwater GOM and therefore major companies will focus more on drilling and production opportunities in such areas while considering the environmental regulations, (Defining the Limits of the U.S. Continental Shelf, 2012; U.S. Department of the Interior Bureau of Ocean Energy Management, 2011), Figures 10, 11, 12 and 13.

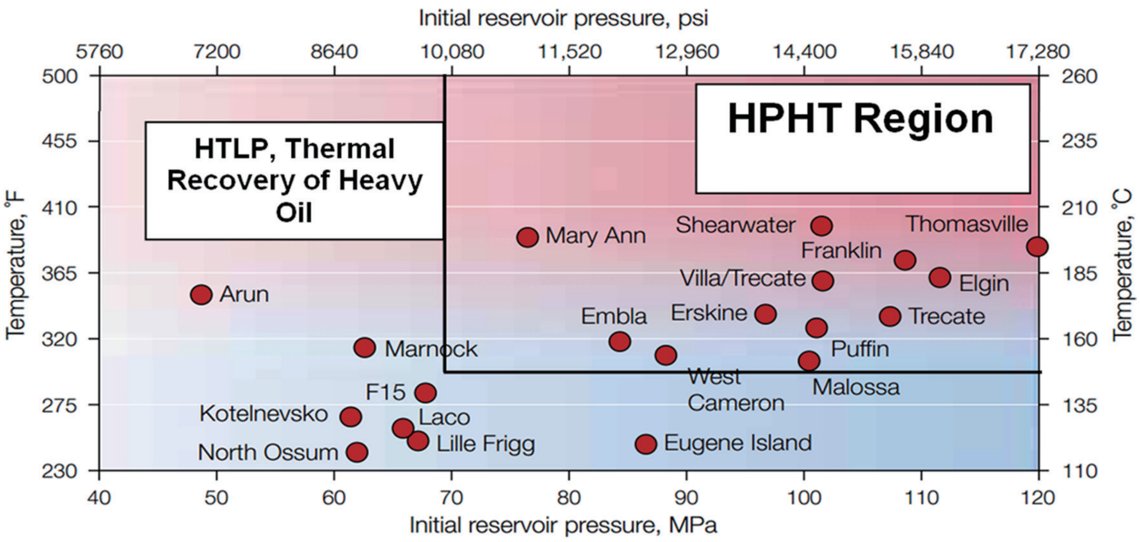


Figure 8
High Temperature Low Pressure (HTLP) Condition Occurs in the Thermal Recovery of Heavy Oil; Modified, Courtesy of Schlumberger and (Hosseini *et al*., 2011)

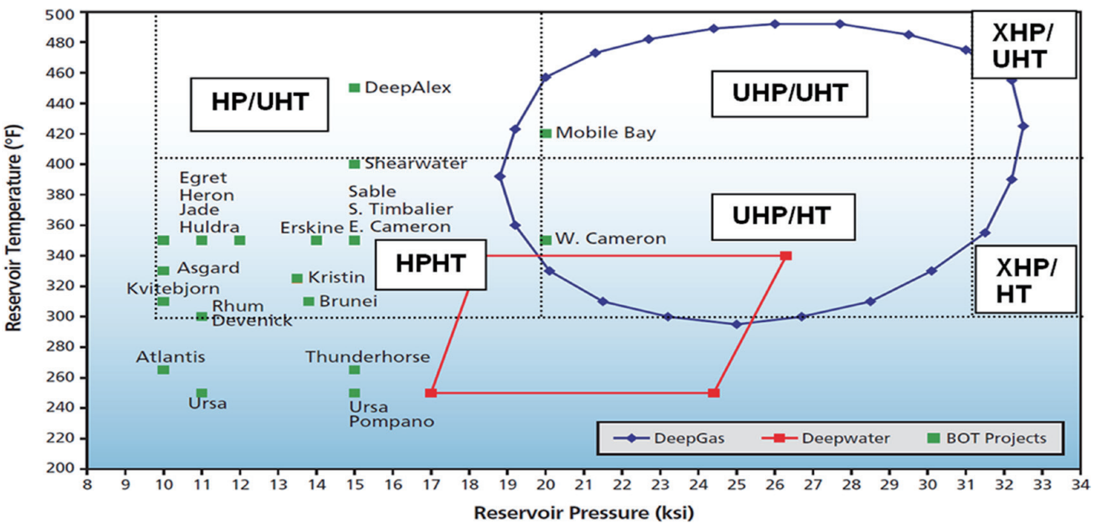


Figure 9
Industry Growth Areas Such as Deepwater Oil and Gas and Deepwater Shelf Gas; Modified, Courtesy of Baker Oil Tools

Table1
Some of the Deep Gas Cases in Gulf of Mexico

Year	Operator	Well Name	TVD (ft)	Location
2003	Shell	Shark	25,745	South Timbalier
2005	Chevron	Cadilac	24,795	Viosca Knoll
2005	Shell	Joseph	25,537	High Island 10
2006	ExxonMobil	Blackbeard	30,067	South Timbalier
2008	McMoran	Blackbeard RE	32,997	South Timbalier
2009	BP	Will K	28,404	High Island
2009	McMoran	Ammazzo	25,488	South Marsh Island
2009	McMoran	Davy Jones	29,300	South Marsh Island
2010	Armstrong O&G	BP Fee	15,800<	Cameron Parish
2010	McMoran	Blackbeard East	32,000<	South Timbalier
2011	McMoran	Davy Jones Offset	30,700<	South Marsh Island
2011	McMoran	Lafitte Project	23,000<	Eugine Island

HPHT wells are usually located in deep-water so the cost will be greater because the cost of rig rental is usually responsible for about 70% of well total costs in offshore environments and trip times increase resulting from the great depths. According to Falcón (2007), the average drilling time of HPHT wells is 30% longer because ROPs are very indolent through the highly compacted formations. Additionally, ROP in HPHT wells is usually 10% of normal drilling conditions. (Radwan and Karimi, 2011). The Elgin–Franklin fields are two adjacent gas fields located on the UK Continental Shelf (UKCS) and in the Central Graben Area of the North Sea 240 kilometers (130 nmi) east of Aberdeen at the water depth of 305 ft.

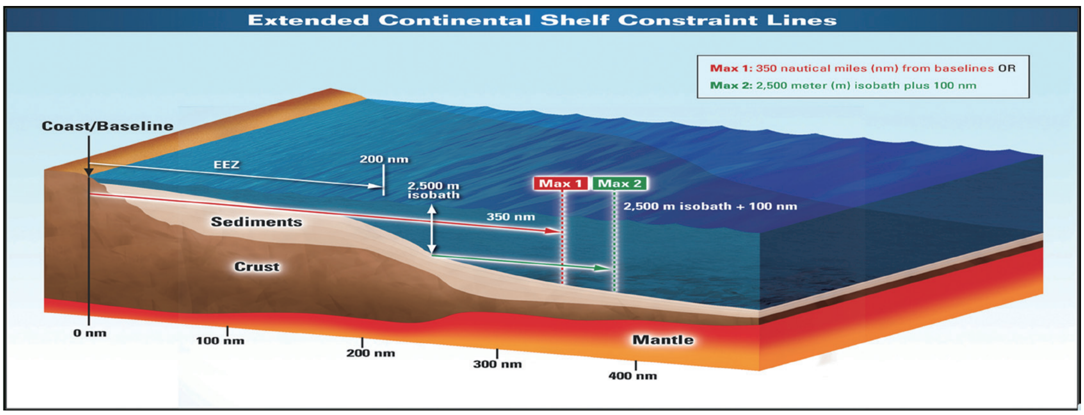


Figure 10
Constraint Lines Used for Defining the Extended Continental Shelf Under Article 76 of the Law of the Sea Convention

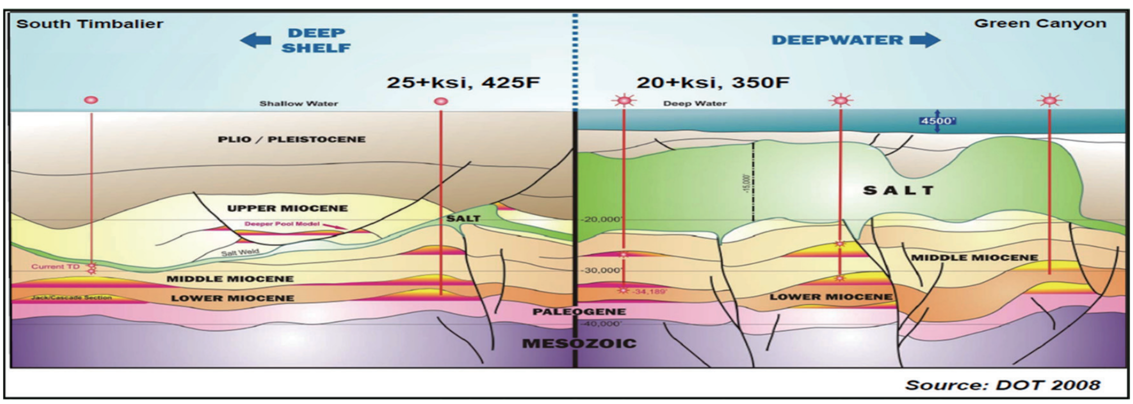


Figure 11
Deep Shelf vs. Deepwater, Gulf of Mexico

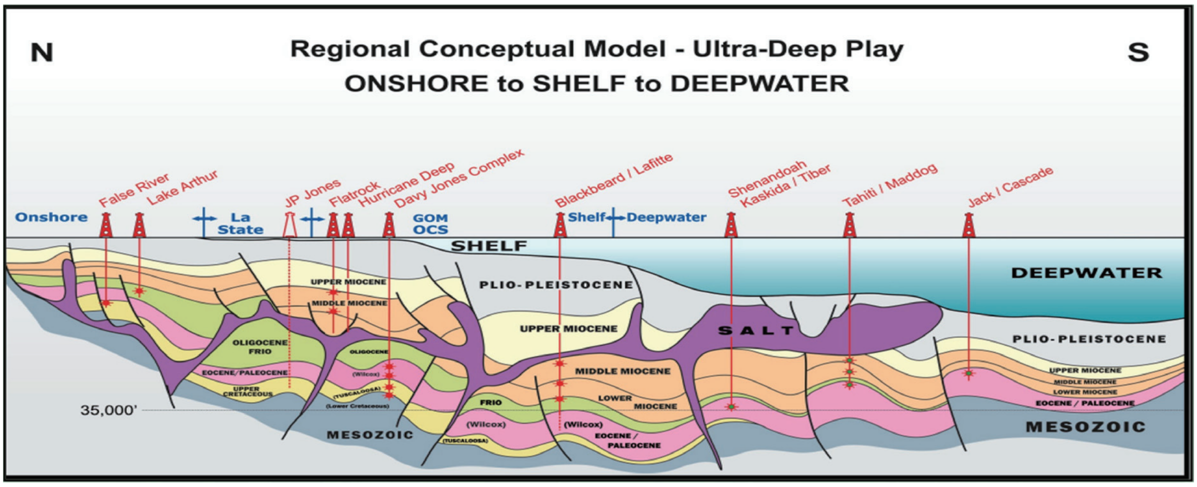
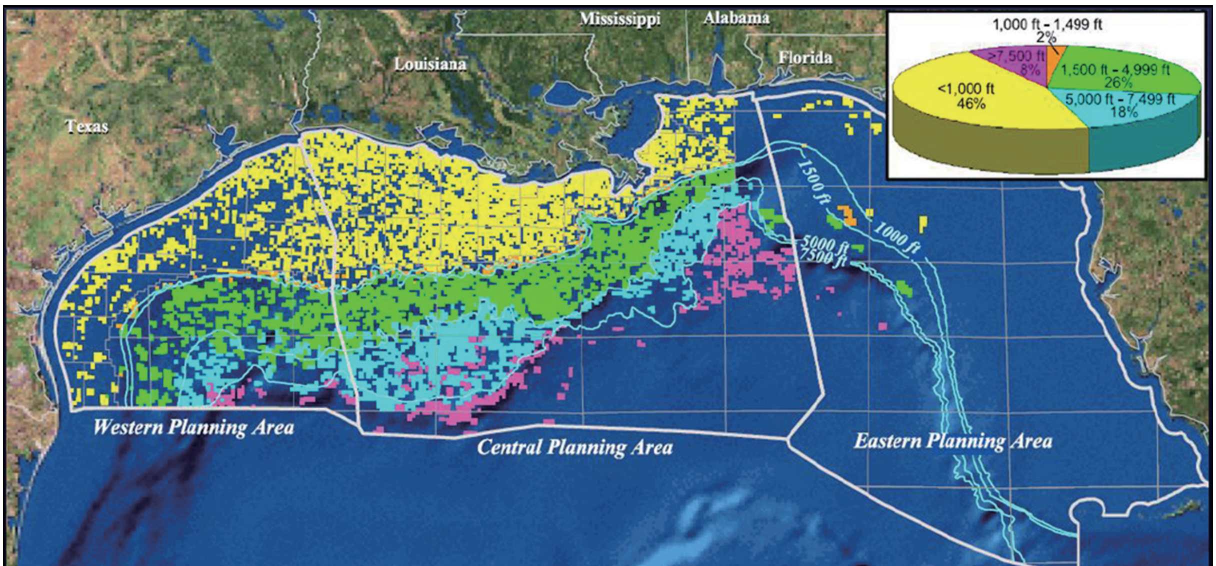


Figure 12
Gulf of Mexico, Onshore, Shelf and Deepwater Plays



6,522	Total active GoM leases	
150	active leases	1,000—1,499 ft water depth
1,800	active leases	1,500—4,999 ft water depth
1,500	active leases	5,000—7,499 ft water depth
750	active leases	>7, 500 ft water depth

Figure 13
Operators' Lease Position, GOM (Larson, 2011)

Elgin–Franklin fields have the reservoir temperature of 387 °F and pressure of 16,750 psi. West Franklin is among the HPHT environments in the world (Tier I), Figure 14. In addition to that, the West Franklin reservoir is being depleted which increases the overall development complexity. Numerous technical challenges such as casing collapse, accelerated jacket, riser and pipeline design and design of the Elgin WHP B required permanent out of the box thinking when the opportunities were realized. Morvin is also another subsea HPHT field located in the Haltenbanken area, on the Norwegian Continental Shelve with the initial reservoir pressures and temperatures are up to 12154 psi (838 bar) and 333 °F (167 °C).

Figure 14
Elgin Field, North Sea

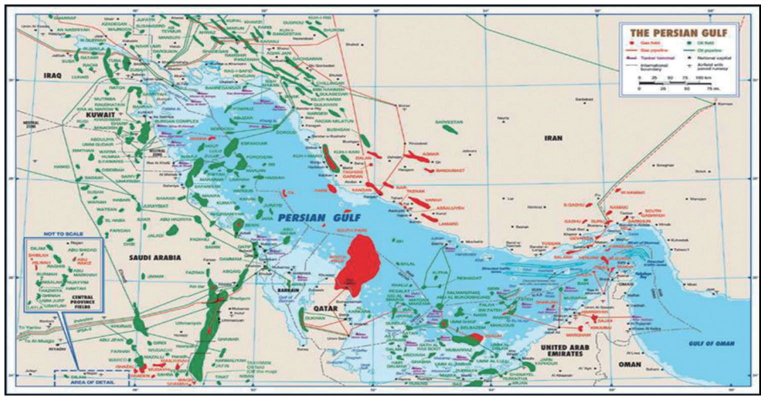


Figure 15
Perisan Gulf, Middle East

The top 5 future oil fields in the world all reside in the Middle East. Offshore the Persian Gulf and Abu Dhabi has the Khuff formation, characterized as a high flow rate gas reservoir with HPHT and the presence of both H_2S and CO_2. Wells in this region are often multi-zonal completions, Figure 15. The Mansuri petroleum oil field located in the Dezful embayment consisted of three reservoirs: Asmari, Bangestan and Khami. Khami with 330 °F and 12700 psi falls into the HPHT operation category in Middle East. The Khami group is divided into 11 zones and the sub zones 1 and 3 in zones 5 and 10 are the best reservoir zones.

The Permian carbonate unit known as the "Khuff Formation" in the Persian Gulf region occurs in Bahrain, Qatar, Abu Dhabi, and Saudi Arabia. In south-southwest Iran and the coastal provinces, the thick carbonates, were formerly known as the Khuff Formation, are now known as the Dalan Formation. The Permian Dalan and Khuff Formations constitute very extensive gas reservoirs in the Greater Persian Gulf area. In Kuwait, deepening KM 3 well in Sudair formation was done by mud weights as high as 19 ppg, Figures 16 and 17. The Khuff formation was deposited during a regional transgression over a stable shelf of very low relief which had a minor clastic supply on the margin of the Arabian Peninsula, the world's largest peninsula. However, in Oman the Khuff formation changes into a continental red-beds facies (Kashfi, 1992).

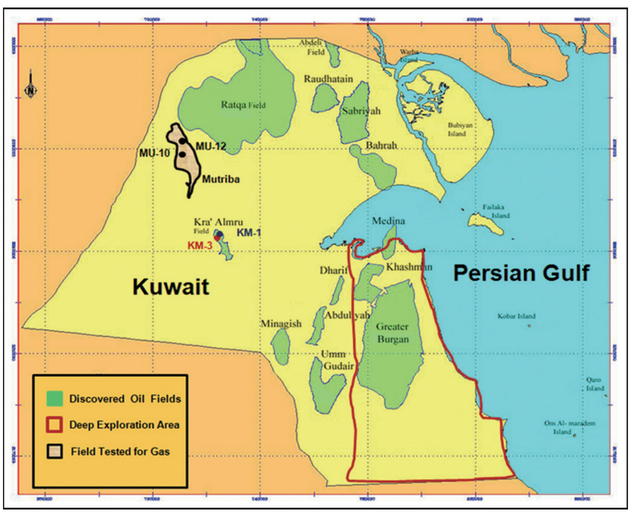


Figure 16
Deep Exploration Wells, Kuwait, Middle East

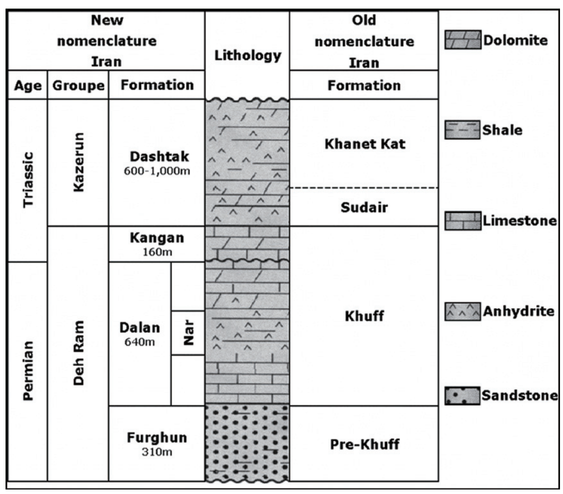


Figure 17
Stratigraphic Nomenclature (Permian-Triassic Rocks of Iran)

An exploration well will be drilled between 2012 to 2014 on the Maja licence in the Danish North Sea after the Danish Energy Agency (DEA) granted it a two-year extension to two licences in the region. This well targets a High Pressure High Temperature (HPHT) prospect in the licence. Danish North Sea HPHT wells typically cost about $100 million because of the specialised equipment and the time necessary to drill in these technically challenging conditions (Maersk Oil, 2012), Figure 18. Other example in South America was to test Belmonte 2, a well in deepwater offshore brazil located at block BM-S-4. Temperature and pressure was reported as approximately 300 °F and 13000 psi(Bottazzi Franco, 2007), Figure 19.

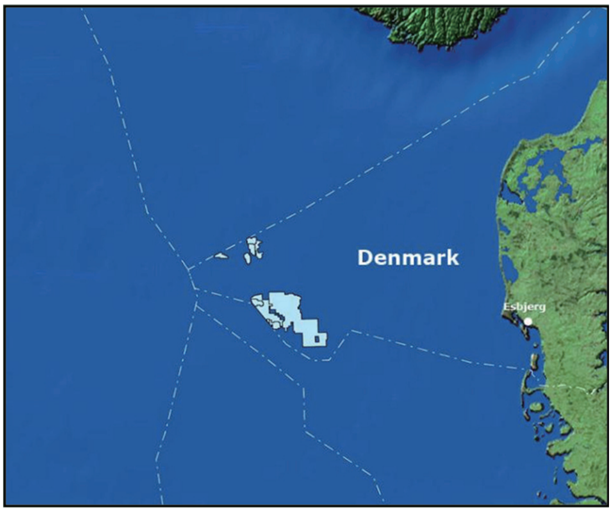


Figure 18
Maja Licence in the Danish North Sea

Figure 19
Belmonte 2, Deep Water Block BM-S-4 ,Brazil

1. TAXONOMY OF TECHNOLOGY GAPS

(1) ***Physical technology gaps***. Whether or not it is possible to actually conduct particular operations and employ particular methods in pursuit of a geological objective in drilling and completing a well.

(2) ***Economic technology gaps***. Whether or not a particular operation is worth the cost of conducting the operation or applying the method.

(3) ***Regulatory technology gaps***. These concern whether it is permissible to conduct (or not conduct) certain operations and employ (or not employ) particular methods while drilling and completing wells(Proehl, 2006).

In the case of the Montara well blowout in 2009 and oil spill in the Gulf of Mexico in 2010, one of the main contributing factors to failure of the well in both cases, was a substandard cement job. In 2010, "cement design" was picked as a top HPHT technology gap in the HPHT well summit in London, however in a same event in 2012, it was placed as the third most concerning technology gap in the HPHT arena, behind safety, testing and seals, Figures 20 and 21. Amongst the issues that are prevalent in HPHT well development, the one that stands out is the lack of properly-trained and experienced staff to fill the ever expanding portfolio of global HPHT ventures (Annual HPHT Wells Summits, UK. 2010 & 2012). Framed in the general context of the upcoming great crew change, this is a challenge that will doubtlessly get more serious in its gravity as time goes by, particularly as the two areas that will be experiencing the largest growth in HPHT operations are drawing upon pools of talent will unfavorable demographics, Figures 22, 23 and 24.

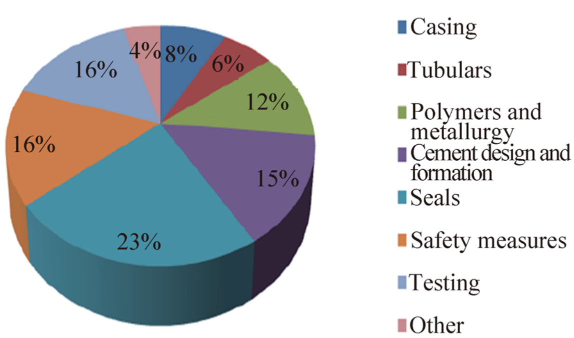


Figure 20
HPHT Technology Gaps, 2012

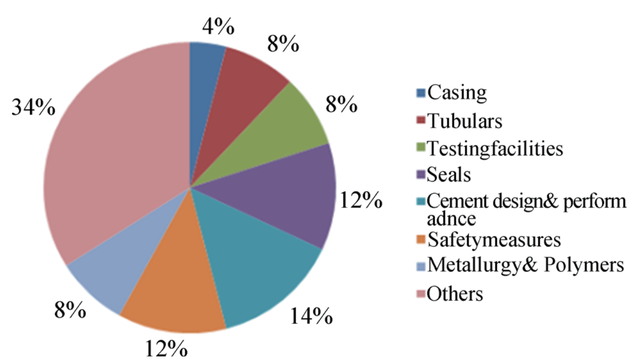


Figure 21
HPHT Technology Gaps, 2010

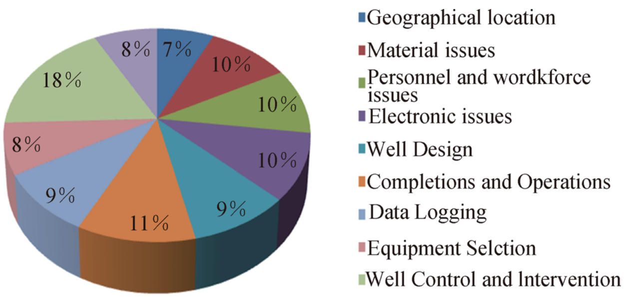


Figure 22
Most Challenging Issues for Operators in Developing HPHT Wells

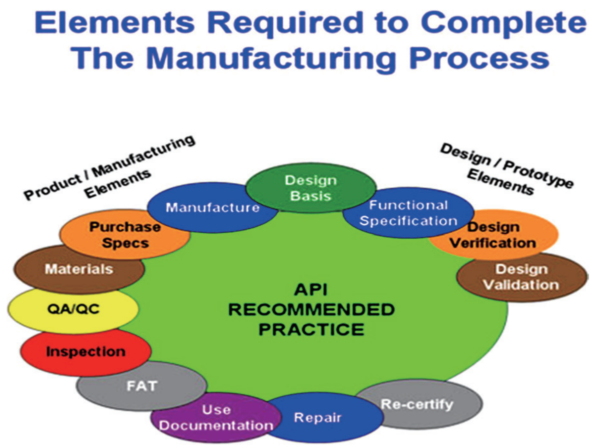


Figure 23
API Maps out a Process for the Design Verification and Design Validation, API PER15K HPHT Report

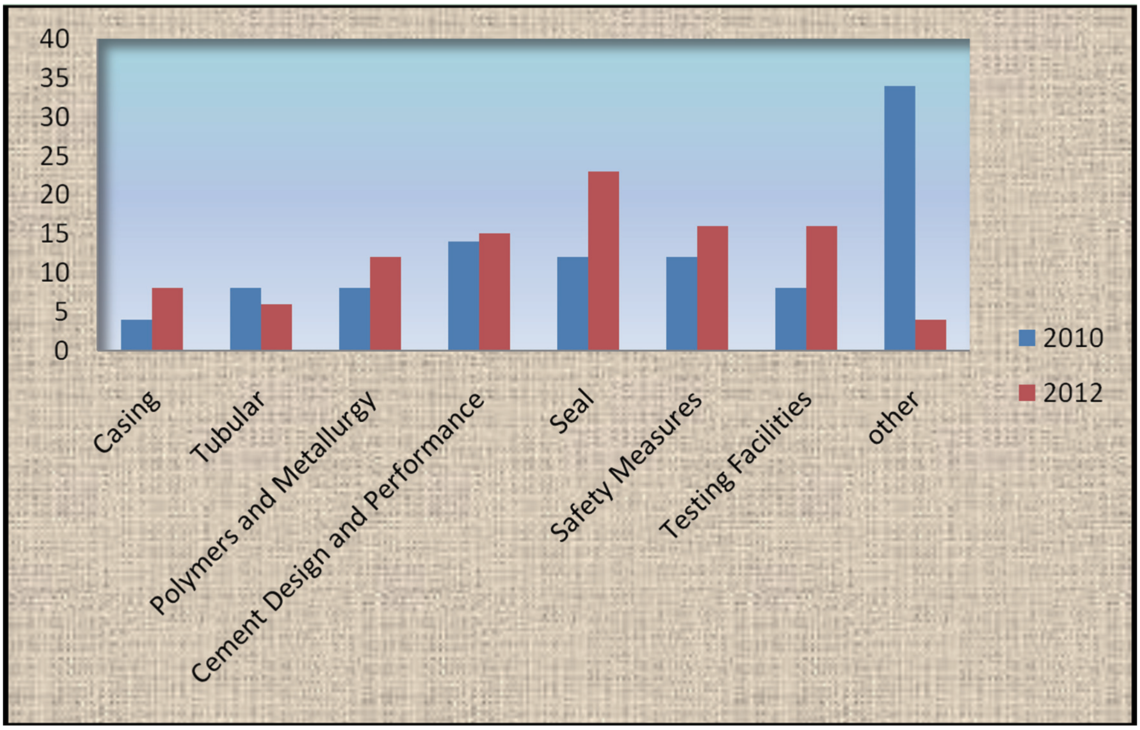


Figure 24
HPHT Gaps Transition from 2010 to 2012

2. HPHT DRILLING CHALLENGES

Technical concepts in HPHT drilling are significant to design the tools for the key planning processes. Formation pressure prediction, fracture pressure determination, casing setting depth, drilling fluid's rheological properties, hydraulics, bit selection and cementing program should be all highlighted more carefully when drilling into HPHT environment. Also some drilling methods such as casing-while-drilling and managed pressure drilling could considerably decrease the non-productive time (NPT) and lead to a safer drilling operation. Issues listed below represent primary concerns of drillers planning HPHT deep wells. As the state of the art drilling technology advances, additional concerns will surface that merit evaluation (Proehl, 2006) (Figure 25).

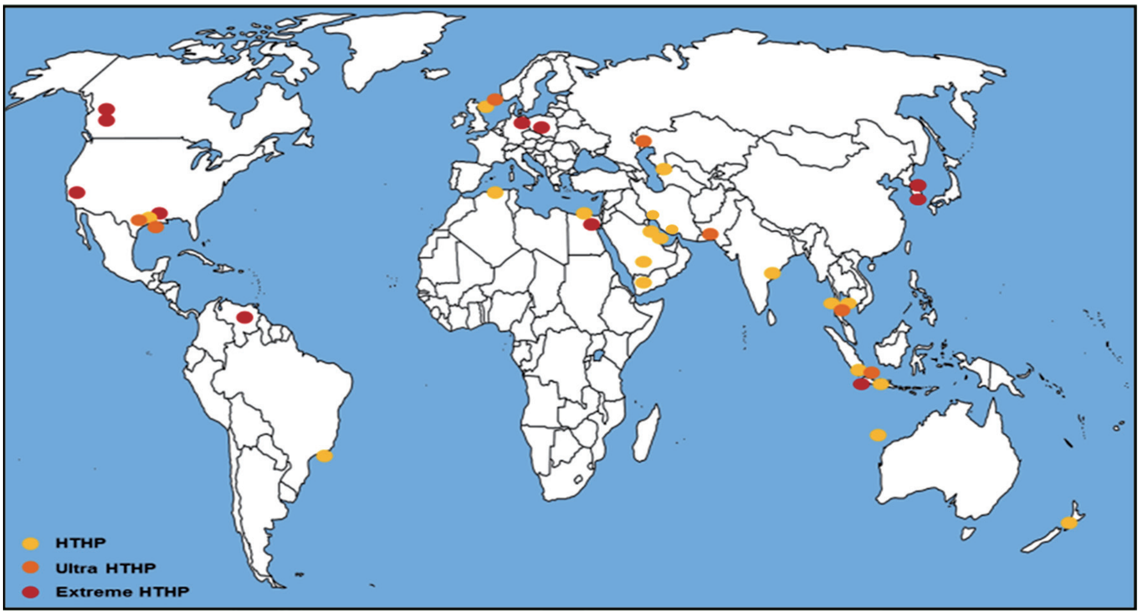


Figure 25
Locations of High-Temperature High-Pressure Operations Around the Globe

(1) Limited Evaluation Capabilities

- Most tools work to 425 °F on wireline; very limited tool availability from 425 °F to 450 °F on wireline.
- Battery technology works to 400 °F (mercury) for MWD applications.
- Sensor accuracy decreases with increasing temperature.
- LWD/MWD tools are reliable to 275 °F with a clear decrease in dependability to 350 °F.

(2) Low ROP in Producing Zone

- Bits typically remove 10% of the rock per bit rotation in this environment compared to normal drilling conditions for Gulf of Mexico wells.
- Crystalline structure breaks down in PDC bits at these conditions. (Boron expansion is an issue.)
- Roller-cone bits are unsuitable for this environment.
- Impregnated cutter drilling is often slow.
- Improvements in turbines and motor design have enhanced ROP by increasing rpm.
- Torque is the main issue, although work on sealless Moyno pumps offers high torque solutions.
- Optimizing bit, motor, mud and drill string dynamics as a system offers possibilities to improve reliability and penetration rates.

(3) Well Control

- The drilling window is very small and it can cause potential well control problems.
- Drilling Fluid Loss is an issue due to lithology and geopressure.
- Mud storage due Hole Balooning.
- Solubility of methane and H_2S (hydrogen sulfide) in oil-base mud.
- Current well head design is 15,000 psi and 350 °F. There is a work in progress for 20,000 psi, 350 °F equipment . Wellhead design for 25,000 psi, 450 °F is needed.

The fingerprinting overall objective is to identify a real influx in a quick and correct way, comparing real time data to previously obtained information. Data recorded during a certain operation provide the “expected behavior” or, simply, fingerprinting. Clear communication between the driller, the mud logging team and the well pressure-measurements equipments operator is fundamental for obtaining precise results. Pressure, temperature and tank volumes change continuously even after the pumps are shut down. The drilling team usually makes use of a “decision tree”, that depending on the sequence of occurred events during the well shut in and on the records of annular pressures and surface pressures, it is possible to identify if the event is a kick or any other such as ballooning effect or breathing formation.

(4) Non-Productive Time

- Stuck pipe and twisting off
- Trip Time – caused by tool failure (LWD/MWD) and bit trips
- Decision making caused by lack of ultra and extreme HPHT experience, the “learning curve”
- Safety issues associated with handling drilling fluids and drill strings at HT condition.
- Conventional circulation drilling causing well control or damaging drilling components. Continuous circulation drilling provides more hydraulic stability in HPHT/MPD or

UBD operation (L.J.Ayling *et al*., 2002; ShadravanKhodadadian *et al*., 2009; ShadravanNabaei *et al*., 2009).

(5) Drilling Fluid

- Serve as a coolant for LWD/MWD
- Improve ECD control and reduce friction pressure.
- Drilling Fluid Loss.
- Static /Dynamic Barite Sag

Basically, drilling fluids may be classified in liquids, gases and gas-liquid mixtures. Liquids are the most utilized and may be grouped in water based mud (WBM) and oil based mud (OBM). In directional wells and under high temperature and pressure, the OBM is more effective than the WBM, due to its thermal stability and lubricant characteristics. Because of the environmental awareness the OBM's evolved from conventional oils, such as the diesel, to synthetic oils. Static and/or dynamic barite sag is a common problem in HPHT wells. This phenomenon results from loss of circulation, torque and drag, ECD fluctuations and other operations that require the mud to stay static for a significantly long time. So far, the solutions presented to eliminate this phenomenon require adding unconventional mud additives instead of barite [i.e., micromax weighting particles like Manganese Tetraoxide fumes (Mn_3O_4) and/or Ilmenite ($FeTiO_3$) and/or combining clay-free OBM and synthetic with MMT weighting agent(Elkatatny *et al*., 2012) .

"Circulating mud behaves as a countercurrent heat exchanger. The rate of heat exchange between the mud, the casings and the formation at any particular depth depends on the temperature, thermal conductivity and specific heat capacity of the materials and on the velocity of the mud. In the presence of casing, vertical conduction of heat further complicates the temperature distribution.

In the absence of enough circulation, gravity may cause weighting material (e.g. barite) to fall, resulting in density segregation or sagging (a). In deviated wells, sagging may result in a barite bed on the low side of the hole (b). Depending on the angle of the wellbore and the strength of the bed, the barite beds can slump down the low side of wellbores like an avalanche (c). The movement of the solids in the drilling fluid during sagging may result in a lowering of the viscosity by shear thinning, accelerating the process. Ultimately, slumping may result in barite accumulation and a pronounced density change within the drilling fluid (d)" (Schlumberger, 1998), Figures 26, 27 and 28.

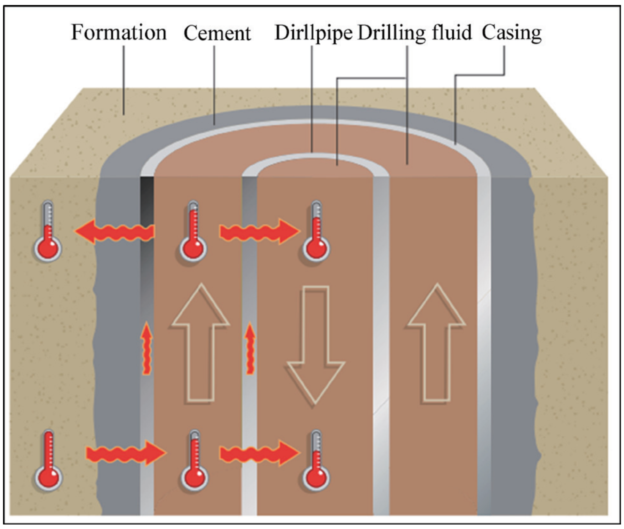


Figure 26
Heat Transfer in the Wellbore, Schlumberger 1998

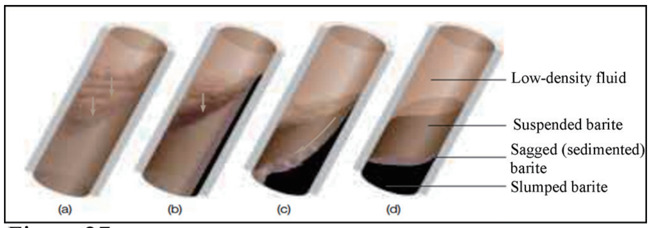


Figure 27
Barite Sag Affected by Fluid Properties,Schlumberger1998

Figure 28
Drilling Fluid Should Withstand the HPHT Condition

A new type of surfactant has been studied for enhanced oil recovery. However, surfactant can be used for oil/water emulsions drilling fluid. The rheological and filtration loss characteristics of colloidal gas Aphron and also rheological properties of heavy asphaltic petroleum fluids have been investigated (Alfi *et al*., 2012a, 2012b; Nareh'ei *et al*., 2012; ShahriTehrani *et al*., 2011; Shahri & Zabihi, 2012; ShahriZeyghami *et al*., 2011).

Shadravan, Amani, Beck, Schubert, Zigmond and Ravi have done series of HPHT testing on OBM and WBM by the extreme HPHT Rheometer, Chandler 7600, focusing on the HPHT fields in the US and in Qatar (e.g. Khuff). Lee, Shadravan and Young evaluated the performance of various HPHT Rheometers, modeled the rheological properties of a novel HPHT OBM and delivered some comments to the API committee (Al-yami & Schubert, 2012; Amani, 2012; Amani, M. & Al-Jubouri, M., 2012; Amani, M. & Al-jubouri, M.J., 2012; Lee *et al*., 2012). Desirable properties of the drilling fluid at HPHT condition is summarized in Table 2.

Since most of the HPHT Rheometers rely on an ideal "frictionless" pivot and jewel design to provide the readings, the ideal condition may not be met especially when the test can be affected by quite a few factors including temperature, pressure, solids content, type of solids and time of usage. This certainly can impact the quality of the data generated under the maximum capacity of the instrument, Figure 29. This difference can be due to different mechanical designs. Stamatakis *et al*. reviewed the HPHT drilling fluids challenges and investigated a new fluid system designed for such HPHT environments.

Wang and Zhao studied the high density water-based and also oil based drilling fluids for deep wells. Mixing of confining fluid and test sample has been a controversial issue for some time, although different cell designs have been used to minimize the mingling of the two fluids. Also proper fluid composition and product chemistry is required to ensure sufficient thermal stability of the test fluid under extreme-HPHT conditions. The development of suitable products for extreme-HPHT formulation would require more efforts and resources than just running the extreme-HPHT test. Without proper thermal stability, simulation using properties obtained at lower temperature and pressure will not be reliable. (Lee *et al*., 2012).

Table 2
The Desired Properties of the Drilling Fluid for Optimum Performance at HPHT Condition

Drilling Fluid Properties	Required Performance in HPHT Wells
Plastic Viscosity	As low as reasonably possible to minimize ECD
Yield Stress and Gel	Sufficient to prevent sag, but so high as cause gelation, or high surge and swab pressures
HPHT Fluid Loss	As low as reasonably possible to prevent formation damage and risk of differential sticking
HPHT Rheology	Stable and predictable to control sag , gelation and ECD
Compressibility	Must be known to estimate downhole pressures and ECD
Stability to Contaminants	Stable in presence of gas, brine and cement
Gas Solubility	Needed for accurate kick detection and modeling
Stability to Aging	Properties do not change over time under either static and dynamic conditions but in reality properties slightly, drop after dynamic aging and increase after static aging.
Solid Tolerance	Properties insensitive to drilling solids
Weighting	Must be able to weighted up rapidly if a kick is taken

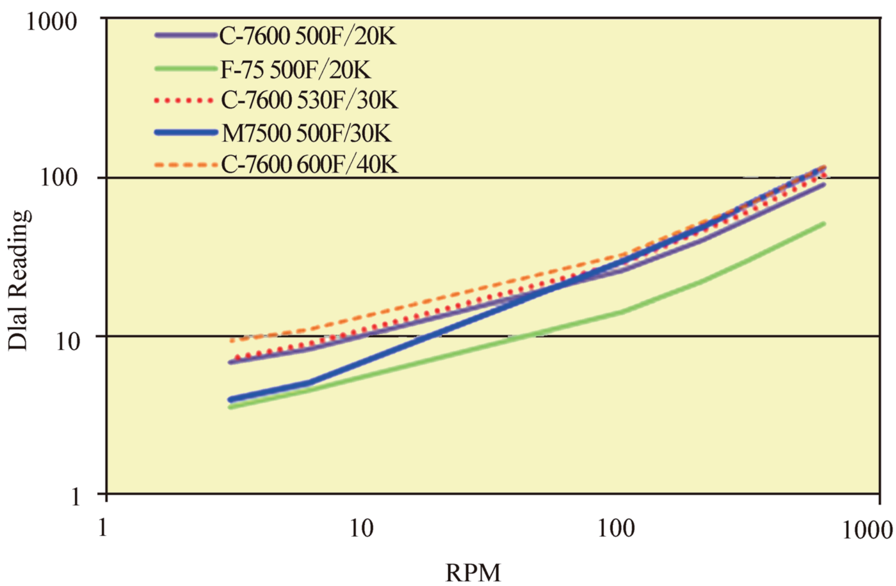


Figure 29
A Comparison of the Rheological Profiles of the extreme HPHT Invert Drilling Fluid Measured by HPHT Viscometers at their Maximum Capacity, Courtesy of M-I SWACO and Texas A&M, 2012

The hydraulics planning and fluid design process is very dependent on establishing how pressure and temperature conditions in the wellbore affect the fluid rheology. Any calculation that ignores these effects is bound to give erroneous results and course correction along with its associated costs may be required during later stages of drilling. Any drilling fluid must be designed with the primary objective of maintaining its design properties throughout the wellbore. The drilling fluid rheological properties not only decide the ability of the fluid to carry cuttings but also the magnitude of the frictional pressure drop that occurs as it is circulated through the system. This frictional pressure drop, apart from determining the pump pressures required to maintain circulation also determines the increase in pressure at the bottom of the well bore during circulation (ECD).

In drilling operations involving narrow operating windows (pore pressures and fracture pressures very close to each other, something commonly experienced in deep HPHT wells) prediction and control of ECD is a must to prevent formation fracture and lost circulation, which may result in well control and wellbore stability issues. The fluid rheology is also influenced by temperature and pressure. In fact, the degree of this influence is more difficult to predict than in the case of density. Changes in the rheological properties of the fluid impact the equivalent circulating density during circulation and also the hole cleaning capacity. For example a fluid might have sufficient viscosity to lift cuttings to the surface at normal conditions but it becomes too thin at down hole conditions therefore causes severe hole cleaning issues due to the drilled solids dropping off from the fluid and packing of at the bit. These problems are amplified in deviated holes where hole cleaning related problems can result in expensive and time consuming side-tracking operations or even lead to well abandonment. The need to quantify rheological changes in drilling fluids along the well bore cannot be understated. Zamora (2012) measured the volumetric behavior under extreme temperatures and pressures of a broad range of the oils, synthetics, and brines currently used in industry to prepare oil, synthetic, and water-based drilling fluids(Zamora & Roy, 2000; Zamora *et al*., 2012) Table 3.

Table 3
Summary of HPHT Challenges in Drilling, Modified (Proehl, 2006)

HPHT Gaps	Pressure (psi)	Temperature (°F)	Issues	Opportunities
Drilling Fluids OBM WBM SBM	40,000 30,000 30,000	600 500 500	Gas/ H2S solubility in OBM Friction pressure contributes to losses Mud cooling is beneficial	Reduce H2S and methane sol. in OBM Reduce friction Improve cooling
Wellheads & Casing Hanger	15,000	350	20k psi, 350°F system will be developed. 25k psi system requires a totally new design.	Improve sealing technology. Amend API specs. Metal-to-metal sealing required for 25k psi.
Directional Drilling Motors Control/Steering Long Sections	25,000	425	Torque is the issue. Lack of torque causes motors to stall. Motor seals are an issue at high temps.	Improve turbines - Higher RPM and higher torque motors. Motor rated to higher operating temp
LWD / MWD High Reliability Limit	35,000* 20,000 30,000	390* 275 500	Developed by NETL* Exponential decrease in reliability from 275°F to 350°F. Calibration shifts at higher temperatures. Batteries have a 400°F limitation. Vibration reduces reliability. Telemetry is relatively slow.	Improve batteries (500°F). High temp electronics. Reduce work string vibration. Improve sealing. Real-time telemetry. H2S and gas sensors.
Openhole Logging All tools Limited Tools	25,000 25,000	350 450	Limited tool availability at higher temps. Calibration shifts at higher temperatures.	Extend range to 500°F. Develop more tools for 500°F service. Consider fiber optics.
Bits PDC & TSP Roller Cone Not Desirable	30,000	500	Penetration rate is low. 10% of normal ROP.	Take a Systems Approach. Bits, Motors, Mud, Drill String. Continue work on cutters.
Rheometers	40,000 30,000 30,000 20,000 2,500	600 600 500 500 500	Lack of precision for low shear rates. Slightly different dial readings at same pressure and temperature (esp. at HPHT condition) as the result of different mechanical instruments designs.	Improve a compatible API procedure for the HPHT Rheology Testing.

3. CESIUM FORMATE

Cesium formate is a particle free brine system. The main advantages of such a drilling fluid are low ECD values and quick kick detection. However, fluid loss is considered as its disadvantage in some cases (e.g. Kristin Field) 10 times more than a typical oil based fluid. Also Cesium formate is very expensive. After the experiences with Cesium formate mud system it became apparent that drilling high angle well would not be possible with this type of drilling fluid. For the high angle wells often an oil based mud system gets chosen but sagging issues are expected.

OBM is often used to drill challenging HPHT wells owing to its inherited thermal stability when compared to water-based drilling fluid. Most of the invert drilling fluids can handle temperatures up to 400 °F without significant issues. However, when temperature is above 400 °F, the chemicals used in the drilling fluid can become unstable and thermal degradation can occur over a short period of time resulting drastic changes in rheology and other fluid properties. Recently some new formulations have been developed that are stable up to 600 °F and 40,000 psi**,** summarizes the challenges in HPHT drilling, Figure 30.

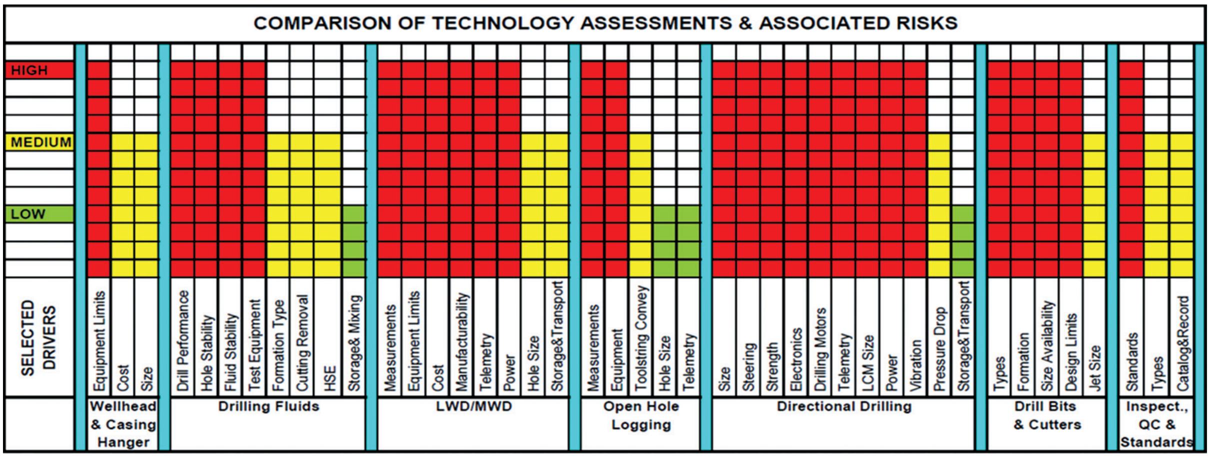


Figure 30
Significance of Bridging the HPHT Drilling Gaps (Proehl, 2006)

4. CEMENTING HPHT CHALLENGES

Well cementing operations in HPHT environment present special system challenges as the physical and chemical behavior of cement materials changes greatly because of the high pressures and temperatures. These tough conditions add many challenges not only during the well cementing operations, but also later to the set cement sheath along the well life. For instance in South Texas, the temperatures and pressures at which the cement needs to be placed can be very high, routinely exceeding bottomhole static temperatures of 420 °F and pore pressures requiring fluid densities of 18 ppg or greater to maintain well control.

These extreme conditions can present challenges not only during placement of the cement slurry in the wellbore but also later to the set cement sheath during the life of the well (Wray *et al*., 2009 ; Moe *et al*., 2003) . Cement sheath integrity is a very critical matter especially in the salt during the production phase. For instance, the challenges are mainly connected to the narrow margin between fracture and pore pressures in addition to the tight annulus in lower zones. Primary cementing is a critically important operation in construction of a well. Apart from providing structural integrity to the well, the chief purpose of the operation is to provide a continuous impermeable hydraulic seal in the annulus, preventing uncontrolled flow of reservoir fluids behind the casing. It is however ideal to assume that cementing is the only consideration for effective zonal isolation.

Cementing can be a bit complicated, depending on the region drilled and sections encountered. Therefore special attention has to be paid to cementing processes especially in HPHT wells. The secret to zonal isolation is the good bonding properties of the cement with the casing and the formation, but this can be affected by cement shrinking and stress changes induced by downhole variation of pressure and temperature. In HPHT formations, the wells are subjected to high temperature variations and these changes affect both the formation and the casings, causing expansion and contraction. This expansion and contracting of casing and plastic formation like salt causes cracks in the already set cement. The setting of cement is by the reaction between water and cement.

This process is called hydration and if it continuous, the pore pressure in the setting cement reduces with its pore spaces. The post-set cement consisting of minimal number of pore spaces when subjected to high loads in deep wells compression sets in and destroys the cement sheath by compaction of matrix porosity. This destruction of cement matrix can be said to be caused by mechanical failure or damage and they create cracks in the cement matrix. These cracks are a pathway for the migration of gas from the formation to the surface, thereby shortening the life of the well because the integrity of the cement has been compromised (Yetunde & Ogbonna, 2011) **.**

Migration of gas through the cement has been an industry problem for many years. Some studies pointed out that approximately 80% of wells in Gulf of Mexico have gas transmitted to surface through cemented casing. For twelve months or more, after cement has set, it continues to hydrate and consequently develop in strength. After this time, it maintains the strength that it has attained except if it is attacked by agents of erosion. Cement will attain maximum strength after one fortnight is exposed to temperatures exceeding 230 °F. After these first two weeks, the strength slowly starts to decrease.

This process of cement losing its strength is known as strength retrogression. Structural changes and loss of water are the agents of cement degradation. When cement is set, it contains a complex calcium silicate hydrate called tobermorite. At temperatures around 250 ^{o}F, tobermorite is converted to a weak porous structure which causes strength retrogression. The rates at which these changes occur depend upon temperature. (Ogbonna & Iseghohi, 2009)

4.1 Stabilizing of Cement Systems and Stopping of Strength Retrogression

"Strength retrogression, a phenomenon that occurs naturally with all Portland cements at temperatures of 230 to 248 °F (110 to 120 °C), is usually accompanied by a loss in impermeability, and is caused by the formation of large crystals of α-dicalcium silicate hydrate . Silica flour or silica sand is commonly used to prevent strength retrogression by modifying the hydration chemistry, and it can be used with all classes of Portland cement. The addition of 30 to 40% silica is usually adequate to produce a set cement with low permeability (< 0.1 millidarcy) that overcomes the problems of strength retrogression, though additions can range from 30 to 100%. At high temperatures, silica causes the reaction with cement and water to produce xonotlite instead of tobermorite. Xonotlite is a lot stronger and results in a significantly smaller increase in permeability."

4.2 Antigas Migration Slurry Design for HPHT Wells

Gas migration represents 25% of the primary cement jobs failures. One of main problems for achieving zonal isolation is fluid migration in the annular space after well cementing. The main factor preventing the fluid from entering the cement is hydrostatic pressure of cement column and the mud above it. This pressure must be greater than pore pressure of gas-bearing formation to prevent fluid invasion into cement column. Besides, it must not exceed fracturing pressure of the formation to avoid losses. The ability of the cement slurry to transmit hydrostatic pressure, that affects the total hydrostatic pressure of the annular column, is a function of the cement slurry gel strength(Vazquez *et al*., 2005) . The higher the gel strength, the lower is the transmissibility of the annular hydrostatic pressure.

The length of time from the point at which the fluid goes static until the SGS (Static Gel Strength) reaches 100 lb/100 ft^2 is referred to as the "zero gel" time. When the (SGS) value reach 100 lb/100 ft^2 it starts to lose its ability to transfer hydrostatic pressure. When the SGS value reaches 500 lb/100 ft^2, the fluid no longer transmit hydrostatic pressure from the fluid (or the fluid above it). The time required for the fluid's SGS value to increase from 100 lb/100 ft^2 to 500 lb/100 ft^2 is referred to as the "transition" time. To control gas migration, the "zero gel" time can be long, but the "transition" time must be as short as possible (preferably, less than 30 minutes).

4.3 Use of Expansion Additive for Improved Cement Bond

Burnt Magnesium Oxide (MgO) can be used as expansion additive. Adding these additives will increase shear bond strength but will reduce compressive strength although still higher than recommended minimum value. The value of shearbond strength and compressive strength are reduced proportional to the increment of burning temperature of MgO, generally, the higher the burning the temperature, the harder the MgO gets and the harder it is for the MgO to react with cement. Burning Magnesium Oxide is done to slow down their hydration process when in contact with water. These additives are fully hydrated after setting of the cement, which allows them to provide excellent expansion at curing temperature up to 550^{o}F.

4.4 Efficient Displacement of Mud

The most important factor in obtaining a good primary cement job is properly displacing the drilling fluid. If the mud is not properly displaced, channels and or pockets of mud may be left in the cemented annulus, which can lead to inter-zonal communication and casing corrosion. Assuming adequate bulk displacement has taken place, bonding of the cement to the pipe can be less than desirable should said surfaces not be conducive to cement bonding. Coatings from mud additives (polymers, corrosion inhibitors, etc) and non-aqueous mud systems can interfere with the bonding between the cement sheath and the pipe surface. Such poor bonding is typically reported as a micro annulus as viewed by a cement evaluation log and is often blamed for poor zonal isolation either via immediate inter-zonal communication. One of the aspects of ensuring an annular seal during a cementing operation after achieving bulk displacement of the drilling mud is bonding of the cement to the formation and wellbore surfaces.

Spacers and flushes are effective displacement aids because they separate unlike fluid such as cement and drilling fluid, and enhance the removal of gelled mud allowing a better cement bond. Compatibility test of the mixture of the fluids with the spacer must be conducted to ensure there will be no incompatibility problems when pumped into the well bore. Mud removal is important in all cementing as the interface between the cement and the formation is affected by its effectiveness, but it is particularly crucial in HPHT wells to achieve a good cement placement and a good cement/formation bond. For a mud to be displaced effectively it must (Yetunde & Ogbonna, 2011):

(1) Have a low plastic viscosity to yield viscosity ratio, P.V/Y.P.

(2) Have a minimal gel strength development.

(3) The design of drilling fluid and displacement is important in cementing, because there must not be incompatibility issues which could cause sludge formation and downhole problems.

4.5 The Effect of Temperature

In HPHT wells, the slurry becomes sensitive to high temperature so that the thickening time of the slurry is highly reduced, causing the cement set faster than in average temperature wells. Temperature also affects the rheological properties of the cement slurry. Plastic viscosity (PV) and yield viscosity decrease with an increase in temperature. Accurate prediction of bottomhole circulating temperature (BHCT) is also very crucial in cementing, because a change as small as 5 °C in the temperature can result in a large change in thickening time. There are two temperatures that we should consider:

Bottomhole Circulating Temperature: this is the temperature the slurry encounters as it is being pumped into the well and it is the one that affects thickening time.

Bottomhole Static Temperature: this is temperature of the formation and it is the temperature the slurry will be subjected to after circulation has stopped for a period of time.

4.6 The Effect of Pressure

Pressure has effects on both the well and the drilling fluid and cement slurry. In cases where the pressure had not been properly estimated, the selected casing will not be able to withstand the pressure from the formation, which will invariably lead to a collapse of the casing in the well and therefore a kick is encountered. Weighting agents are used to create the minimum over balance and they reduce the pumpability of the cement thereby accelerating the development of premature compressive strength. The Class G cement mechanical properties were measured under the pressure of 2,610 psi, the temperature of 212 °F (Mazero, 2012). The result shows that the compressive strength of the cement increases with curing temperature.

Finite element method was used to study the effect of cementing complications on HPHT wellbore integrity in two dimension and three dimension wells. As shown in Figure 31, for different wellbore angles, the maximum casing von Mises stress occurs between the cement channel angle of 80 and 120°. Different cements show different stress development in long term in the HPHT wells. Figure 32 the low density cement, shows advantage of stress improvement along with time. Figure 33 shows how a crack can develop in the cement sheath esp. at HPHT condition (Al-yami *et al*., 2012; Teodoriu *et al*., 2012; YuanAl-yami *et al*., 2012; YuanSchubert *et al*., 2012). As the depth of well increases, the increased hydrostatic head causes an increase in ECD due to compression and increase in temperature causes a decrease in ECD due to thermal expansion. Cementing in deepwater wells is a complex operation compared to traditional cementing operations on the shelf and land.

Here are the challenges in HPHT cementing which should be properly identified (Proehl, 2006).

(1) Small Annulus in Deep Wellbore

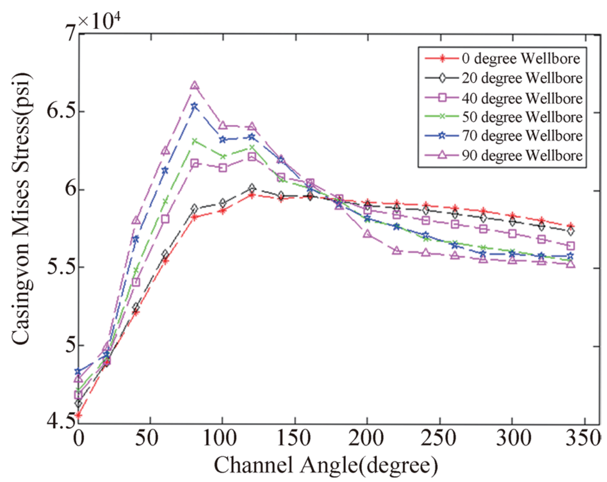


Figure 31
The Effects of Cement Channel Angle and Wellbore Angle on Casing von Mises Stress

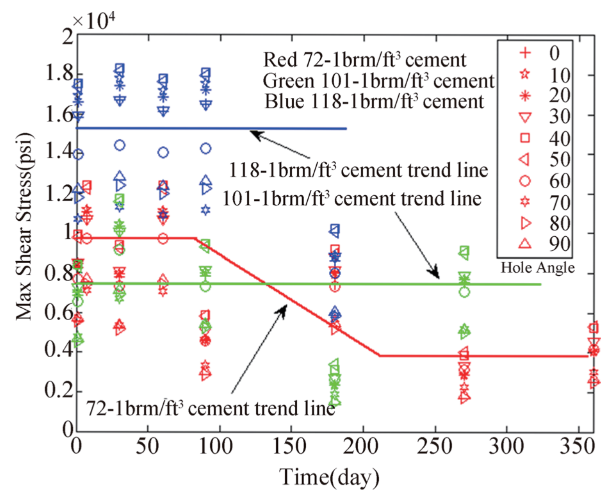


Figure 32
Cement Max Shear Stress as a Function Time

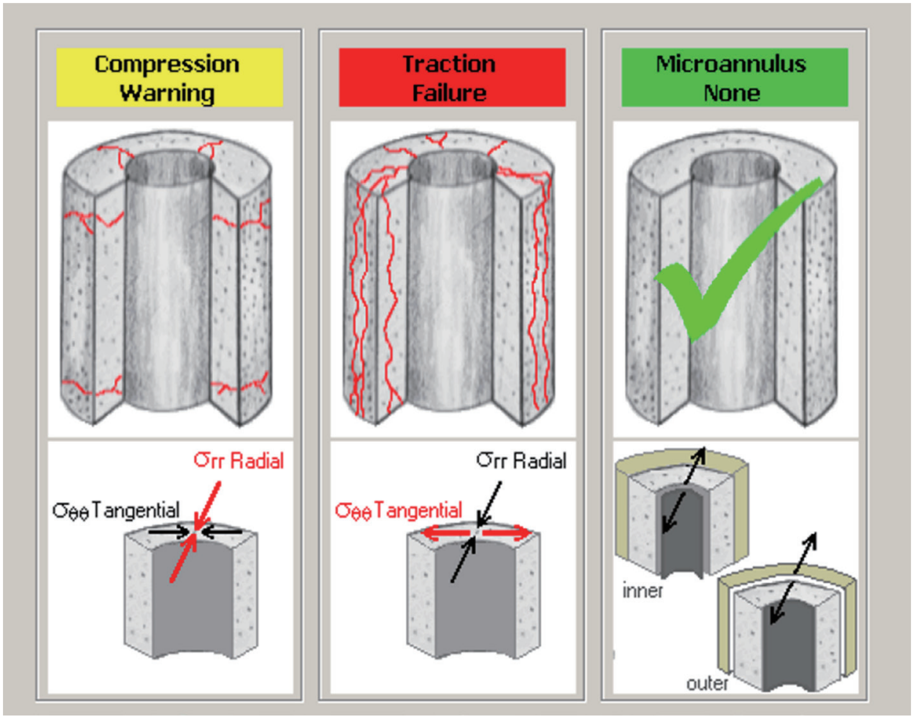


Figure 33
Cracks in the Cement Sheath Can Occur esp. at HPHT Condition

- No returns during cement job
- Difficulty with mud removal and high ECDs
- Small cement/sealant volumes and contamination issues

(2) High Temperature High Pressure Environment
- Accurate temperature prediction for cement job, particularly in deepwater
- Long placement times
- Cement retrogression and instability at high temperatures

(3) Cement/Sealant Long-term Integrity in HPHT Environment with H_2S and CO_2 Present
- Corrosion issues
- Material selection

(4) Multiple Targets Possible but Very Difficult to Achieve
- Narrow pore pressure-fracture gradient window
- Lost circulation
- Wellbore stability/hole collapse issues
- Cross flows and water flow
- Tight annular clearance

(5) Intervention/Remediation Difficult or Unlikely
- Pipe/hole size small
- Pressure and temperature too high for some equipment

(6) Salt Complications
- Optimizing placement technique through salt zones
- Minimizing washout in salt sections
- Cement/sealant sheath integrity across salt formations
- Deformation of salt over the long-term

(7) Delta Temp and Delta Pressure Gradients
- Induced stress due to cyclic loading
- Plastic deformation of sealants can occur

(8) Managing Pressure and Temperature throughout Well Life
- Thermodynamic issues associated with deep production at surface temperatures
- Failure of tubular equipment
- Managed pressure drilling (MPD) technology needed to control well

5. HPHT COMPLETION CHALLENGES

HPHT conditions are pervasive in deepwater environments and affect every aspect of the production process, from drilling risers to sensors to safety control valves to blowout preventer (BOP) control systems. This environments have been a reality in shallow-water regions such as the Gulf of Mexico (GOM) shelf for years. In deeper areas, where high pressures and temperatures don't often exist simultaneously, pressure is driving innovation. Challenges of completing deep HPHT wells are very significant. Novel completion techniques, which allow wells to flow at increasingly higher rates without damaging the near-wellbore area, are raising not only productivity but also wellhead temperatures. Higher rates bring high temperatures to the surface, with liquid being a more-efficient temperature carrier than gas. Water present in the flow stream or annulus also assists in transferring heat up the borehole (Proehl, 2006).

Metallurgy of downhole tools, stability and longevity of electronic tools can be significantly impacted at extreme HPHT conditions, Figure 34 (Mazerov, 2011). Acid gases, H_2S and CO_2, have severe cracking and weight-loss consequences when encountered in significant concentrations. H2S should be reckoned with whenever it is detected, and sour-service measures should be implemented whenever concentrations greater than 0.05-psi partial pressure are encountered. Temperature and reservoir fluids must be matched to the proper material or the operator can spend a bundle on shiny pipe and have it degrade in a hurry. Unfortunately, there is no clear-cut answer; each well must be designed based on its unique environment. According to the DeepStar report the HPHT completion challenges are:

(1) Completion Fluids
- Hole Stability – fluid density is currently limited to 20 lb/gal
- Corrosivity – new alloys may require new corrosion control
- Fluid Stability – testing equipment for 500°F evaluation
- Formation compatibility – testing equipment for 500°F evaluation

(2) Stimulation
- Proppants – Current technology limited to 400 °F and 25 kpsi
- Transport fluids – Higher density to counter act friction pressure

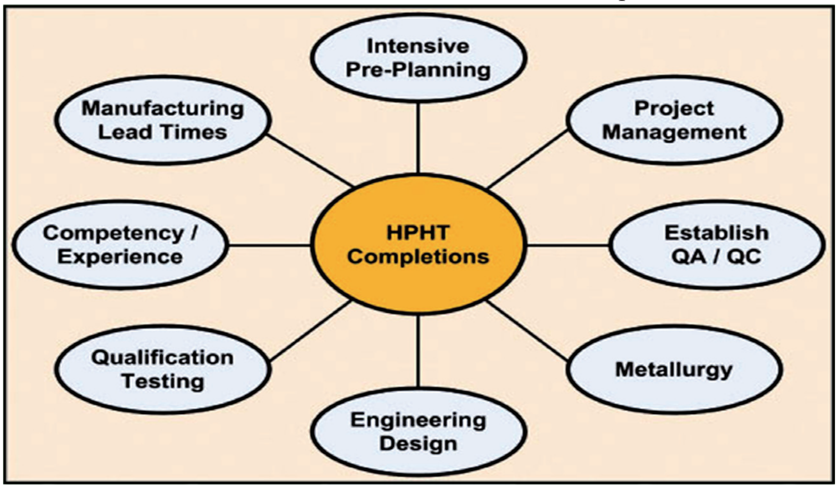


Figure 34
Steps Should be Taken for a Successful HPHT Completion

- Wellhead Pressure Control – Isolation equipment pressure limits are currently 20 kpsi. Subsea operation required.
- Test equipment – Laboratory equipment for testing proppant function and formation compatibility is currently rated to 400 ºF

(3) Flow Assurance/Production Chemistry
- Metering systems for chemical injection
- Injection points-much deeper than current practice
- Produced fluids may require improved control chemistry.
- Laboratory test equipment for evaluating chemical control limited to 20 kpsi.

(4) Perforating
- Ignition and detonation of explosive charges – limit is 400 °F to 450 °F
- Mechanical Reliability of Cases – Current cases collapse at pressures above 20 kpsi.

(5) Completion Equipment
- Seal Technology – Current limit for dynamic seals is 400 ºF.
- Operation and Maintenance – Reliable remote control and minimum maintenance requirement are dictated by extreme depths.
- Mechanical integrity – Large temperature gradients up hole caused by hot produced fluid flow impose extreme mechanical stresses on casing and completion equipment. Current mechanical limits are 400 °F.

(6) Complex Well Completions
- Electronics, power, and flow control equipment that withstand 500 °F
- Telemetry that functions at 500 °F

(7) Well Testing
- Surface equipment must cope with long flow periods
- Test equipment limited by operating temperatures and pressures
- Wellbore storage can necessitate longer shut-in periods
- High density, high solids drilling fluid can plug pressure ports, reduce tool reliability, and stick the test string after settling
- Hydrate formation can plug lines

(8) Packers

- Pipe movement and high compression loads at the packer
- Mechanical and fluid friction increases with well depth and vertical deviations
- Thermal cycling and tubing stresses result in excessive burst and collapse pressures
- Most packer and seal materials are reliable to 350–400 °F and 10,000–12,000 psi

(9) Elastomers

- As temperature increases, extrusion of the elastomeric sealants is likely.
- High temperatures shorten elastomer performance life.
- Surface pressure tests prove difficult since high temperature elastomers may not seal at ambient temperatures.

(10) Wireline Testing

- Measurement components become unreliable according to the length of time spent downhole.
- Currently cannot withstand temperatures above 250 °F.
- Equipment
- Motorized machinery adds to downhole temperatures.
- Thermal shielding may influence readings.
- Electronic components cannot withstand HPHT conditions.

(11) Smart Wells

To achieve optimum production, complex reservoir management is required. Smart well is similar to completion equipment with the addition of inflow control, enhanced measurements, and reservoir management.

- Electronics – Current technology is limited to 15 kpsi and 275 º F.
- Power – Current battery limit is 350 º F.
- Dynamic Seals – Current limit for dynamic seal technology is 400 ºF.
- Maintenance – Current systems require ability to replace or calibrate components

6. UNCONVENTIONAL RESOURCES AT HPHT CONDITION

According to the Secretary of Energy Advisory Board (SEAB) natural gas is the cornerstone of the U.S. economy, providing a quarter of the country's total energy. While total domestic natural gas production grows from 21.0 trillion cubic feet in 2009 to 26.3 trillion cubic feet in 2035, shale gas production grows to 12.2 trillion cubic feet in 2035, when it makes up 47 percent of total U.S. production—up considerably from the 16 percent share in 2009. Hydraulic fracturing and horizontal drilling made North American unconventional gas plays far more lucrative for producers (DOE 2012). Haynesville Shale came into prominence in 2008 as a potentially major shale gas resource and it is doubtlessly, one the most important shale-gas resource plays which is located in East Texas and Louisiana, Figure 35.

Approximately 85% of the wells drilled in Haynesville are horizontal while only 15% are vertical. More than 300 wells in Haynesville and Deep Bossier (South

Source: U.S.Energy Information Administration based on data from various published studies.Canada and Mexico plays from ARL.
Updated: May 9, 2011

Figure 35
North American Shale Plays

Dallas) have been drilled with the bottom hole pressures between 350°F to 380°F, bottom hole pressures between 10,000 psi and 15,000 psi (0.9psi/ft) and vertical depths between 12,000ft and 19,000ft. The Haynesville's higher reservoir pressure has allowed wells to produce at far higher rates compared to other shale plays in North America. Payouts in the Haynesville are often measured in months, compared to years in other plays. Utilizing MPD technology in Haynesville yielded in $2.4 million reduction in project cost in four wells, improved ROP and 48% improvement in lower hole sections in the days vs. depth ratio, with total depth reached 15 days ahead of schedule. The reduction in drilling days, along with lower oil-based mud densities, resulted in savings on mud averaging $100,000 per well, or nearly 25%, compared with the six conventionally drilled wells (Bland. 2011).

7. NATIONAL ENERGY TECHNOLOGY LABORATORY, DEPARTMENT OF ENERGY, U.S.A.

The National Energy Technology Laboratory (NETL) is owned and operated by the U.S. Department of Energy (DOE). NETL supports DOE's mission to advance the national, economic, and energy security of the United States, Figure 36. Huge resources of unconventional gas are locked up in tight-gas sands in the Gulf of Mexico (GOM), Rocky Mountains, Texas, Oklahoma, and the Appalachian Basins. However, there are still large cost and technological hurdles to over-come before significant quantities of gas can move from the possible resource category to proved developed producing reserves. A considerable amount of this gas is in deep (>15,000 feet) reservoirs. Recently a major oil company announced plans to drill in excess of 30,000 feet below the mudline on the continental shelf of the GOM. The drilling environment at these depths will be ultra high pressure (approaching 30,000 psi) and extreme high temperature (> 600 °F or 316 °C) (Ohme, 2007). Durable and incorporate rugged electronics that can withstand the extreme conditions encountered in deep gas formations. Another critical challenge is to develop new models for estimating critical downhole parameters in these high-risk wells (Anna, 2006).

Despite the presence of lots of uncertainties in history matching (Jafarpour & Tarrahi, 2011) in June 2006, the Department of Energy announced the selection of cost-shared research and development projects targeting America's vast, but technologically challenging, deep natural gas resources. These projects have focused on developing the advanced technologies needed to tackle drilling and production challenges posed by natural gas deposits lying more than 20,000 feet below the earth's surface. There, drillers and producers encounter extraordinarily high temperatures (greater than 400 °F) and pressures (greater than 15,000 psi), as well as

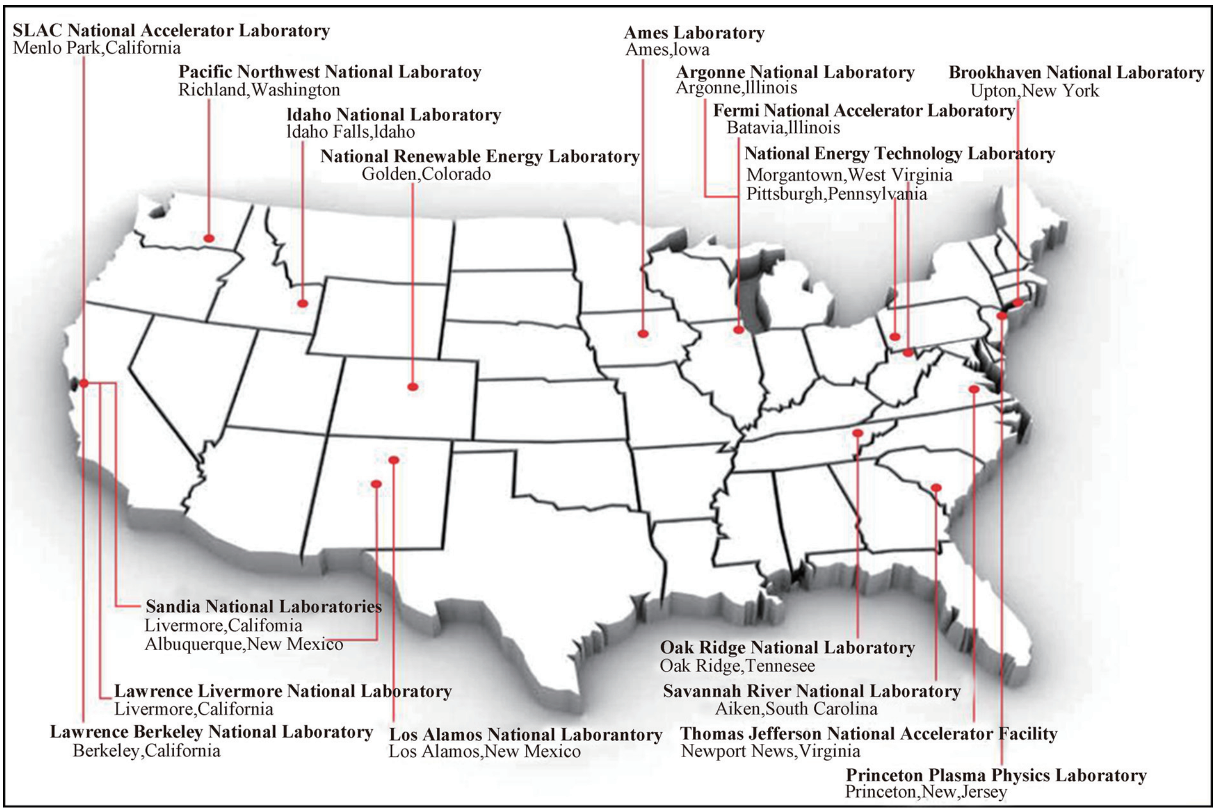


Figure 36
National Laboratories Across the USA

extremely hard rock and corrosive environments .” Deep Trek was created to address driller and producer needs in coping with the extremes of temperature, pressure, and other harsh conditions they encounter when drilling, completing, and producing below 15,000-20,000 feet. The combination of such conditions stretches the limits of technical capabilities, often leading to increased risks and excessive equipment wear and failures. These circumstances also add up to sharp increases in well costs. With an ultra-deep well, the last 10 percent of the bore hole can account for 50 percent of the well’s cost.

Accordingly, with such high risks and costs, only the biggest and most promising of the deep gas prospects have been drilled. DOE estimates that onshore and offshore U.S. deep reservoirs hold 169-187 trillion cubic feet (Tcf) of gas resources. That compares with the nation’s total proven conventional natural gas reserves estimated at 192 Tcf. To date, less than one percent of all wells drilled in the United States have penetrated below 15,000 feet, yet their production accounts for nearly seven percent of domestic production. Deep Trek focuses on developing an integrated deep drilling and deep imaging system that will enable the economic recovery of an additional 100 Tcf of natural gas through 2020. The objective of this latest DOE solicitation is to develop the new high-temperature, high-pressure drilling technologies needed to successfully recover the nation’s deep gas resource.

One of the primary research areas for geologic and environmental systems (GES) is drilling under extreme HPHT conditions. NETL’s Extreme Drilling Laboratory (XDL) research program focuses on improving the economic viability of drilling for domestic oil and natural gas located in deep (>15,000 feet) and ultra-deep (>25,000 feet) formations at high-pressure, high-temperature (HPHT) conditions. The XDL provides a unique platform for researching drilling dynamics at the cutter/rock interface between the drill bit’s cutting tool and the subsurface rock formation under such extreme conditions, Figure 37. The goal is to develop new materials, such as improved fluids used to support the drilling process, and to optimize drilling method that reduce the cost of deep drilling. It was also planned to develop and test new sensors for extreme drilling with the initial focus on Sic systems (potential for sustained operation >350 °C). Integration of Chandler Model 7600, the extreme HPHT viscometer, for HPHT rheological measurements was done to quantify drilling fluid properties at UDS test conditions. XDL is also capable of investigating HPHT problems related to drilling geothermal wells and injection wells needed for the subsurface injection and storage of greenhouse gases or carbon sequestration.

With a capacity of 727-million-barrels, U.S. Strategic Petroleum Reserve is the largest stockpile of government-owned emergency crude oil in the world. The 2012 Annual Plan is the sixth such plan produced since the launch of the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program. It reflects the important shift in priorities towards safety and environmental sustainability initiated in the 2011 Annual Plan and is also consistent with the US President’s Office of Management and Budget directive for refocus of the funding to support R&D with significant potential public benefits.

Domestic deepwater and ultra-deepwater oil and gas resources, and domestic unconventional natural gas resources, continue to be significant contributors to

Figure 37
NETL’s Extreme Drilling Laboratory (XDL), Ultra-Deep Single-Cutter Drilling Simulator, 30,000 psi, (~500 °F), in the Right

America's energy supply portfolio. As with last year's annual plan, the 2012 Annual Plan proposes scientific research that will quantify and mitigate risks associated with oil and gas exploration and production onshore and offshore, thereby improving safety and minimizing environmental impacts. This will ensure that the federal government's understanding of the risks associated with oil and gas operations both in the Gulf of Mexico and onshore operations keeps pace. The research discussed in this annual plan will be administered by the Research Partnership to Secure Energy for America (RPSEA), which operates under the guidance of the Secretary of Energy.

RPSEA is a consortium which includes representatives from industry, academia and research institutions. RPSEA's expertise in all areas of the exploration and production value chain ensure that the Department of Energy's research program has access to relevant emerging technologies and processes, and that projects are designed in a way that have a direct impact on practices in the field.

8. 2012 ANNUAL PLAN ULTRA DEEPWATER, UNCONVENTIONAL NATURAL GAS, OTHER PETROLEUM RESOURCES RESEARCH AND DEVELOPMENT PROGRAM REPORTED TO CONGRESS

Increasing the understanding of complex fluid phase behaviors that occur under conditions of extreme pressure and temperature, and develop advanced models of hydrocarbon behavior under these conditions, has been one of the scopes of NETL. This project focuses on developing an improved understanding of complex pressure-volume-temperature (PVT) relationships for mixtures of flowing fluids (water, gas and oil) under extreme temperatures and pressures (>19,000 psia bottomhole pressures and >250 degrees °F).

Davani (2011) derived an HPHT gas viscosity correlation using a set of measured viscosities of pure and mixtures of methane, nitrogen and CO_2. An oscillating piston viscometer was used to measure viscosities of mixtures of nitrogen and methane with different compositions up to 25,000 psi and 350 °F. (Davani, 2011; DavaniKegang *et al*., 2009; DavaniLing *et al*., 2009). Studying variations in behavior when these fluids include brine, hydrogen sulfide, and carbon dioxide and conducting experimental and theoretical studies to predict the behavior of petroleum liquids under the high pressure and temperature conditions encountered at great water and formation depths have had an utmost importance. Hydrocarbon density and viscosity at temperatures ranging from 50 to 250 °C, and pressures up to 280 MPa should be measured experimentally and advanced models should be developed and validated for both of these important fluid properties.

Thermodynamic and transport properties of fluids focuses on three related activities:

- Development of a comprehensive and thorough database of thermodynamic and transport properties of constituents consistent with petroleum extraction at Ultra Deep Water (UDW) conditions.
- Assessment of conventional and development of new Equation of State models to accurately predict thermodynamic and transport properties at UDW conditions
- Development of high-pressure, high-temperature viscosity standards

The design investigation of extreme high pressure, high temperature (XHP/XHT) subsurface safety valves (SSSV) project looked at several conventional and unconventional well safety valve designs and attempted to determine gaps and remedy issues associated with them for pressure and temperature conditions from super-cooled ambient pressure to 30,000 psig and 350 °F. Through finite element analysis, historical records, and lab tests, the project identified design problems that would be considered flaws in extreme HPHT applications.

Different materials were analyzed to improve the design characteristics, but they did not solve the problem. Although the project was unable to develop a solution to the extreme HPHT problem for SSSVs, the information that resulted from the work will form the basis of additional work to follow to improve the reliability of these important safety RPSEA Draft Annual Plan 61 November 2011 devices, which are used in wells as emergency shut-off devices below the mudline and are critical in cases such as wellhead shearing.

9. WELL GROWTH DUE TO HIGH TEMPERATURE

Well growth is another phenomena that is directly linked to high temperature fields. Due to the high temperature and material expansion, the whole well structure will be lifted up during the production phase. The subsea template structure is designed so that the well structure is independent from the template and therefore will not cause any damage for the template structure itself. The movement of the well structure will be taken up by the flexible connection between the x-mas three and the production manifold (Gjonnes and Myhre, 2005).

CONCLUSION

Based on the analysis of various HPHT case studies around the globe and researching the industry's capabilities, the major obstacles encountered when drilling ultra and extreme HPHT wells are formation and well evaluation tools. This identifies several areas that require more attention such as elastomers, battery technology, and electronics/sensors, alternative sealing agents, modified testing procedures and equipments, HPHT cement integrity, proper zonal isolation and finally new euqation of state to better predict the behavior of petroleum liquids under elevated pressures and tempertaures. HPHT well drilling should also benefit from ROP optimization through careful selection of bits, drilling fluids, motors, and string design. Test fixtures will be required to establish equipment design criteria and to provide a means for testing well equipment. There are also unique safety concerns for HPHT operations that must be addressed for future technology development and applied engineering activities. Flow assurance is the most critical issue in completion technology since production is paramount to the success of these developments. Completion fluids, completion equipment, and perforating are areas that require more focus.

The industry is undertaking significant investment in equipment and materials to generate the technologies and qualify the equipment for future HPHT wells that will soon require limits of 30,000 psi and/or temperatures up to 500 °F. API and ASME have worked together on new standards, performance ratings, and quality assurance requirements for new equipment or product. Right metallurgy must be available while sourcing metals such as nickel, alloys or possibly titanium might be a challenge ahead. Also, polymers and seals must be developed to withstand increased extreme HPHT conditions while retaining mechanical properties, chemical performance, and well fluid compatibility.

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