DeepStar CTR 7501

Drilling and Completion Gaps for HPHT Wells in Deep Water

Final Report

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1. Introduction

1.1 Background

DeepStar is the industry's preeminent collaborative deepwater technology consortium of oil companies, vendors, regulators, universities and research consortia. This globally-aligned, cooperative effort is focused on identifying and developing economically viable methods to drill, produce, and transport hydrocarbons from deepwater environments. Phase VII, initiated in January 2004 by DeepStar under CTR 7501, concentrates on current technology available for drilling and completing high-pressure, high-temperature (HPHT) wells in 4,000–7,500 ft water depths. Due to its parallel interest in gauging the most critical gaps in HPHT technology, the Minerals Management Service (MMS) co-sponsored this effort under the Technology Research and Assessment Program.

Triton Engineering Services Company was tasked by the group with identifying technological requirements to conduct successful operations on future deepwater HPHT wells. Triton enlisted the services of CSI Technologies for their expertise in cementing and completions. By defining gaps between existing and required technologies, manufacturers and industry vendors were able to develop scope, time, and cost proposals to resolve any disparities.

The future of oil and gas exploration and production may lie in deepwater wells drilled in HPHT and extreme HPHT (xHPHT) environments. The industry has been working to identify and bridge gaps between currently available technology and what is required to drill, complete, and produce wells in HPHT deepwater environments. Deep resources represent approximately 158 TCF (at depths greater than 15,000 ft), and are one of the sources of natural gas that will play an important role in meeting the growing need for natural gas in the United States. The Energy Information Agency estimated that 7% of U.S gas production came from deep formations in 1999. This contribution is expected to increase to 14% by 2010. Much of this deep gas production will come from the Rocky Mountain, Gulf Coast, and GOM sedimentary basins. Challenges for drilling and completing deep HPHT wells are significant. Topics as basic as rock mechanics are not well understood in deep, highly pressured formations.

An interim report issued by the project team on November 30, 2004 described details of the design drivers for HPHT conditions specified by the DeepStar group. It also included casing point selections for four wells in 4,000 ft of water and three in 7,500 ft of water. This final report uses existing data as a foundation on which to expand testing parameters of current deepwater technologies.

A base case, a sensitivity case, and various well profiles were discussed with DeepStar participant companies considered to have significant interests in deepwater technology. Baker-Hughes, FMC, Halliburton, M-I Swaco, Schlumberger, Smith International, and Technical Industries were selected for this purpose. Multiple product and service lines are represented, including wellheads, drilling fluids, LWD/MWD, bits and cutters, drilling systems, inspections/QC/development of standards, and openhole logging. Several industry sources contributed information that helped define HPHT drilling issues; these sources included the DEA, DeepTrek participants, industry experts, and drilling engineer consultants with experience in extreme deepwater environments.

The effect of high temperatures on equipment continues to be the primary obstacle in successful HPHT well completion. In addition, continuing demand for real-time data gathering and formation evaluation remains unmet even though the risk associated with downhole extreme conditions would be minimized. Based on this study, drilling to total depth in extreme environments is difficult and costly, but is achievable.

Influx control (prevention and handling) of reservoir fluid into a well (kicks) is always central to drilling safety, but in HPHT wells the dangers from a kick are amplified[1] Future developments and advances in

[1] MacAndrew, Robert: "Drilling and Testing Hot, High Pressure Wells," *Oilfield Review*, April 1993.

current technology must adequately address the three issues at the heart of HPHT drilling safety: kick prevention, kick detection and well control. For example, the volume of an HPHT gas kick remains virtually unchanged as it rises in the annulus from 14,000 to 10,000 ft (4265 to 3050 m). From 10,000 to 2,000 ft (610 m) its volume triples. But from 2,000 ft to the surface, there is a 100-fold expansion. There are other safety concerns that have a similar exponential increase of exposure that must be taken into account while new protocols are developed to drill wells in HPHT deepwater environments. HSE issues with regard to hot drilling fluids and tripping hot drill strings are also critical to the success of future operations.

1.2 Statement of Purpose

The purpose of DeepStar CTR 7501A study is to identify, understand, and prioritize gaps that exist between current capabilities and required capabilities to drill and complete the defined HPHT deepwater wells. The aim is an understanding that is sufficient for vendors to develop project scope, time, and cost proposals to close identified gaps.

1.3 Approach to Research

Two parallel approaches were pursued to document the industry's capabilities in HPHT operations. These were:

1. **Analysis of Historic Well Data**
2. **Survey of Industry Service Providers**

These approaches were designed to contrast what the industry believes (claims) are its performance limits versus what has actually been achieved in recent applications.

Recent historic well data were reviewed in detail to discern patterns of failure for tools and equipment in HPHT operations. This study included 31 deepwater wells and four "deep" shelf wells. Most of these are in the GoM. Data for the deepwater wells were derived from Triton's in-house database or contributed by several participant companies in CTR 7501. Six of the deepwater wells encountered temperatures greater than 300°F at total depth. The four shelf wells were contributed by a company that is not a DeepStar member. All four deep, directional wells encountered temperatures greater than 300°F, and all featured multiple failures of MWD and LWD equipment and drilling motors.

The service industry was surveyed to document the capabilities of current tools and systems. The project team developed a series of interview questions, and interviewed several service companies in an iterative process. Based on their responses, we identified physical design drivers and defined the current practice and state-of-the-art technology.

Both historic well data and service company information were then used to Define limits of existing skills, equipment, and services. From there, we identified gaps and estimated the time, cost, and technical complexity required to close those gaps to achieve DeepStar performance objectives.

1.4 Taxonomy of Technology Gaps

Early in the process of examining technology gaps for HPHT wells in deep water, it was recognized that there are several types of technology gaps that may exist. These are:

1. *Physical technology gaps.* These concern 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.* These concern whether or not a particular operation or method 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.

These gaps are inter-related and can be very difficult to segregate under certain circumstances. For example, modern drilling standards call for very strict real-time monitoring and control of wellbore paths. Control of wellbore paths is made possible by combining capabilities of MWD, LWD, and various tools that adjust wellbore trajectory. In the last 15 years, real-time control of wellbore paths has evolved from being somewhat of a luxury to being a virtual necessity. This transition was driven by the need to control increasing costs and also by the need to meet regulatory requirements. This begs the questions: What happens in the event it is impossible to physically employ any or all of the technology needed to exert real-time control over the wellbore path? What will the regulatory and economic consequences be? What will be necessary to develop and commercialize technologies to extend current capabilities into harsher environments? Can regulatory regimes be relaxed to secure access to needed hydrocarbon supplies?

While there are no simple answers to these questions, we know that the exploration and production industry has a long history of developing technologies to meet emerging challenges. We also know that the first step toward developing technology is to examine what each economic actor wants and needs, define the prize, and negotiate a way to go after it.

1.5 Who Needs What?

In the universe of deepwater drilling and completion, there are generally fours types of actors. These are:

1. Operating companies who integrate economic factor inputs and actually assume the risk in drilling wells
2. Drilling contractors who provide the plant for drilling wells
3. Service companies who provide specialized equipment, materials, and services to amplify the capabilities of the plant
4. Regulatory agencies who define what is permissible (and not permissible) within a general framework of enabling legislation

Each group of actors has specific wants and needs. Operating companies need access to a drilling plant; specialized equipment, materials, and services needed for the plant; and a regulatory environment that allows them to take risks. Generally, drilling technology offers a transitory competitive advantage, at best. The key word is “risk” – the known chance that an event will occur. In general, deepwater drilling rigs are fit to drill deeper, hotter wells than they have drilled up to this time. The operator’s risk associated with technical capabilities of existing drilling rigs is fairly small (and primarily associated with temperature issues) as we look to a future full of HPHT drilling opportunities. Over the past 15 or so years, operators have all but abandoned their basic work with R&D in the development of new enabling and frontier-conquering technology. Savings in direct cost have been offset by the dependence on outside parties to develop appropriate technology in a timely manner. Operating companies must rely on their own human capital, backed up as needed by a “reserve army” of contractor and service company personnel, goods, and services to be successful.

Drilling contractors need to amortize their huge financial capital assets while maintaining or even expanding access to more capital necessary for building and upgrading drilling assets for future work. The specific focus on making assets perform well and safe tends to limit the ability and desire of contractors to engage in development of technology. Generally, drilling technology does not offer a drilling contractor much of a competitive advantage because they have such a huge capital base that must be serviced. Many new drilling technologies are operator-driven and applied by the contractor. Given the capital invested in drilling assets, contractors are not in a strong position to help with technology development even though they intrinsically possess a number of desirable characteristics useful for that purpose. They have very good operational skills, good decision-making capability, and the potential to be an excellent laboratory for technology development and testing, if they choose to do so.

Service companies have become the main vehicle for technology development since the operating companies have basically abandoned that arena. Drilling technology can be a source of extreme competitive advantage for a service company. Service companies need to balance their ability to make money from efforts of their human capital with their need to invest financially in tools and equipment to serve the demands of operating companies. The accelerating rate of technological change exposes service companies to the issue of obsolescence. The threat of obsolescence leads service companies to avoid overbuilding, engage in “just-in-time” delivery of tools and equipment, and to use pricing power whenever possible. Service companies need to see a path leading to good financial returns before they embark on technological development. It should be noted that service companies can share some of their technological risks with other (non-competitive) service companies such as their suppliers. That approach is generally not attractive to either operating companies dealing with technology or drilling contractors.

Regulators need to create a setting where operators can work, exploring and developing the public assets for the greater good of the economy, while serving their mission of protecting public safety and the environment. They also need to be very sensitive to “soft” political issues and be seen as the defenders of the public interest in resource development. Regulatory agencies tend to engage larger issues by funding projects directed toward facilitating and influencing the kinds of higher-risk or longer-term applied powerful commercial development research undertaken by service companies and applied by operating companies.

The commonality among these four actors is that their long- and short-term interests are best served if accurate forecasts of future activity are available, and by knowing the cost of future opportunities. For this study, a detailed cost assessment for deepwater drilling was conducted. The prize available to technology is then defined in terms of the cost of the alternative(s). In the example of wellbore path control, the prize available to HPHT LWD and MWD tools might be defined in terms of the number of wells to be drilled and the cost of surveying every 500 ft with a heat-shielded single-shot tool, or tripping the drill string to run a survey tool on a wireline sonde. Clearly, if regulators, hence operators, did not insist on knowing the bottomhole location, we could avoid developing real-time technology altogether. Clearly, nothing is independent, and nothing is free with regard to technology. The optimal situation occurs when appropriate technology is available to meet physical, economic, and regulatory demands of a particular task at hand.

2. HPHT Design Cases

2.1 Project Objectives

The purpose of DeepStar CTR 7501A study is to identify, understand, and prioritize gaps that exist between current capabilities and required capabilities to drill and complete the defined HPHT deepwater wells. The conditions defined are wells drilled 27,000 ft below mud line with reservoir temperatures in excess of 350°F and reservoir pressures of 24,500 psi. It is explicitly recognized that reservoir temperatures on the order of 500°F are ultimately possible. Sensitivity cases involved wells in 4,000 and 7,500 ft of water, and sub-salt wells in each water depth. The aim is an understanding that is sufficient for vendors to develop project scope, time, and cost proposals to close identified gaps.

2.2 Deepwater Drilling Cases

Defining the value of the prize demands identification of representative well time and costs for HPHT projects. At the outset of CTR 7501, Triton solicited information from the DeepStar group about the distribution of subsurface pressures that might be encountered on future wells. The consensus of the membership was that it would be best if Triton extracted case histories from its files, with the presumption that these case histories (extrapolated/adjusted to the CTR 7501 total depth and water depth conditions) would be representative of the kinds of subsurface conditions to be encountered as wells are drilled deeper. Conditions already encountered in deepwater wells extrapolated very smoothly and easily to the CTR 7501 conditions at greater depth, lending credence to the approach taken by the team.

The DeepStar CTR 7501 criteria call for wells with bottom-hole pressures of 24,500 psi and bottom-hole temperatures greater than or equal to 350°F at 27,000 ft below the mud line. Water depth cases of 4,000 and 7,500 ft with subsalt sensitivities for each water depth were defined. Triton selected seven well cases from its files (Table 1).

Table 1. Representative Well Cases for Time/Cost Analysis

Case A	4,000’ WD	GOM	
Case B	7,500’ WD	GOM	
Case C	4,000’ WD	GOM	Subsalt
Case D	4,000’ WD	GOM	
Case E	7,500’ WD	GOM	Subsalt
Case F	7,500’ WD	W. Africa	
Case G	4,000’ WD	S.E. Asia	

These cases encompass all DeepStar requirements and also provide geographic diversity in areas that are likely to encounter high temperatures and elevated pressures at great depths.

Cost data for the Case Wells are presented in Table 2. The ideal drilling days (roughly equivalent to the technical limit or “P-10” cases) vary from 58.5 to 150.7, averaging 83.6 ±29.2. When all “optional” well activities such as abandonment and probable casing strings are included, overall ideal days vary from 90.3 to 166.2, averaging 111.6 ±23.4. “Ideal” days consist of rotating and tripping time derived from actual records of each well and the statistically-robust flat times for setting each casing string and running a basic wireline log at total depth. MWD/LWD is provided for the duration of each well. No pilot holes are included in the drilling time estimates.

Table 2. DeepStar Case Wells – Time and Cost

	CASE A	CASE B	CASE C	CASE D	CASE E	CASE F	CASE G	AVG	STD DEV
WELL DATA									
LOCATION	GOM	GOM	GOM	GOM	GOM	WA	SEA		
SALT?			S/S		S/S				
AIR GAP	100	100	100	100	100	100	100		
WATER DEPTH	4000	7500	4000	4000	7500	7500	4000		
BML DEPTH	27000	27000	27000	27000	27000	27000	27000		
TOTAL DEPTH	31100	34600	31100	31100	34600	34600	31100		
DRILLING TIME									
IDEAL DAYS	58.46	66.14	62.36	76.27	85.96	85.05	150.72	83.57	29.17
OPT INT CSG			4.23	4.23	4.23				
OPT DRLG LNR 1	11.11	11.11	11.11	11.11	11.71	14.33	7.94		
OPT DRLG LNR 2	13.25	13.25	13.25	13.25					
P&A	7.5	7.5	7.5	7.5	7.5	7.5	7.5		
TOTAL IDEAL TIME w/ OPTS	90.32	98	98.45	112.36	109.4	106.88	166.16	111.65	23.35
LTF	0.571	0.571	0.571	0.571	0.571	0.571	0.571		
TRIP SPEED (ft/hr)	695	695	695	695	695	695	695		
AFE DAYS	91.83	103.89	97.97	119.81	114.33	133.62	236.8	128.32	46.16
OPT INT CSG			6.64	6.64	6.64				
OPT DRLG LNR 1	17.45	17.45	17.45	17.45	18.4	22.51	12.5		
OPT DRLG LNR 2	20.81	20.81	20.81	20.81					
P&A	11.78	11.78	11.78	11.78	11.78	11.78	11.78		
TOTAL AFE TIME w/ OPTS	141.87	153.93	154.65	176.49	151.15	167.91	261.08	172.44	37.68
DRILLING COSTS ($1000)									
AFE COST	$55,469	$75,814	$57,260	$68,068	$81,452	$104,311	$149,048	$84,489	$30,469
OPT INT CSG			$4,671	$4,702	$4,263				
OPT DRLG LNR 1	$8,067	$10,537	$9,681	$9,692	$11,468	$14,601	$6,636		
OPT DRLG LNR 2	$9,086	$12,261	$9,236	$9,373					
P&A	$5,161	$6,756	$5,158	$5,177	$5,298	$5,385	$4,750		
TOTAL AFE COSTS W/OPTS	$77,783	$105,368	$86,006	$97,012	$102,481	$124,297	$160,434	$107,626	$25,548
SUMMARY COST INDICATORS									
COST per DAY ($1000)	$548.27	$684.52	$556.13	$549.67	$678.01	$740.26	$614.50	$624.48	$71.76
COST per DRLD FOOT	$2,881	$3,903	$3,185	$3,593	$3,796	$4,604	$5,942	$3,986	$946
RIG RATE MULTIPLIER for TOTAL	1.69	1.22	1.71	1.69	1.22	1.51	1.89	1.56	0.24

All time not spent in planned rotating and tripping operations or in planned flat spot activities is by definition “lost.” This does not imply the time was unproductive; but rather that lost time did not contribute directly to the most efficient path for drilling the well. The lost time factor (LTF) for complex deep water is 0.571, another statistically robust number. Inclusion of the LTF increases drilling days to a range between 91.8 and 236.8, for an average of 128.3 ±46.2. Adding the LTF to drilling, abandonment, and “probable” casing string days gives a grand total range for the AFE days of 141.9–261.1. Average AFE days are 172.4 ±37.7.

Converting days to cost using prevailing rig and other prices leads to a basic drilling cost range of $55,469k to $149,048k, averaging $84,489k ±$30,469k. Including abandonment and “probable” casing strings results in a final AFE cost range of $77,783k to $160,434k. The average well costs $107,626k ±$25,548k.

The overall daily rate ranges between $548.27k and $740.26k, for an average of $624.48k ±$71.76k. Cost per drilled foot is between $2,881 and $5,942, averaging $3,986 ±$946. The average rig rate multiplier (the number by which the rig rate is multiplied to arrive at an estimated total daily spread cost) is 1.56 ±0.24. For purposes of this study, a rate of $325k/day was assigned to the 4,000-foot water-depth wells (anchored semi submersible unit) and a rate of $450k/day was assigned to the 7,500-ft water-depth wells (dynamically stationed drill ship).

Drilling times for the representative wells are compared in Figure 1. Drilling costs are shown in Figure 2.

Figure 1. DeepStar CTR 7501 Case Well Times

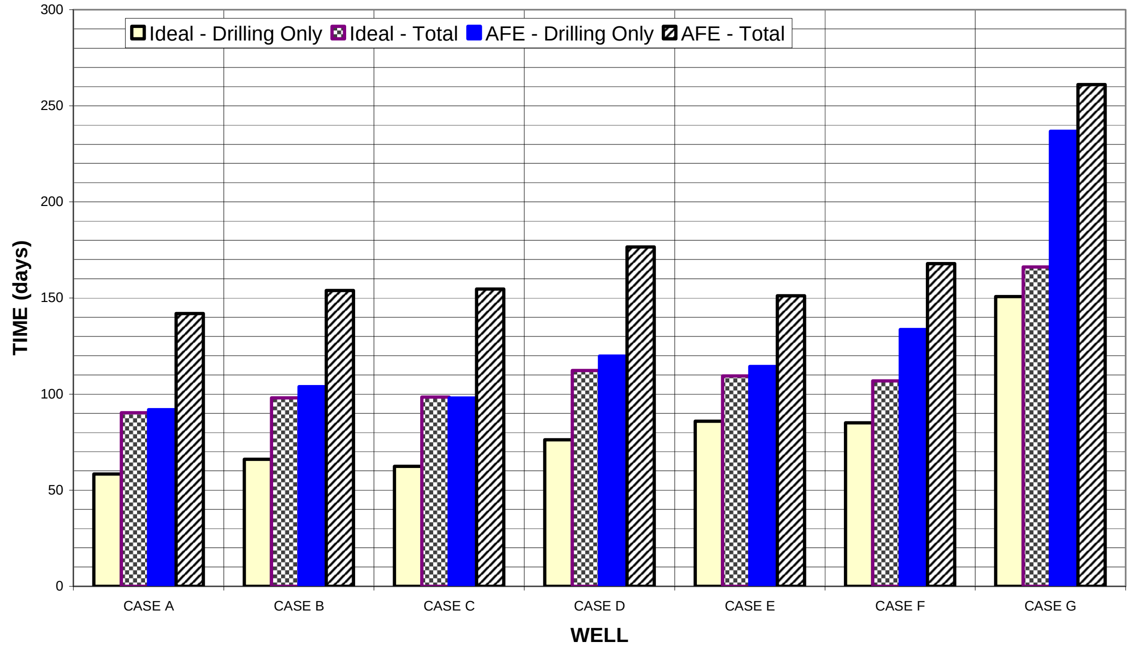
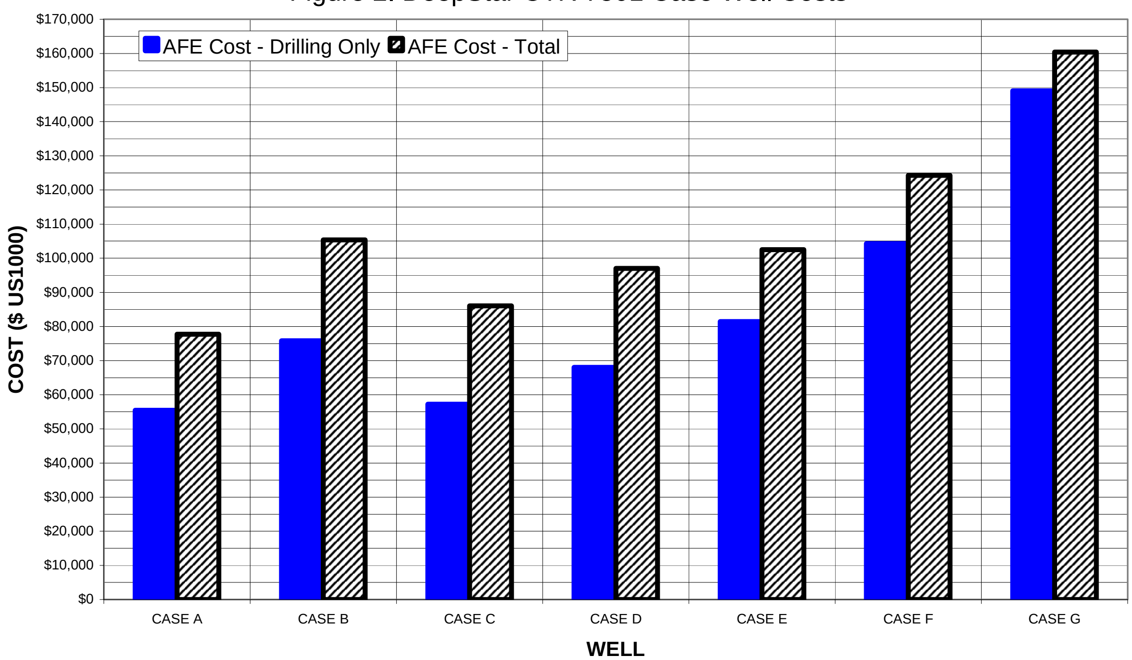


Figure 2. DeepStar CTR 7501 Case Well Costs



2.3 Industry Survey Method

As described previously, a survey of industry service providers was undertaken to document HPHT performance limits, both current and future. The following steps were completed:

- Develop interview questions
- Interview service companies
- Identify physical design drivers

- Identify impact of those drivers on well design
- Define current and state-of-the-art technology for meeting the DeepStar objectives
- Define limits of existing skills, equipment, and services
- Identify gap-closure requirements
- Quantify time, cost, and technical complexity required to close gaps

2.4 Design of Base Cases

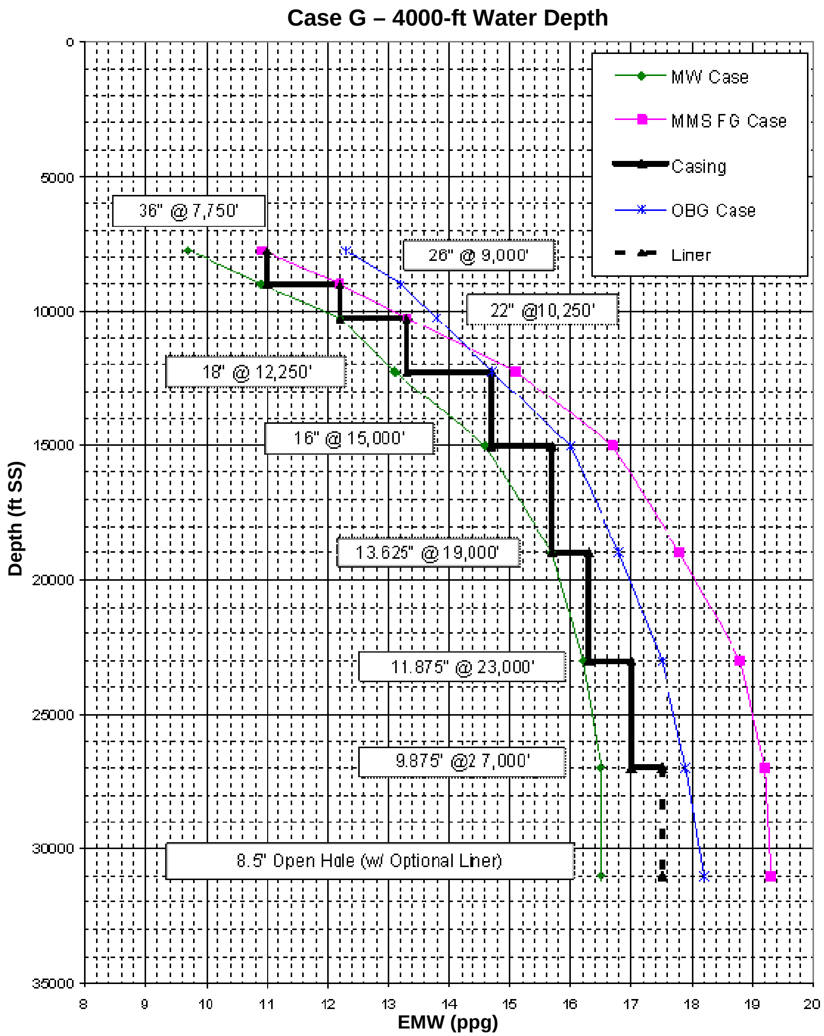
Triton generated several different casing programs to meet objective well conditions. The casing programs and design criteria were used as a basis for the interviews (see Table 2 and accompanying well profiles). Note that these well profiles were selected because the project team concluded that they were representative of real-world situations and allowed comparative analysis of key drilling concerns.

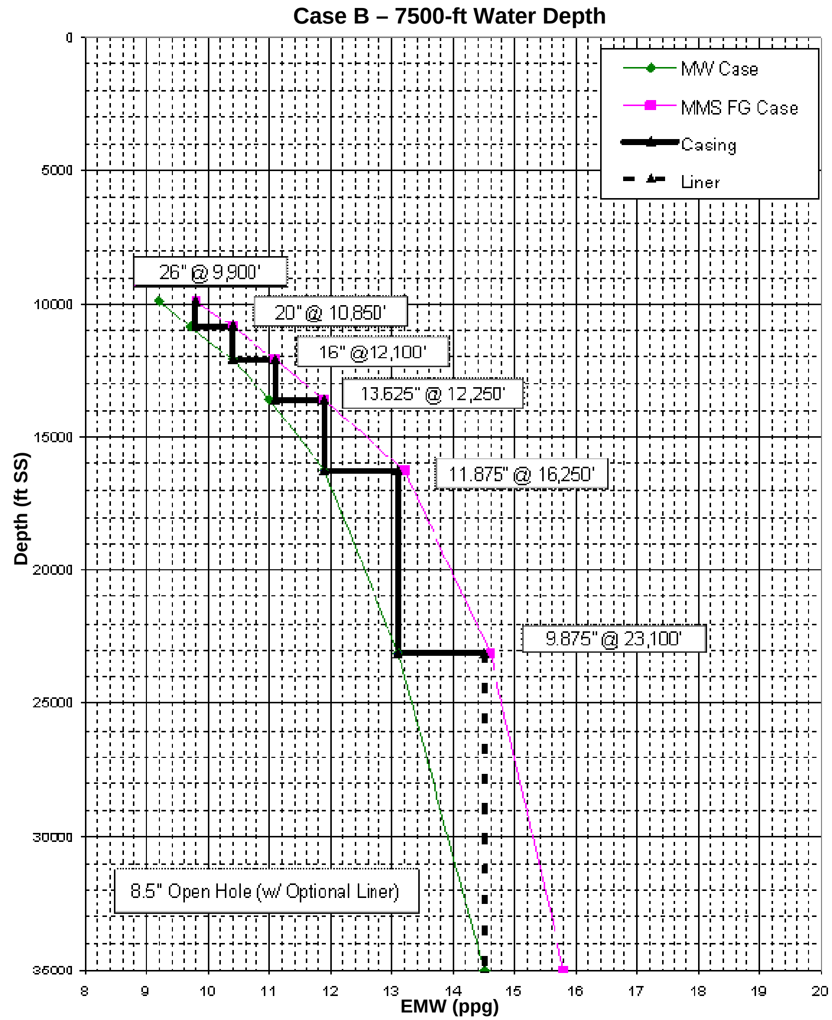
Table 2. HPHT Case Design Criteria

WELL PARAMETERS	BASE CASE	ALTERNATE CASE
Water Depth In Field	4,000 ft	7,500 ft
Number of Producing Wells	6	6
	Non-Subsalt	Subsalt
Hydrocarbon Type	Dry gas with contaminants	Dry gas with contaminants
Net Reservoir Thickness	300–600 ft (Single production zone)	300–600 ft (Single production zone)
Reservoir Rock	Very fine to medium grain subarkoses	Very fine to medium grain subarkoses
Reservoir Type	Dune (50%); Sheet Sand (30%) with jigsaw puzzle discontinuous faults	Dune (50%); Sheet Sand (30%) with jigsaw puzzle discontinuous faults
Reservoir Depth	27,000 ft BML	34,000 ft BML
BHP	24,500 psi	24,500 psi
Pressure Gradient (psi/ft from mudline)	0.84	0.84
BHT	400ºF	500ºF
Temperature Gradient	75 ft/ºF	75 ft/ºF
SIWP	21,000 psi	25,000 psi
Producible Reserves	600 bcfg (75% RF)	600 bcfg (75% RF)
Typical Reserves Per Well	100 bcfg	100 bcfg
Natural Drive Mechanism	Pressure Depletion	Pressure Depletion
Production Well Spacing	Approx. 700 acres	Approx. 700 acres
Initial Production Rate Per Well	100 MMscf/d	100 MMscf/d
Typical Production Rate Per Well	100 MMscf/d and 10 bbl/MMscf liquids	100 MMscf/d and 10 bbl/MMscf liquids

NOTE: The wells are expected to produce at near or at erosional flow velocity limits for most of their productive life. Thus, the largest bore equipment compatible with reservoir conditions should be used.

Figure 3. Well Profiles – Case G and Case B





3. Drilling Assessment

3.1 Issues for HPHT Drilling

Development of new approaches to drilling deep HPHT wells is required to meet engineering requirements while keeping projects economically viable. Developing optimum drilling technologies and techniques must also take place within the framework of completion requirements. For example, casing-while-drilling could significantly decrease the time spent on downhole problems not associated with actual drilling processes (e.g., stuck pipe, lost circulation, and well control situations). This in turn leads to a safer and less expensive drilling operation (fewer people, less pipe handling, fewer trips, and less mud).[2]

Issues listed below represent primary concerns of drillers planning HPHT deep wells. As the state of the art advances, additional concerns will surface that merit evaluation.

3.1.1 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 an exponential decrease in dependability to 350°F.

3.1.2 Slow Rate of Penetration 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.

3.1.3 Well Control

- Pore pressure is near frac gradient causing potential well control problems.
- Mud loss is an issue due to lithology and geopressure.
- Hole ballooning causes mud storage problems. The walls of the well expand outward because of increased pressure during pumping. When pumping stops, the walls contract and return to normal size. Excess mud is then forced out of the well.
- Methane and H_2S (hydrogen sulfide) are soluble in oil-base mud and are released from the solution as pressure decreases. The fluid column is thereby lightened.
- Wellhead design for 25 ksi, 450°F is needed. Current rating is 15 ksi, 350°F H_2S service with work in progress for 20 ksi, 350°F equipment. Similar concerns with BOPE.

3.1.4 Non-Productive Time

- Stuck pipe and twisting off
- Trip Time – caused by tool failure (LWD/MWD) and bit trips
- Suboptimal decision making caused by lack of XHPHT experience (the “learning curve”)
- Safety issues associated with handling hot drilling fluids, hot drill strings

[2] The DOE/NETL Deep Trek Program, Advanced Drilling and Completion Technologies.

Interviews based on the above issues, helped identify gaps in current technology. Management and technical personnel were interviewed to get a broad view of the issues and possible solutions. These gaps and opportunities are summarized in Table 3 according to service line. We conclude that wells can be drilled to conditions defined by base and sensitivity cases, but formation evaluation remains difficult and indeed, very problematic for real-time control and navigation. However, opportunities exist in the areas of improved drilling performance, especially in ROP and well control.

3.2 Drilling Technology Concerns

The following technology concerns were identified by service companies and operators as the principal issues facing drillers operating in HPHT, deepwater environments. Supplied data came principally from service companies as part of the industry interviews. Information from the Department of Energy, Minerals Management Service, and the report's authors augmented the data set.

- Wellheads and casing hangers
- Drilling fluids
- Directional drilling
- LWD/MWD
- Openhole logging
- Bits
- Inspection, QA/QC, and Standards

The principal source for each technology concern is summarized in Table 3.

Table 3. Data Sources for Drilling Technology Concerns

Baker	FMC	Halliburton	M-I	Schlumberger	Smith	Technical Industries
		Bits			Bits	
Drilling Mud			Drilling Mud			
Drilling Systems		Drilling Systems		Drilling Systems	Drilling Systems	
						Inspection
LWD/MWD		LWD/MWD		LWD/MWD		
		Openhole		Openhole		
	Wellheads					

Additional companies, including Compliance Inspection Services and Gatorhawk, participated in the fact-finding phase of this study. However, only those exhibiting advanced technologies were used as benchmarks in their areas of expertise. Those with the most impact on total depth drilling are discussed below; some were combined because of inter-relationships. Inspection, QA/QC, and Standards are covered in investigations conducted by other industry groups, although updating API and NACE standards involving wellheads, drilling fluids and corrosion is recommended. Electronic issues related to openhole logging are presented in other studies.

Service line parameters follow. Table 4 outlines identified service lines, present day issues, and future opportunities for drilling in deepwater HPHT conditions.

3.2.1 Wellheads

- Part of the blow out preventer (BOP) and subsea tree assembly. Addressed in other DeepStar projects.
- Current equipment is rated at 15,000 psi, 350°F H_2S service and can be stretched to 20 kpsi, 400°F H_2S service.
- An upgrade to 25 kpsi, 450°F will require \$2–\$3 million investment.

3.2.2 Drilling Fluids

- Serves as a coolant for LWD/MWD.
- H_2S and gas are soluble in OBM.
- Reduced friction pressure will improve ECD control.
- Mud loss is an issue.

3.2.3 LWD/MWD

- Extending ongoing electronics and sensor projects to achieve DeepStar goals would be advantageous.
- A high-temperature battery is being developed by Los Alamos National Laboratory and is scheduled for completion in 2006.
- A prototype retrievable MWD system rated to 400°F is under development by Schlumberger and will be available by the end of 2005.

3.2.4 Drilling System/Bits

- Terra-Tek and Sandia National Laboratories have demonstrated improvements in ROP and cutter performance for a reduction in drilling costs.
    1. Work at Terra-Tek combined bit and mud studies to improve drilling performance.
    2. Sandia National Laboratories, in conjunction with U.S. Synthetics, has developed cutter technology for improved bit performance. Further enhancements are due by year-end.
- 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 drillstring dynamics as a system offers possibilities to improve reliability and penetration rates.

Table 4. Drilling Technology Service Line Limits

	Pres	Temp	Service	Issues	Opportunities
Wellheads & Casing Hanger *(Also addressed in HIPPS)*	15 kpsi	350°F	H_2S	20k 350°F system will be a stretch of 15k . 25k system will require a totally new design.	Improve sealing technology. Amend API specs. Metal-to-metal sealing required for 25k.
Drilling Fluids ▪ Oil Base Mud ▪ Water Base Mud ▪ Synthetic	30 kpsi 30 kpsi 30 kpsi	500°F 500°F 500°F	H_2S	Friction pressure contributes to losses. Mud cooling is beneficial. Gas and H_2S soluble in OBM.	Reduce friction. Reduce H_2S and methane sol. in OBM. Improve cooling.
Directional Drilling ▪ Motors ▪ Control/Steering ▪ Long Sections	25 kpsi See MWD	425°F See MWD 425°F	300 hr 300 hr	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		275°F 350°F	H_2S H_2S	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. H_2S and gas sensors.
Openhole Logging ▪ All tools ▪ Limited Tools	25 kpsi 25 kpsi	350°F 450°F	H_2S H_2S	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 kpsi	500°F		Penetration rate is low. 10% of normal ROP.	Take a Systems Approach. Bits, Motors, Mud, Drill String. Continue work on cutters.

3.3 Analysis of Historic Well Data

Basic steel drilling tools ("dumb iron") and bits can be used to drill very hot, high-pressure wells. Water-base and oil-base muds demonstrate similar capability. HPHT wells are successfully logged with wireline sondes on a consistent basis. Cementing has been a challenge at high temperatures, but these challenges can be successfully and consistently addressed.

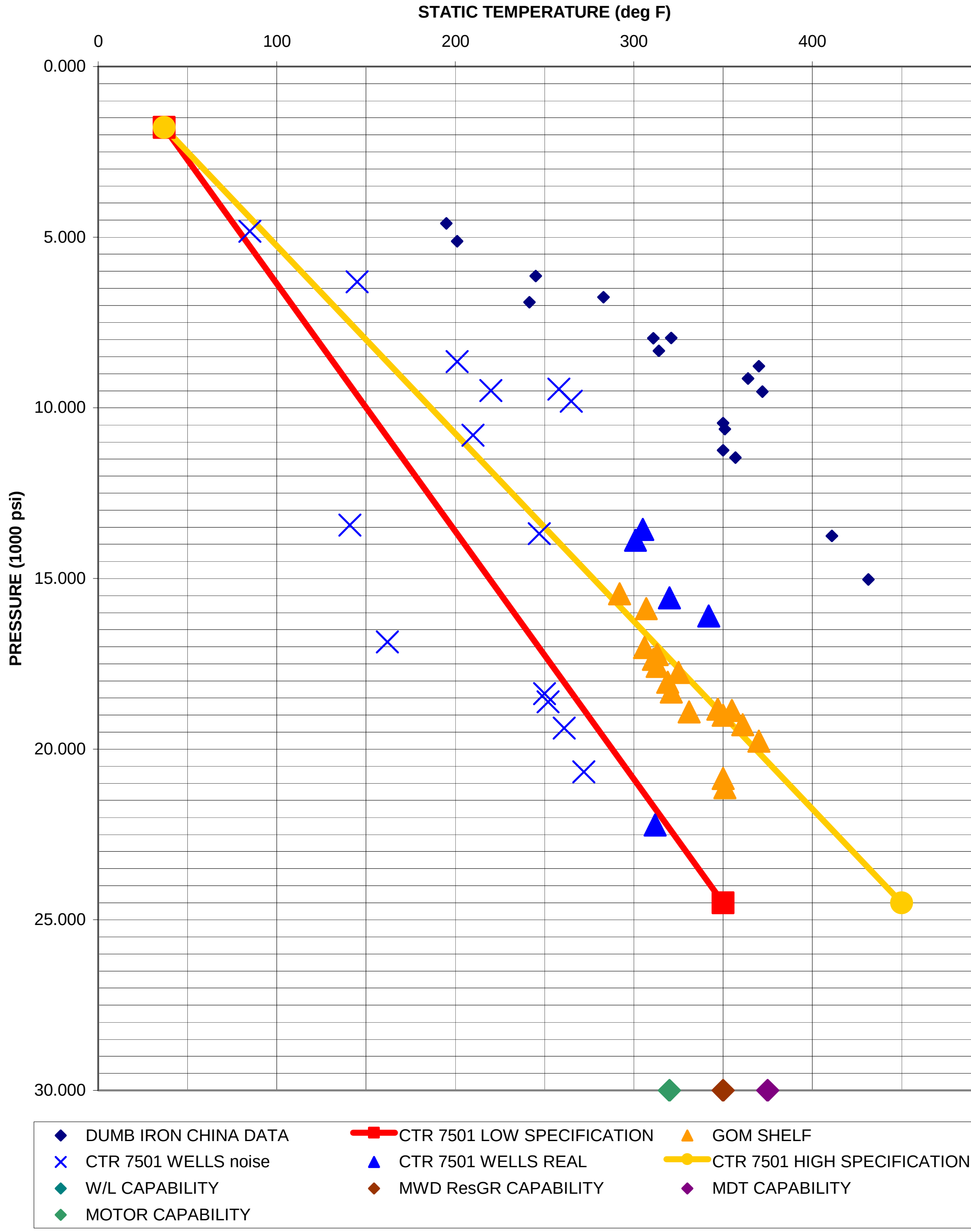
We identified what we consider to be real technology gaps in HPHT drilling involving combinations of electronics, moving parts, power sources, seal technology, elastomers in general, and acceleration or shock loading. In practice, that means that surveying and guiding a well path in real time are problematic activities and that the focus on breaking through existing technology gaps must be directed toward those areas. LWD and MWD are weak links that are only now becoming highly stressed in deep water.

This study includes analysis of 31 deepwater wells, mostly in the GOM and four deep shelf wells in the GOM. The deepwater wells are a combination of wells Triton has worked on in the past and wells contributed by several of the participant companies in CTR 7501 (see Section 2.2). Six of the deepwater wells encountered temperatures greater than 300°F at total depth. Most of the other wells were subsalt, and were, thus, in much cooler environments. The four shelf wells were all in temperatures of greater than 300°F, and all featured multiple failures of MWD and LWD equipment and drilling motors.

The shelf data were submerged to an equivalent of 4,000 ft of water depth to facilitate comparison with failures noted in the "hot" deepwater wells. With regard to technology gaps, Figure 4, Figure 5, and Figure 6 clearly tell the tale.

Figure 4 is a cross-plot of temperatures and pressures. The small blue diamonds on the upper right side of the plot are data points from high-temperature wells in China, all drilled with "dumb iron" and no directional control. The large blue X's on the plot represent failures of a smart component—either LWD, MWD, a motor or RSS, or some combination. These were termed "noise" because the failures were probably due to vibration and shock loading, often apparently associated with drilling salt. The blue and orange triangles represent failures of "smart" components in deepwater and shelf wells, respectively. Superimposed on the symbols are bold lines representing the CTR 7501 specified conditions. The red line represents the low condition of 350°F BHST. The yellow line represents the high condition of 450°F BHST. Finally, there are four diamonds on the bottom of the chart at 30,000 psi. These represent, in increasing order, the current public claims made by vendors for motors (320°F), MWD and Resistivity GR LWD (350°F), MDT Sapphire Gauge pressure measurement capability (375°F), and wireline sonde capability (500°F).

Figure 4. Temperature and Pressure Conditions in HPHT Wells



Failure data from the deepwater and shelf wells clearly demonstrate that "smart" failures are likely to occur above 300°F, or 50°F cooler than the "low" DeepStar CTR 7501 specification for temperature. **That is a huge technology gap.** The gap must be closed to avoid costly alternatives discussed below.

Figure 5 displays the same well data with temperature versus depth. The good news here is that temperature-related failures occur above the CTR 7501 "high" specification for temperature. The bad news is that the good news is irrelevant because the gap between the onset of smart failures and the CTR 7501 specifications is still 50–150°F. We can conclude here that the immediate goal is to increase smart component reliability 50°F, with a longer term goal of increasing reliability 150°F.

Figure 5. Temperature versus Depth for HPHT Wells

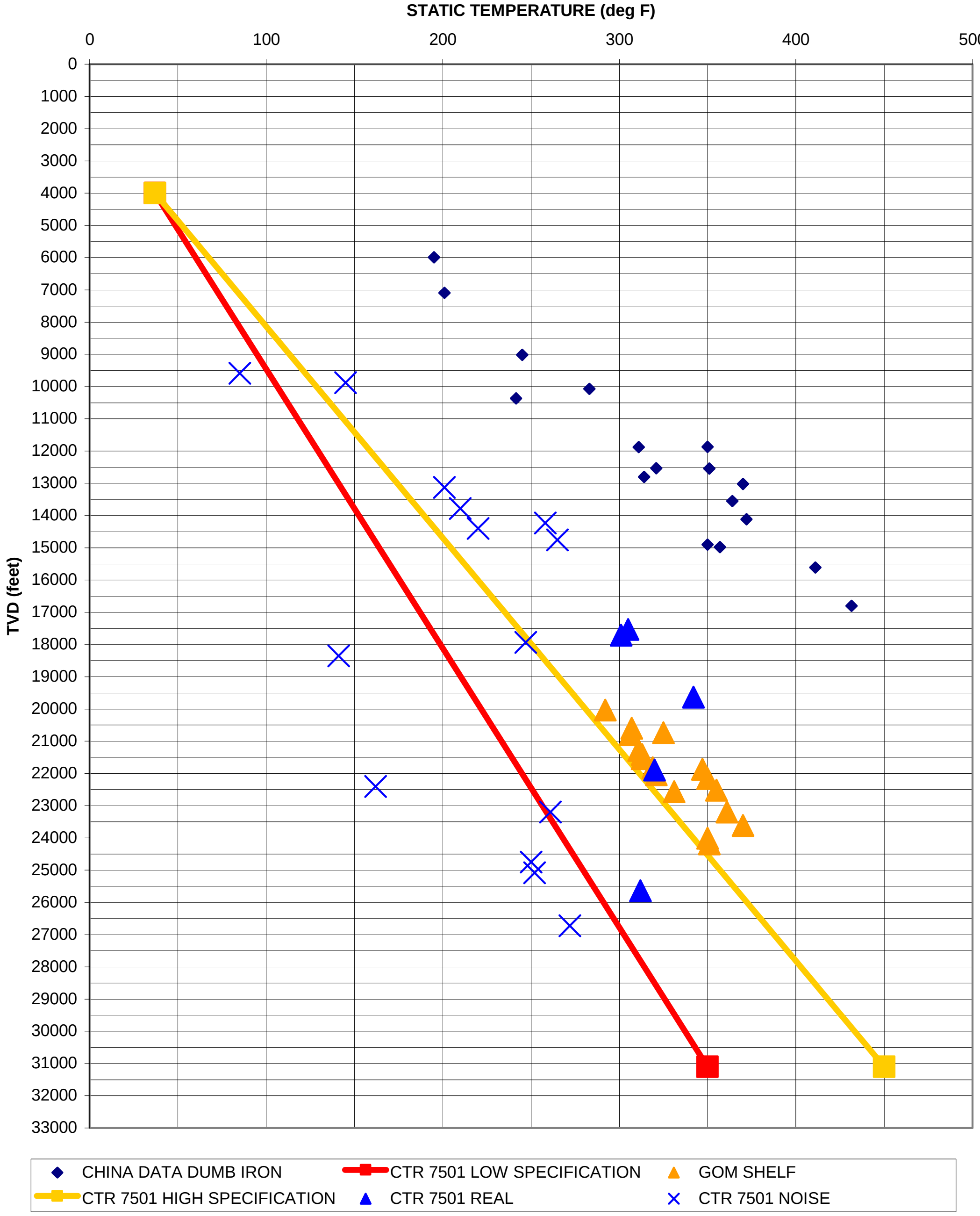
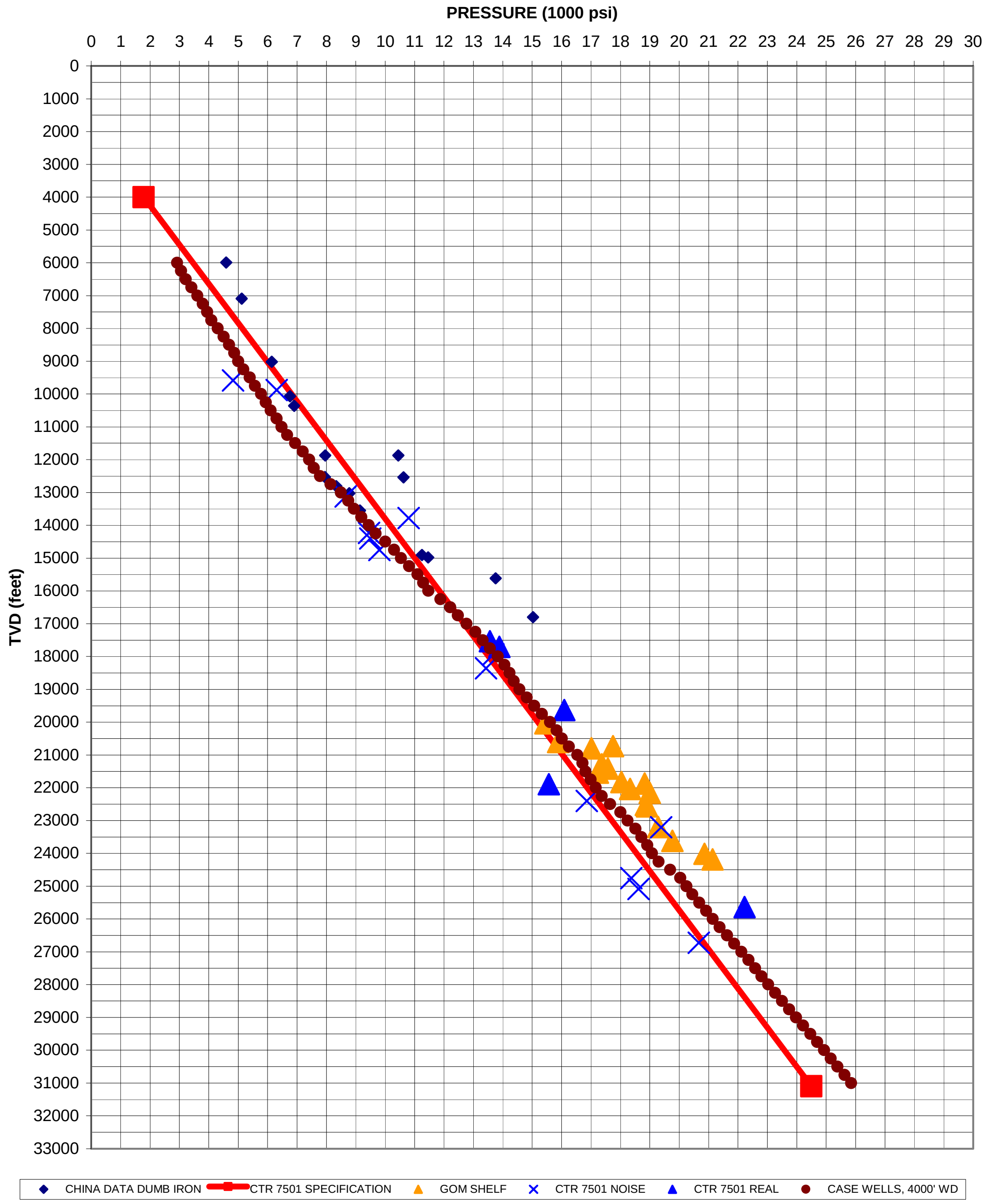


Figure 6 shows the same well data with pressure versus depth. The maroon squares represent average mud pressure from the four case wells in 4,000 ft of water. Clearly, the available smart technology is better able to withstand pressure than temperature. We found almost no instances of pressure-induced failures, and those we did find were from subsalt wells for which we were unable to obtain temperature data. The wells must have been cool, however. We also know that smart tools are successfully operating at pressures in excess of 25,000 psi, although we only have anecdotal evidence of this at this time.

Figure 6. Pressure versus Depth for HPHT Wells



3.4 Analysis of Industry Survey

Based on the survey of industry service providers, an individual assessment for each of the selected service lines was developed. Table 5 (on page 24) gives an overall risk comparison of selected well drivers on well design.

3.4.1 Wellhead & Casing Hanger

Requirement: Serves as a means to hang-off casing and also attach BOPs and subsea trees to maintain well control. BOPs and subsea trees are out of scope and addressed in HIPPS.

1) Identify physical design parameters in the objective environment.
    - Cost – Tooling cost, maintainability, and manufacturability
    - Equipment Limits – Pressure, temperature, service, injection and control lines
    - Size – ID, bowls

2) Identify impact of selected drivers on well design.
    - Equipment Limits – (High) – Determines pressure, temperature and service limitations for production. Sealing is critical. Injection and control line feed-through are also important.
    - Cost (Medium) – In line with other well equipment
    - Size (Medium) – Determines number and size of casing strings that can be run.

3) Define limits of current technology vis-à-vis DeepStar requirements:
    - Cost – Maintainability is a major issue from a cost and safety perspective, although it is adequate for current systems. Manufacturability determines equipment cost which is expensive although not necessarily a limiting factor.
    - Equipment Limits – Current ratings are 15,000 psi with sour gas service to 350°F. Metal-to-metal seals with elastomer back-up seals are currently used; this combination has reached its operational threshold.
    - Size – Based on the scenarios provided, five to six bowls should be adequate as well as casing sizes currently used.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Initial cost estimates to develop wellheads for this environment are in the range of $2 to $3 million. Dual metal sealing will also be required.
    - Cost – While costs will be substantially more, they should be proportional to other drilling project costs.
    - Equipment Limits – Designs to 25,000 psi and 450°F will be required

3.4.2 Drilling Fluids

Requirements: Maintains well control, cools the drilling bit, serves as lubrication, removes formation cuttings and prevents sloughing with minimal damage to the formation.

1) Identify physical design parameters in the objective environment.
    - Storage and Mixing – Volumetric requirements, types of mixing equipment
    - Hole Stability – Formation type, pore pressure, frac gradient, lost circulation control, filter cake
    - Cutting Removal – Transport properties, conditioning, removal
    - Fluid Stability – Pressure, temperature, barite sag resistance, contamination removal
    - ECD Management – Pressure, density, rheology, surge/swab pressure, pore pressure, frac gradient
    - Testing Equipment – Rheology, filter cake, and fluid loss
    - HSE – Disposal, toxicity, treatment of cuttings
    - Drilling Performance – ROP, drag, stuck pipe

2) Identify impact of selected drivers on well design.
    - Drilling Performance (High) – ROP, stuck pipe and twisting off
    - Hole Stability (High) – Pore pressure near frac gradient. Mud loss and circulation loss are also issues.

- Fluid Stability (High) – Determines ECD, barite sag resistance, H_2S and CO_2 solubility, well control in general
- Testing Equipment (High)– Equipment used to evaluate drilling fluid properties at well conditions
- Formation Type (Medium) – Formation damage, rock mechanics
- Cutting Removal (Medium)– Related to fluid properties and pump rate
- HSE (Medium) – Handling, transport, disposal
- Storage and Mixing (Low) – Tanks, piping, blenders

3) Define limits of current technology vis-à-vis DeepStar requirements:
   - Storage and Mixing – Existing drilling fluid storage and mixing technology is adequate for both the 400°F and 500°F scenarios.
   - Hole Stability – Managing ECD, sloughing, and hole ballooning are marginally handled in this environment.

4) Identify necessary gap closures prior to drilling DeepStar wells
   - Formation Type – Wells are currently drilled to 25,000 ft below the mud line in deep water with reasonable success. Limits at 30,000 ft below the mud line and possible formation damage are unknown at this time.
   - Cutting Removal – Existing mud systems adequately remove drill cuttings. Current shale shaker technology is also satisfactory.
   - Fluid Stability – Water-based mud realistically works to 425°F while oil and synthetic mud is stable up to 500°F. Drilling in HPHT formations are 10% of normal drilling conditions; improvements in fluid properties and drilling bit technology could substantially improve ROP.
   - Test Equipment – Rheology equipment is being developed to work at 600°F.
   - HSE – Disposal, toxicity, and treatment of cuttings are adequately handled. Mud cooling has been added to safely handle pipe and to reduce LWD/MWD tool temperature.
   - Drilling Performance – Research is being conducted to determine mud conditions to improve drilling performance.

3.4.3 LWD/MWD

Requirements: Measure downhole formation and well characteristics. Transmit information to the surface via telemetry for improved decision-making capabilities.

1) Identify physical design parameters in the targeted environment.
   - Measurements – Formation, well bore parameters, well fluid parameters
   - Equipment limits – Pressure, temperature, power, vibration
   - Cost – Tool cost, maintainability
   - Manufacturability – Selection process, limited quantity runs.
   - Hole size – Tool OD, run rate
   - Telemetry – Speed, interface
   - Power – Type, current, life

2) Identify impact of drivers on well design.
   - Measurements (High) – Accuracy, drift, repeatability, and reliability.
   - Equipment Limits (High) – Pressure, temperature, service vibration.
   - Cost (High) – Small quantity ASICs are costly.

- Manufacturability (High) – Chips have to be manufactured and depend on quantity ordered.
- Telemetry (High) – Information must be transmitted from downhole tool string to the surface.
- Power (High) – Required to operate tools while running in and out of the hole.
- Hole Size (Medium) – Tool diameter must allow them to run in and out of the hole.
- Storage and Transport (Medium) – Skids, radioactive material, batteries.

3) Define limits of current technology vis-à-vis DeepStar requirements.
   - Measurements – Electronics for sensing and processing in downhole applications work reliably to 275°F and function up to 350°F with an exponential failure rate above 275°F.
   - Equipment Limits – Sealing is a major issue. Double sealing techniques are typically used to prevent leaks.
   - Cost – Electronic components for this environment are expensive, if they exist. Two projects are currently underway to address this issue.
   - Manufacturability – See *Cost*.
   - Hole Size – Tool sizes are available for most well conditions. Casing/well programs need to be defined before making a determination.
   - Telemetry– Current data transmission methods are limited to 20,000 ft and 350°F. Operators are also requesting real-time service. Intelligent pipe is being tested and could provide a solution. A project on low frequency transmission is also underway.
   - Power – Turbines are adequate for current conditions. Batteries are limited to 350°F for lithium thynol chloride and 400°F for mercury.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - Measurements – Extend the existing electronic projects to 500°F.
   - Equipment Limits – Sealing is a major issue and double sealing techniques are typically used to prevent leaks. Improved sealing will be required for 30,000 psi and 500°F.
   - Telemetry – A solution is needed for 30,000 ft and real-time service.
   - Power – Major improvements in both turbines and battery technology will be required.

3.4.4 Openhole Logging

Requirement: Measure formation and well characteristics by introducing a suite of tools in the well that convert electrical and radioactive parameters into meaningful data.

1) Identify physical design parameters in specified environment.
   - Tool string conveyance – Methods, reliability, pull strength, rate, well conditions
   - Measurements – Formation, well bore parameters, well fluid parameters
   - Equipment Limits – Pressure, temperature
   - Hole Size – Tool OD, run rate
   - Telemetry – Speed, interfaces

2) Identify impact of those drivers on well design.
   - Measurements (High) – Sensors are needed to evaluate the well.
   - Equipment (High) – Protecting electronics and sensors from well conditions is essential.
   - Tool string Conveyance (Medium) – Getting tool suites to TD is paramount to well evaluation.
   - Hole Size (Low) – Not a factor at this time.
   - Telemetry (Low) – Data transmission rates are adequate.

3) Define limits of current technology vis-à-vis DeepStar requirements:
    - Tool string Conveyance – Special line and line cutting devices have been developed to run electric line in deepwater, HPHT wells. Service companies are experienced logging to 32,600 ft on the shelf ;and in deep water, to depths of 10,000 ft. For deviated situations, drill pipe conveyed systems are available.
    - Equipment limits– Current limitations are 25 kpsi and 450°F. See LWD/MWD for electronic requirements.
    - Measurements – See LWD/MWD. Most sensors are available for 400°F service. Resistivity, density, neutron, dipole, and sonic are available to 450°F.
    - Hole size – Current equipment is available to 2¾" OD.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Develop sensors and electronics to operate at 500°F.

3.4.5 Directional Drilling

Requirement: Provide reliable information on bit location and drilling angle from downhole to the surface thereby allowing the operator to steer the bit in the desired location. Low-cost systems are being requested by operators.

1) Identify physical design parameters in the objective environment.
    - Storage and Transport – Skids, mounting, spares.
    - Drilling Equipment and Stabilizers – Pressure, temperature, tensile loading, torque rating, method and range of operation.
    - Electronics – Temperature, vibration, power.
    - Drilling Motors – Type, reliability, rpm, seals, bearings.
    - Telemetry – Transfer speed, relay equipment, method.
    - Pressure Drop – Motor type, design, flow rate.
    - Vibration – Bits, damping.

2) Identify impact of those drivers on well design.
    - Size (High) – Tool diameter, length, connections, flow rate.
    - Steering (High) – Build rate.
    - Strength (High) – Overpull, torque, WOB.
    - Electronics (High) – See *LWD/MWD*.
    - Drilling Motors (High) – Determine ROP through RPM and torque.
    - Telemetry (High) – Required for controlling steering. See *LWD/MWD*.
    - LCM Size (High) – Plugging.
    - Power (High) – See *LWD/MWD*.
    - Vibration (High) – Affects tool reliability.
    - Pressure Drop (Medium) – Determines flow rate.
    - Storage and Transport (Low) – Skids, cases.

3) Define limits of current technology vis-à-vis DeepStar requirements.
    - Storage and Transport – Currently not an issue.
    - Drilling Equipment and Stabilizers – Current technology is expensive and at (or near) operational limits. Operators have reported 6–8 failures while drilling the production section.
    - Electronics – One of the major issues (addressed in LWD/MWD Section 3.4.3)

- Drilling Motors – Recently turbines have been introduced that are more reliable than their predecessors. These have improved ROP substantially. Moyno style motors are also being improved by replacing rubber liners with tight- tolerance impellers to increase performance. Current equipment could be stretched to its limit at the higher end of DeepStar requirements.
- Telemetry – Limited to 20,000 ft and 350°F. Data rates are relatively slow and real-time is required for decision-making. See LWD/MWD Section 3.4.3.
- Pressure Drop – Pressure drop is an issue, although minor in comparison to other challenges presented by HPHT wells.
- Vibration – Better bit design and analysis of harmonics could reduce the problem. This is one of the contributing factors in equipment failures.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Equipment – Electronics and telemetry are addressed in LWD/MWD.
    - Lower cost and reliable systems are needed to improve drilling performance.
    - Drilling Motors – Turbine and bearing improvements are necessary to reach 30,000 psi and 500°F. Moyno upgrades are also required.
    - Vibration – Addressed in the drill bits section.

3.4.6 Drill Bits and Cutters

Requirement: Remove formation material efficiently and economically to create a wellbore suitable for hydrocarbon production.

1) Identify physical design parameters in the targeted environment.
    - Types – Roller, PDC, TSP, impregnated
    - Formation – Type, porosity, compressive strength, shear strength
    - Size Availability – Casing size, weight
    - Design Limits – Pressure, temperature, WOB, torque, vibration
    - Jet Size – Lubrication, cooling, cutting efficiency

2) Identify impact of those drivers on well design.
    - Types – (High) Bit type determines penetration rate and longevity.
    - Formation – (High) HPHT environments have higher compressive and shear strength compared to normal formations. As a result, thousandths-of-an-inch are removed per bit rotation versus hundredths-of-an-inch in normal drilling conditions.
    - Size Availability (High) – Casing programs determine bit size. Using the correct bit determines the next size casing that can be set.
    - Design Limits (High) – Cutter technology and patterns determine ROP. Vibration is also an issue since it affects other equipment in the hole.
    - Jet Size (Medium) – See *Design Limits*.

3) Define limits of current technology vis-à-vis DeepStar requirements.
    - Types – Manufacturers are combining cutter types in various patterns to achieve optimum performance. A DOE industry project investigating drill bit/drilling fluid combinations to achieve optimum drilling performance is underway. Also, a project is in progress to develop a cutter that will improve ROP. A new and improved cutter will be introduced in several months.
    - Formation – Drill motor and bit configurations can be altered to achieve optimum drilling conditions. Turbines with PDC/TSP bits are currently the preferred method for drilling GOM HPHT wells and have improved drilling performance.

- Size Availability – Suppliers are reluctant to build on speculation because of low volumes for casing sizes and weights used in HPHT environments.
- Design Limits – Currently, there are no design limits. Project wells requiring higher criteria could present design problems from a temperature/metallurgy perspective. Energy balance has improved bit performance and reduced vibration. Techniques are available to reduce vibration by optimizing drilling equipment location.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Types – Continue work on cutter performance improvements. Roller cone bit bearings can be developed for HPHT environments at a cost of $2 to $3 million. Extremely tight tolerance machining will replace seals.
    - Size Availability – Standardizing drilling programs could make it more attractive for bit manufacturers to build equipment for this environment. Custom built equipment adds to cost and limits availability.
    - Vibration – Continue to reduce vibration including energy balance and drillstring equipment optimization.

3.4.7 Inspection, Quality Control and Development of Standards

Requirement: Determine if design, manufacturing and installation of equipment meets a minimum set of standards. Identify current standards that are applicable for deepwater HPHT.

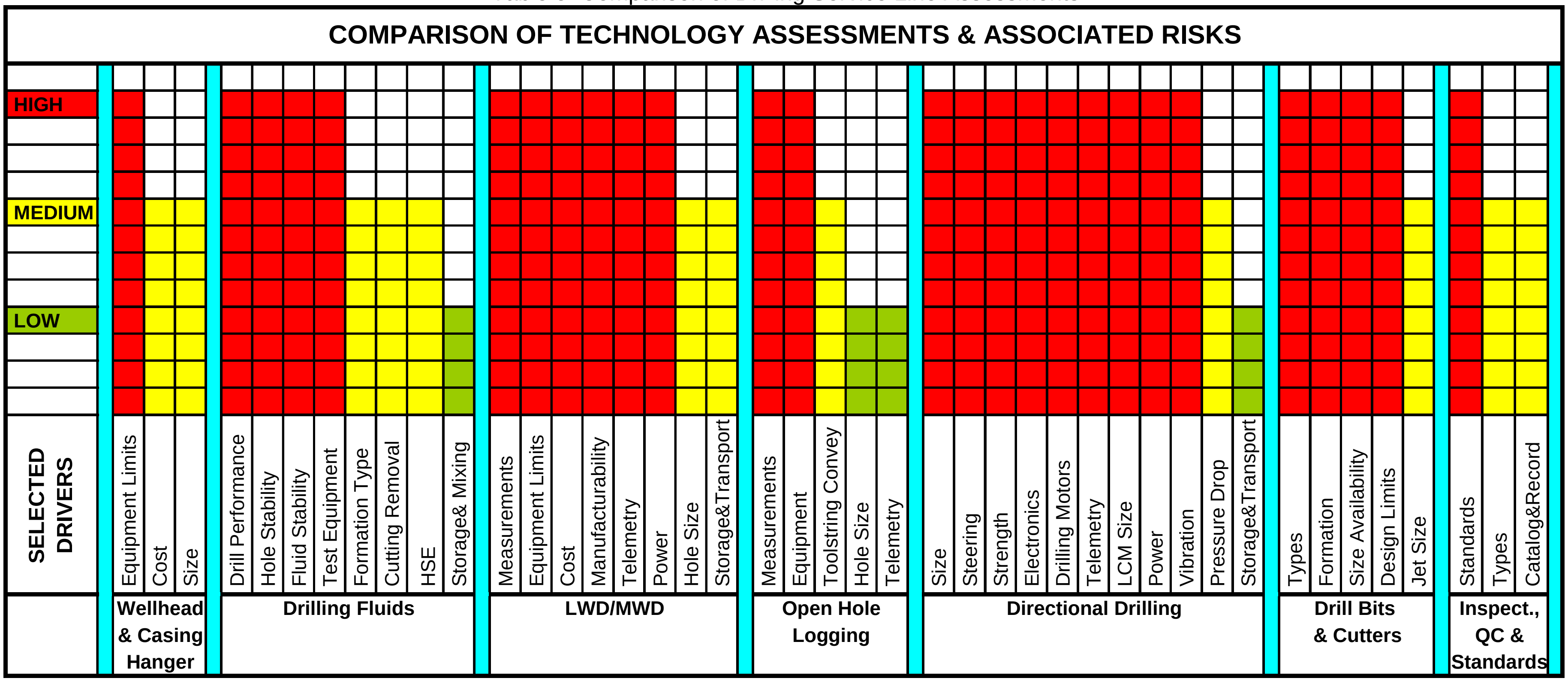
1) Identify physical design parameters in the target environment.
    - Types – Mag particle, ultrasonic, pressure, temperature, vibration, x-ray.
    - Cataloging and Recording – Databases, identification, reporting.
    - Standards – API, NACE, ASME, IEEE.

2) Identify impact of those drivers on well design.
    - Standards (High) – Defines minimum acceptable design or service levels that ensure safe and secure operating limits for equipment and services.
    - Types (Medium) – Mag particle, ultrasonic and x-rays are used to identify non-conformities in metal goods and products. Pressure and temperature testing measure the integrity of equipment. Vibration testing is used to validate electronic system suitability for LWD/MWD/
    - Cataloging and Recording – (Medium) Databases keep and retrieve records thereby identifying usage, service history, and maintenance history.

3) Define limits of current technology vis-à-vis DeepStar requirements.
    - Types – Mag particle, ultrasonic and x-ray have no known limits for this environment.
    - Cataloging and Reporting – Systems are currently being developed.
    - Standards – API Standards will have to be updated, particularly those for subsea wellheads working at 25 kpsi pressure. NACE requirements do not exceed 400°F.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Types – None are known at this time.
    - Cataloging and Reporting – Currently being driven by industry groups.
    - Standards – Update API Standards for wellheads at 25 kpsi working pressure. Develop NACE standards to 500°F.

Table 5. Comparison of Drilling Service Line Assessments



3.5 The "Prize"

The prize associated with closing HPHT drilling technology gaps is money saved by avoiding methods and operations that are unnecessarily slow and cumbersome. **The industry's problem is the reliability of smart components that allow us to survey and measure in real time.** Most probably, there will be no regulatory waivers allowed for drilling wells wherever they might meander in the subsurface in the absence of positive control. Even if regulatory waivers were granted, wells must be located in relation to geological data or the entire basis for exploration and development plans becomes seriously compromised. Risk vanishes because no one knows what the chances are, and uncertainty becomes dominant. LWD and MWD are real-time tools to convert uncertainty to risk. Risk can be managed; uncertainty cannot.

LWD and MWD are the preferred methods for assessing the state of a wellbore. The extreme alternative—drilling ahead blindly—is largely unacceptable. Intermediate alternatives include dropping heat-shielded single-shot instruments at least every 500 ft, tripping for wireline-sonde logging and surveying, and running a miniature tool string inside drill pipe that is not moving. Leaving the drill string still for a long time interval is not an acceptable option due to the mechanical risk of sticking pipe. Dropping a single shot entails the possibility that the instrument will fail in temperature, may get stuck in the drill string (forcing a trip), or may coincide with another event, and limit or complicate options for handling the event, such as well flow or stuck pipe.

In all probability, logging every 500 ft on a planned vertical borehole would be a viable alternative in an exploratory situation. Direction can be maintained vertically by the judicious placement of dumb iron stabilizers. Assuming casing is set at 21,000 ft on a planned 31,000 ft well and the temperature is above 300°F at 21,000 ft, the possibility exists for 19 trips for intermediate logging and surveying. Four of those trips would be for bit changes, 15 would be needed for surveying and there would also be a survey run on each bit change. Fifteen survey trips from an average depth of 26,000 ft at 695 ft/hr would consume about 23.4 days. Assuming an average cost per day of $624.5k, incremental rig and spread cost would be about $14,600k. To that total, the logging cost for 19 runs must be added. Assuming a cost of $250k per run on average (accurate quotations could be obtained) adds almost $5,000k, for a grand total of $20,000k per well, or about 1.25 times the well cost if conventional LWD is used and performs reliably. If the industry drills 10 wells per year, this cost would be near $200,000k. That total would fund significant R&D work.

It is more likely that companies will run MWD and LWD tools and run them to destruction. For the four shelf wells, the average vertical interval between smart failures at temperatures in excess of 300°F was 729 ft, with a range of 177 to 2,724 ft. These tools were run in maximum temperatures of 370°F, so the tools apparently will work at such extreme conditions. Continuous circulation has the potential to keep tool temperatures below the rated limit of 350°F. However, their reliability is in question whenever circulation stops and basic tool temperature increases in response to the static conditions in the well. An interval of 729 ft with some relogging of intervals due to tool failures would entail about 14 trips for a total time of about 21.8 days and an associated cost of about $13,600k. Thus, it is clear that about $6,400k is the expected savings for running smart tools (with their inherent unreliability) as compared to the alternative of tripping to wireline log every 500 ft. Again, assuming 10 wells are drilled per year, the expected total cost of LWD unreliability is about $136,000k, a savings of $64,000k over the trip and wireline option. This level of savings would also fund very large R&D programs.

4. Cementing Assessment

4.1 Analysis Method

To attain the deliverables for this project, the following steps were taken for each of the four cementing sub-categories: Primary, Squeeze, Tieback, and Plug.

- Identify physical design drivers
- Identify the impact of those drivers on well design
- Define current and state-of-the-art technology for meeting DeepStar objectives
- Define limits of existing skills, equipment, and services
- Identify gap-closure requirements
- Quantify time, cost, and technical complexity required to close gaps

4.2 Assessment of Cementing Technology

Cementing in offshore, deepwater wells is a complex operation compared to traditional cementing operations on the shelf and land.[3] Specialized equipment, materials, and well planning complicate the entire drilling process including the cementing operation. Issues listed in each section that follows summarize the major challenges facing deepwater operators when drilling an HPHT well. Table 10 (on page 35) presents an overall risk comparison of selected well drivers on well cementing.

4.2.1 Primary Cementing

Requirements: Provide isolation of zones and well integrity from conductor pipe all the way down to TD.

1) Identify physical design parameters in the objective environment.

<u>Small Annulus in Deep Wellbore</u>

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

<u>Hot, High Pressure Environment</u>

- Accurate temperature prediction for cement job, particularly in deepwater
- Long placement times
- Cement retrogression and instability at high temperatures

<u>Cement/Sealant Long-term Integrity in HPHT Environment with H_2S and CO_2 Present</u>

- Corrosion issues
- Material selection

<u>Multiple Targets Possible but Very Difficult to Achieve</u>

- Narrow pore pressure-fracture gradient window
- Lost circulation
- Wellbore stability/hole collapse issues
- Cross flows and water flows

[3] Drilling Contract, Feb 2004: “Proper Cementing, Sealing Is Key to Zonal Isolation”

- Tight annular clearance

Intervention/Remediation Difficult or Unlikely

- Pipe/hole size small
- Pressure and temperature too high for some equipment
- Intervention/remediation not economically viable

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

Delta Temp and Delta Pressure Gradients

- Induced stress due to cyclic loading
- Plastic deformation of sealants can occur

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

2) Identify impact of selected drivers on well design.

High Impact Issues

- Sealant Performance Criteria – Fluid and Mechanical Properties, H_2S and CO_2 Stability
  Fluid properties
  a. Pumped into place easily
  b. Gas flow must be controlled; this will be exaggerated in HPHT environment
  c. Pumpable at elevated temperature/pressure
  d. Stable/homogeneous at elevated temperature/pressure
  e. Filtrate loss must be controlled at BHCT
  f. Compatible with all well fluids at BHCT
  g. Limited shrinkage over time
  h. Consider formation damage issues

  Mechanical properties
  a. Adequate strength for long-term structural integrity
  b. Must provide a good shear bond
  c. Low permeability

  H_2S and CO_2 stability
  a. Provide corrosion resistance
  b. Ability to seal and bond for the long-term with H_2S and CO_2 present in the HPHT environment

- Sealant Density Control – Equipment must be capable of mixing high density sealants accurately.
- Hole Stability – Wellbore strengthening/stability products to reach targets
- Bond Logs and Evaluation – Ensure zonal isolation and bond to the formation and the pipe.
- Rheological Model – Accurate computer simulations and rheology measurements that occur in downhole conditions are required in predicting wellbore pressures during cement placement.
- Friction Pressure – Friction pressure should be taken into consideration for all HPHT jobs because very long work strings may be encountered. And as previously stated, annulus clearances will be tight.

Medium Impact Issues

- Design Testing in Lab – Required to verify placement time and that sealant performance criteria will be met.
- Plug and Float Equipment – Rated for anticipated temperature, pressure, flow rate, mud type, and fluid solid content.
- Openhole ECP (Expandable Casing Packer) – Isolates lost circulation zones, controls gas migration and prevents water encroachment into production zones.
- Liner Top Packers – Rated for anticipated temperature, pressure, flow rate, mud type, and fluid solid content.
- Low Density Cements – A low density sealant with the mechanical properties described above may be required in certain sections of the well.

Low Impact Issues

- Expandable Tubular – Often planned as a contingency.
- Conventional Portland Cement – Lacks some of the desired properties required for the HPHT environment.
- Casing Attachments – May be limited by hole size; not available for expanded tubular jobs.

3) Define current and state-of-the-art technology for meeting DeepStar objectives:
    - Friction Pressure – Sophisticated software packages designed to simulate and predict the friction pressure during the job are offered by many service companies. Also, laboratory procedures are being modified to assist with these calculations.
    - Hole Stability – This is an evolving technology, and many products are being introduced in the marketplace including resins, polymers, and specialized drilling fluids.
    - Low Density Cements – Foam cement systems and ceramic bead systems.
    - Bond Logs and Evaluation – Acoustic, Segmented Bond, and Ultrasonic.
    - Plug and Float Equipment – See *API RB-10-F*.
    - Openhole ECP – Several service companies have HPHT ECP’s available.
    - Liner Top Packers – Several service companies have HPHT packers available.

4) Define limits of current technology vis-à-vis the DeepStar requirements.
    - H_2S and CO_2 Issues – Only short-term low pressure tests at 300°F have been run.
    - Sealant Density Control – Current density limit is ±22 lb/gal.
    - Compatibility with Required Well Fluids at BHCT – Currently, there is no standard on how to conduct these tests. Most tests are run at atmospheric pressure and 190° F. API is considering organizing a work group to further study this issue.
    - HT Salt Cement – Some research has been done with salt slurries at elevated temperatures, but the data is somewhat limited.

- Friction Pressure – Many computer models lack the capability to predict the ECD on reverse jobs. Also, accurate rheology numbers at elevated temperatures are difficult to obtain.
- Hole Strengthening/Stability – Polymer Fluid Blends, Membrane Forming Fluids, Solid-free Penetrating Fluids.
  a. Polymer fluid blends are primarily used when severe lost circulation occurs and to also increase the apparent fracture gradient of the well.
  b. The membrane forming fluids also help with lost circulation and enhance the success rate of primary cement jobs.
  c. Solids-free penetrating fluids are used to consolidate formations thereby preventing hole collapse. Pressure limit 25 kpsi; temperature limit 350°F.
- Mechanical Properties – It is possible to achieve classic desired mechanical properties; however, it may be quite challenging in the HPHT environment to achieve properties which will minimize the long-term effects of anelastric strain.
- Rheological Model – Limited to 190°F. HPHT rheometer currently in development.
- Bond Logs and Evaluation – CBL limit is 350°F and 15 kpsi; ultrasonic logging tool limit is 400°F and 15 kpsi.
- Design Testing in Lab – Machines are available for testing up to 50 kpsi and 500°F.
- Plug and Float Equipment – Premium lines are rated for 5 kpsi differential and 400°F.
- Openhole ECP – Practical limit is 20 kpsi and 400°F; elastomer performance decreases significantly beyond 400°F.
- Liner Top Packers - Premium lines are rated for 20 kpsi and 430°F.
- Expandable Tubular – Pressure is limited to 20 kpsi; temperature is limited to 400°F.
- Conventional Portland Cement – Sufficient mechanical properties and long-term durability will be very hard to attain in the HPHT environment.

5) Identify necessary gap closures prior to drilling DeepStar wells.
   - Lab testing at BHST/BHP – Implement a standard, objective, compatibility test format for use with HPHT wells. Also, use verification testing to confirm that preferred mechanical properties and long-term durability are achieved by the sealing material.
   - H_2S and CO_2 – Investigate long-term effects of H_2S and CO_2 at BHST/BHP.
   - Optimizing Sealant Placement – Develop procedures and methods to optimize drilling fluid displacement during cement jobs in HPHT conditions.
   - Bond Logs and Evaluation – Develop sensors and electronics that will operate in temperatures as high as 500°F or develop a cooling system to maintain the electronic component temperature within the current operating range of the existing logging tools.
   - Alternative Sealants – Continue to research and test new products and technologies as they are introduced as replacements for conventional Portland cement.

6) Quantify time, cost, and technical complexity required to close gaps.

Table 6. Time Required to Close Primary Cementing Gaps

Issue	Timeframe	Cost	Technical Complexity
H_2S and CO_2 Issues	18 months	$1,000,000	High
Alternative Sealants	18 months	$1,000,000	High
Lab Testing at BHST/BHP	6 months	$300,000	Medium
Bond Logs	6 months	$300,000	Medium
Optimizing Sealant Placement	18 months	$1,000,000	Low

4.2.2 Squeeze Cementing

Requirements: Remedy the deficiencies of a primary cementing job.

1) Identify physical design parameters in the objective environment.

   Hot, High Pressure Environment

   - Accurate temperature prediction for squeeze job particularly in deepwater.
   - Cement instability at high temperatures.

   Intervention/Remediation Difficult or Unlikely

   - Pipe/hole size small.
   - Pressure and temperature too high for some equipment.
   - Intervention/remediation not economically viable.

   Salt Complications

   - Cement/sealant sheath integrity across salt formations.

   Cement/Sealant Long-term Integrity in HPHT Environment with H_2S and CO_2 Present

   - Corrosion issues

   Pressure Control and Interpretation

   - Correlation between downhole pressure and surface pressure
   - Interpretation of squeeze performance and use of PWD to enhance understanding.

2) Identify impact of selected drivers on well design.

   High Impact Issues

   - Sealant Performance Criteria – Fluid and Mechanical Properties, H_2S and CO_2 Issues

     Fluid properties

     a. Pumpable at elevated temperatures/pressures.
     b. Stable/homogeneous at elevated temperatures/pressures.
     c. Compatible with all well fluids at BHCT.

     Mechanical properties

     a. Develop adequate strength to provide zonal isolation.
     b. Low permeability.

     H_2S and CO_2 issues

     a. Provide corrosion resistance.
     b. Seal/Bond for the long-term with H_2S and CO_2 present in the HPHT environment.

   - Sealant Density Control – Equipment must be capable of mixing high density sealants accurately.

   Medium Impact Issues:

   - Design Testing in Lab – Required to verify optimum placement time and that sealant performance criteria will be met.
   - Squeeze Packer Equipment – Rated for anticipated temperature, pressure, flow rate, and solids content.

3) Define current and state-of-the-art technology for meeting DeepStar objectives.
   - Squeeze Packer Equipment – Several service companies have HPHT packers available.

4) Define limits of current technology vis-à-vis the DeepStar requirements.
   - Sealant Density Control – Current Density limit is ±22 lb/gal.
   - Squeeze Packer Equipment – Premium lines are rated for 12 kpsi differential and 430°F.

5) Identify necessary gap closures prior to drilling DeepStar wells.
   - Lab Testing at BHST/BHP – Implement a standard, objective compatibility test format for use with HPHT wells. Also, implement verification testing to confirm that the sealing material achieves preferred mechanical properties and long-term durability.
   - Alternative Sealants – Continue to research and test new products and technologies as they are introduced as replacements for conventional Portland cement.
   - H_2S and CO_2 – Investigate long-term effects of H_2S and CO_2 at BHST/BHP.

6) Quantify time, cost, and technical complexity required to close gaps.

Table 7. Time Require to Close Squeeze Cementing Gaps

Issue	Timeframe	Cost	Technical Complexity
H_2S and CO_2 Issues	18 months	$1,000,000	High
Alternative Sealants	18 months	$1,000,000	High
Lab Testing at BHST/BHP	6 months	$300,000	Medium

4.2.3 Tieback Cementing

Requirements: Support tieback casing and insure isolation of production zones.

1) Identify physical design parameters in the objective environment.

   Hot, High Pressure Environments
   - Accurate temperature prediction for cement job, particularly in deepwater.
   - Long placement times.
   - Cement retrogression and instability at high temperatures.

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

   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.

2) Identify impact of selected drivers on well design.

   High Impact Issues:
   - Sealant Performance Criteria – Fluid and Mechanical Properties

     Fluid properties

     a. Pumpable at elevated temperature/pressure.
     b. Stable/homogeneous at elevated temperature/pressure.

c. Compatible with well fluids at BHCT.

Mechanical properties

a. Develop adequate strength to provide zonal isolation and casing support.

b. Low permeability.

- Pressure Maintenance – Accurate pressure estimation (between tieback and existing pipe) is required for optimizing tieback designs.
- APB (Annular pressure buildup) In-between Casings – Have mitigation plan in design.
- Bond Logs and Evaluation – Insure cement has bonded to the pipe.

Medium Impact Issues:

- Rheological Model – Not as critical as openhole jobs; needed to predict surface pressures.
- Friction Pressure – Not as critical for tieback jobs because job entails cementing pipe-in-pipe.
- Design Testing in Lab – Required to verify placement time and sealant performance criteria is met.

3) Define current and state-of-the-art technology for meeting DeepStar objectives.
   - Pressure Maintenance – Conventional cement with or without gas generating additive materials.
   - APB In-between Casings – Current technique pumps a foamed spacer ahead of the cement job. Also, technology exists to create VIT (Vacuum insulated tubing).

4) Define limits of current technology vis-à-vis the DeepStar requirements.
   - Pressure Maintenance – Current sealant limit is 25 kpsi and 400°F.
   - APB In-between Casings – Research is currently being conducted to help the industry understand and implement different methods to control these thermal expansion issues.
   - Bond Logs and Evaluation – CBL limit is 350°F and 15 kpsi; Ultrasonic logging tool limit is 400°F and 15 kpsi.

5) Identify necessary gap closures prior to drilling DeepStar wells.
   - Annular Pressure In-between Casings – Continue research to insure we have a better understanding of how we can handle these issues.
   - Bond Logs and Evaluation – Develop sensors and electronics to operate in temperatures as high as 500°F or develop a cooling system which will maintain the electronic component temperature within the current operating range of the existing logging tools.
   - Pressure Maintenance – Research application of alternative sealants for tieback jobs to better define optimization techniques.

6) Quantify time, cost, and technical complexity required to close gaps.

Table 8. Time Required to Close Tieback Cementing Gaps

Issue	Timeframe	Cost	Technical Complexity
APB In-between Casings	18 months	$1,000,000	High
Pressure Maintenance	12 months	$600,000	High
Bond Logs	6 months	$300,000	Medium

4.2.4 Plug Cementing

Requirements: Provides isolation from an abandoned well, supplies sufficient compressive strength for obtaining a successful kickoff for a sidetrack/bypasses well, and remedies problems associated with lost circulation.

1) Identify physical design parameters in the objective environment.

Hot, High Pressure Environment

- Accurate temperature prediction for cement job, particularly in deepwater.
- Long placement times.
- Cement retrogression and instability at high temperatures.

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.

Cement/Sealant Long-term Integrity in HPHT Environment with H_2S and CO_2 Present

- Corrosion issues
- Material selection

Cement/Sealant Strength and Seal Capabilities

- Contamination issues.
- Accurate displacement.
- Solutions for lost circulation and wellbore strengthening/stability.
- Successful kickoff in ultra deep well.

2) Identify impact of selected drivers on well design.

High Impact Issues

- Sealant Performance Criteria – Fluid and Mechanical Properties, H_2S and CO_2 Stability.
  Fluid properties
  a. Pumpable at elevated temperature/pressure.
  b. Stable/homogeneous at elevated temperature/pressure.
  c. Compatible with well fluids at BHCT.

  Mechanical properties
  a. Sufficient tensile and compressive strength to insure successful isolation and the ability to kickoff.

  H_2S and CO_2 issues
  a. Meet requirements stated in *API RP 49* for abandonment plugs.
  b. Maintain seal integrity for the long-term.
- Hole Strengthening/Stability – Cement/Sealant may be used to create a "virtual casing", thereby eliminating one or more casing strings.
- Sealant Contamination – Must be minimized.
- Displacement Accuracy – Must be maximized.

Medium Impact Issues

- Design Testing in Lab – Required to verify sealant performance criteria will be met.
- Rheological Model – YP is somewhat critical for plug jobs.

Low Impact Issues

- Friction Pressure – Not critical for plug jobs.

3) Define current and state-of-the-art technology for meeting DeepStar objectives.
    - Plug Catchers – Reduces contamination and maximizes accuracy.
    - Tubing release tool – Minimizes contamination and maximizes accuracy. Tubing is left in the well after being released by a ball-catching mechanism.
    - Diverter Sub – Aides with mud removal downhole.
    - Kickoff Plug in Ultra deep well – Class H Cement with Silica or Sand.
    - Hole Strengthening/Stability – This is an evolving technology and there are many products being introduced into the market including resins, polymers, and specialized drilling fluids.

4) Define limits of current technology vis-à-vis DeepStar requirements.
    - Plug Catchers – Limit is 20 kpsi and 400°F.
    - Tubing Release Tool – Current tool is rated to 20 kpsi and 400°F.
    - Diverter Sub – Limit not applicable.
    - Kickoff Plug in Ultra Deep Well – 5 kpsi compressive strength.
    - Hole Strengthening/Stability – Polymer Fluid Blends, Membrane Forming Fluids, Solid-free Penetrating Fluids.
        a. Polymer fluid blends are primarily used when severe lost circulation occurs and to also increase the apparent fracture gradient of the well.
        b. The membrane forming fluids also help with lost circulation and enhance the success rate of primary cement jobs.
        c. Solid-free penetrating fluids are used to consolidate formations thereby preventing hole collapse. Pressure limit 25 kpsi; temperature limit 350°F.

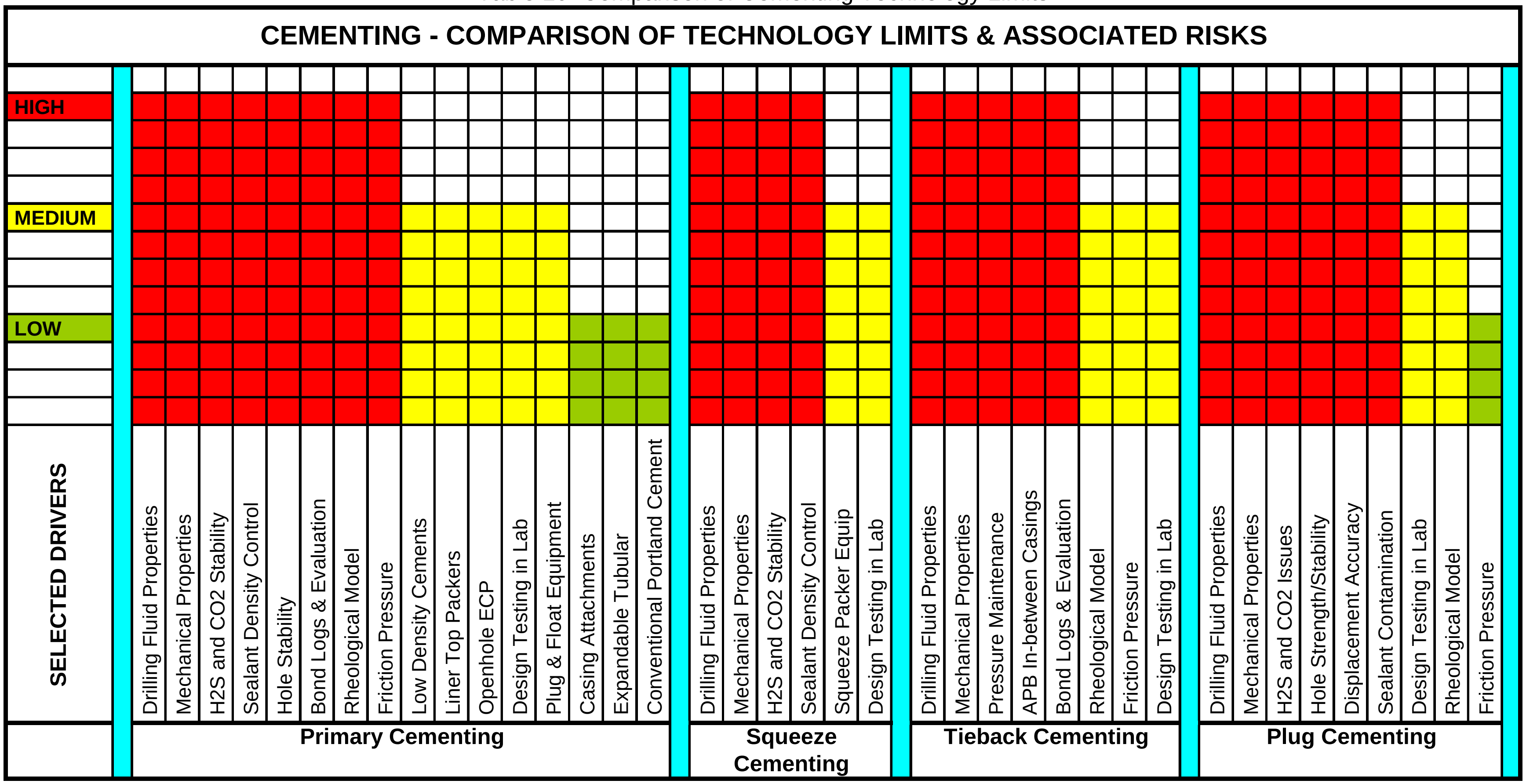
5) Identify necessary gap closures prior to drilling DeepStar wells.
    - Lab Testing at BHST/BHP – Implement a standard, objective compatibility test format for use with HPHT wells. Also, implement verification testing which will confirm that the sealing material achieves preferred mechanical properties and long-term durability.
    - Alternative Sealants – Continue researching and testing as new products and technologies continue to be introduced to the industry as a replacement for conventional Portland cement.
    - Kick-off Plug in Ultra Deep Well - Research current kick off plug materials and alternative materials in order to maximize strengths and insure successful sidetracks in ultra deep wells.
    - H_2S and CO_2 – Investigate long-term effects of H_2S and CO_2 at BHST/BHP.

6) Quantify time, cost, and technical complexity required to close gaps.

Table 9. Time Required to Close Plug Cementing Gaps

Issue	Timeframe	Cost	Technical Complexity
H_2S and CO_2 Issues	18 months	$1,000,000	High
Alternative Sealants	18 months	$1,000,000	High
Lab Testing at BHST/BHP	6 months	$300,000	Medium
Kickoff Plug in Ultra Deep Well	6 months	$300,000	Medium

Table 10. Comparison of Cementing Technology Limits



5. Completion Assessment

5.1 Issues for HPHT Completions

Challenges of completing deep HPHT wells are significant. New 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 hole.[4]

Acid gases, H_2S and CO_2, have severe cracking and weight-loss consequences when encountered in significant concentrations. H_2S 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.

Wellhead equipment is subject to pressure derating in service above 300°F and shares problems associated with accelerated corrosion of tubulars. Wellheads and trees have successfully used CRAs to maintain seal integrity. Cladding techniques (weld clad, HIP) have evolved to the state that entire valve bodies can be protected from the producing environment by a thin layer of CRA material applied to the valve's inside surface. Again, a definition of the produced fluid will greatly aid in wellhead design considerations.

5.1.1 Flow Assurance / Production Chemistry

- Hydrates formation
- Injection points, pressure, and equipment
- Temperature limitations on chemicals
- Scale
- Paraffin

5.1.2 Completion Fluids

- Expansion and contraction due to temperature fluctuations
- Corrosivity and handling safety
- Density limits to 20 lb/gallon
- Non-damaging
- Low fluid loss

5.1.3 Completion Equipment

- Limited availability of equipment designed for service conditions
- Dynamic sealing is an issue
- Smartwell technology is only functional to 275°F
- Testing facilities are needed
- Static sealing is an issue at 500°F

[4] Bob Moe and Carl Johnson, Oil Technology Services, Inc.: "How HPHT Completions Differ from the Norm," *World Oil,* Jan 2001, Vol. 222 No. 1.

5.1.4 Perforating

- Charge chemistry to 500°F
- Improvements in case design
- Sealing is an issue at 500°F
- Transmitting pressure to fire TCP guns in mud is difficult

5.1.5 Stimulation

- Test equipment for XHPHT conditions to evaluate designs
- Wellhead isolation during treating may be required
- Carrier fluids with proppant carrying capacity at 500°F
- Densified carrier fluids to reduce horsepower requirements
- High-strength proppants to withstand closure stresses

5.1.6 Complex Well Completions

- Electronics, power, and flow control equipment that withstand 500°F
- Telemetry that functions at 500°F

5.1.7 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

5.1.8 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

5.1.9 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.

5.1.10 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.

5.1.11 Technology Concerns

The following technology concerns were identified by service companies and operators as the principal completion issues facing drillers operating in HPHT, deepwater environments. The supplied data came principally from service companies. Information from the Department of Energy, the Mineral Management Services agency, and the report's authors augmented the data set.

- Completion Fluids
- Well Testing
- Stimulation
- Flow Assurance/Production Chemistry
- Instrumentation
- Perforating
- Smart Technology and Completion equipment

Table 11. Data Sources for Completion Technology

Baker	Well Dynamics	TerraTek	BJS	Schlumberger	HES	Power Well
Completion Fluids						
						Well Testing & Flowback
			Stimulation	Stimulation	Stimulation	
Flow Assurance						
				Instrumentation		
		Perforating				
Completion Equipment	Smart Technology		Packers Elastomers	Packers Elastomers	Packers Elastomers	
Well Testing				Downhole Equipment Subsea Systems Surface Equipment		

5.2 Analysis Method

To attain the deliverables for this project, the following steps were undertaken:

- Develop interview questions
- Interview service companies
- Identify physical design drivers
- Identify impact of those drivers on well design
- Define current and state-of-the-art technology for meeting the DeepStar objectives
- Define limits of existing skills, equipment, and services
- Identify gap-closure requirements
- Quantify time, cost, and technical complexity required to close gaps

5.3 Completion Technology Limits

Technology limits for HPHT completions are summarized below. Table 14 (on page 46) outlines technology limits, present day issues, and research/development requirements for completions in deepwater HPHT conditions.

5.3.1 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

5.3.2 Stimulation

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

5.3.3 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.

5.3.4 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.

5.3.5 Completion Equipment

- Seal Technology – Current limit for dynamic seals is 400º F.
- 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.

Table 12. Completion Equipment Design Issues

Component	Drivers	Design Issues	Regulatory Issues
Packer Systems	• Rig Cost/time (one trip and interventionless completion technology) • Reduce casing stress caused by packer slips and elements	• Metallurgy selection (downhole environmental conditions are key) • Sealing technologies (static and dynamic) • Packer to tubing interfaces • Combined loading and pressure differential • Interventionless packer setting devices • Reduce casing stress caused by packer slips and elements	• ISO/API Qualifications
Surface Controlled Subsurface Safety Valves	• Reliable well control • OD/ID • Cable bypass for downhole pressure gauges	• Seal technology • Metallurgy selection (downhole environmental conditions are key) • Closure mechanism design • Combined loading and pressure differential • Control line and fluids • Rod piston design	• API Qualifications/ Test Pressure Issues
Flow Control Systems	• Reliable well control • Select packer setting devices • Monobore vs. step down nipple completions	• Seal technology • Metallurgy • Pressure differential	• ISO/API Qualifications

5.3.6 Well Testing

Overview: Rates and pressures while testing HPHT wells are prodigious. Well-control equipment used during drilling is designed to handle reservoir fluids for relatively short periods. During a test, the surface equipment must cope with long flow periods. Where possible, elastomers are replaced by metal-to-metal seals, removing the temperature limitation of test equipment. Surface and subsea equipment are monitored using temperature and pressure sensors that report back to a real-time monitoring system, which initiates the emergency shutdown (ESD) system if limits are breached. In addition, the number of downhole test tools and the number of operations they perform are kept to a minimum.

Because of the extreme conditions, HPHT test planning and equipment selection have to be meticulous, and the personnel performing the tests highly trained. With information from offsets, the first task is to anticipate likely maximum values for several key parameters like shut-in tubing-head pressure and wellhead temperature, downhole temperature and pressure, and flow rate. These maxima are used to select equipment with the necessary operating capabilities. If these capabilities are exceeded, the test must stop or the test objectives be reviewed. In establishing the maxima, attention must be paid to data collection. For example, to acquire the correct data, the test will have a minimum flow period, and the length of this period will then affect temperature of seabed equipment.

Next, individual safety requirements of each component are determined—for example, pressure relief valves and temperature monitors. Then components are considered as part of the whole test system, allowing elimination of any redundant safety devices.

When the equipment package is determined, a piping and instrumentation diagram may be prepared, which specifies all equipment, piping, safety devices, and their operating parameters (above). A rig layout diagram highlights positions of key well test equipment making sure that they interface with existing rig emergency shutdown (ESD) systems and fit into limited space.

Safety checks and analyses are carried out according to API recommendations. Procedures are established for key operations like perforating the well, changing chokes or pressure testing all equipment. Contingency plans are made to cope with a range of possible incidents: downhole leaks or failures, surface leaks, deterioration in the sea state or weather, or the formation of hydrates at surface.

This information is submitted to an independent certifying authority that must approve the plans before the test can proceed. In addition, inspection certificates are checked before each piece of equipment is dispatched offshore. Finally, the certifying authority has to approve the rig up.

Test equipment and operations may be divided into three sections: downhole, subsea and surface.

Downhole Equipment: Sealing off the candidate formation requires a packer. During an HPHT test, differential pressures across the packer may exceed 10,000 psi. For this reason, permanent packers are usually chosen, rather than the retrievable packers used in lower pressure tests. With wireline (or very occasionally drill pipe), the packer is installed complete with a sealbore, and a seal assembly is then run with the test string to seal into the packer. The seal assembly is usually about 40 ft long to allow thermal expansion of the test string as hot reservoir fluid flows.

Perforating with wireline guns is generally avoided during HPHT tests, so tubing-conveyed perforating (TCP) is preferred. Unlike wireline perforating, TCP allows the reservoir to be perforated underbalance and immediately flowed through the test string. Because the guns will spend hours in the well prior to firing, high-temperature explosive is used. In most cases, the TCP guns are run as part of the test string, rather than hung off below the packer. This reduces the time that the explosives spend downhole and allows the guns to be retrieved in case of total failure.

In most HPHT wells, TCP guns are fired using a time-delay, tubing-pressure firing mechanism. Tubing pressure initiates the firing process, but the pressure is then bled down to underbalance pressure. The guns fire after a preset delay, long enough to achieve underbalanced conditions. A secondary firing system is usually included in case the primary system fails.

Although the number of downhole tools is reduced to a minimum, HPHT tests still require a number of components to allow downhole shut-in, pressure testing of the string, reverse circulation to remove hydrocarbons from the string prior to pulling out of hole, and downhole measurement of pressure changes. Sometimes to simplify the test procedure, surface shut-in is substituted for downhole shut-in. However, this introduces wellbore storage—the spring effect of the column of fluid in the well below the surface valve that must be accounted for by data analysis—usually necessitates longer shut-in periods.

In most cases, test tools are operated using annular pressure. The condition of the fluid in the annulus, usually drilling mud, plays a critical factor. High-density, high-solids drilling fluid may plug pressure ports and reduce tool reliability. Solids may also settle, potentially sticking the test string. The effects on heavy, water-base mud of being static in a hot well have been thoroughly investigated in the laboratory and the performance of test tools has been improved to reduce downhole failures. In some cases, the annular fluid is changed to high-density brine, which is solids-free but increases the expense of the test.

Subsea Systems: Like drilling, testing is generally simpler on a jackup than on a semi-submersible. On a jackup, the piping to surface is fixed and the control valves are on deck. For a semi-submersible, a subsea test tree is located in the BOPs on the seabed to allow quick and safe disconnection of the test tubing during testing. Above the tree, there is a conventional riser disconnect mechanism and a riser running to the rig's deck. The choke and kill lines are flexible to compensate for vessel heave.

Surface Equipment: At any time during the test it must be possible to shut in the well. Conventionally, this is carried out using the choke manifold valve. In HPHT well tests, a hydraulic actuator is fitted to the flowline valve of the flowhead, or christmas tree, and a hydraulic isolation valve is installed between the flowhead and the choke manifold. Furthermore, a shut-in valve within the subsea safety tree is linked to the ESD panel.

At the heart of the pressure control equipment is the choke manifold. Although separate from the drilling choke, the test manifold has the same purpose, to reduce fluid pressure, usually to less than 1000 psi. The manifold contains adjustable and fixed chokes. To change one of these—either because a different size is required or because of choke erosion—the path through the choke must be isolated by closing valves on either side of it. When a choke is being changed, conventional four-valve manifolds do not offer the double isolation required for HPHT tests. For this reason, eight-valve manifolds that are nearly twice the size of the four-valve version are often used. In other cases, two four-valve manifolds separated by isolation valves are specified.

Hydrate formation is a serious problem, especially early in the test when the well has not been warmed by extended flow. To avoid plugging the line with hydrate, glycol or methanol may be injected into the fluid before it reaches the choke. Additionally, a heat exchanger warms fluid downstream of the choke. Peculiar to HPHT tests, an extra 15,000-psi choke is sometimes incorporated in the heat exchanger.

Therefore, early in the test when hydrates could form in the line, pressure is initially reduced by the heater choke. Heating the reservoir fluid also aids separation. For HPHT wells, conventional separation and sampling techniques are sufficient. Fluid volumes are then metered and disposed of, usually by flaring.

5.3.7 Smartwell

To achieve optimum production, complex reservoir management is required. Smartwell 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 275º F.
- Power – Current battery limit is 350º F.
- Dynamic Seals – Current limit for dynamic seal technology is 400ºF.
- Maintenance – Current systems require ability to replace or calibrate components

5.3.8 Packers

Packers factor heavily in testing strategies for HPHT drilling and completion programs. High temperatures can cause:

- Significant pipe movement or high compression loads at the packer, particularly when high temperatures are combined with high operating pressures
- Increased mechanical and fluid friction as the well depth increases and/or deviates from vertical
- Thermal cycling and resulting tubing stresses requiring careful consideration of the use of tubing to packer connections (floating seals vs. static or no seals at all)
- Shorter elastomer performance life and de-rated yield strength of metals used in packers and seals

High pressure regimes require:

- Much thicker cross-sections in all tubulars and downhole equipment
- High-yield strength materials to handle excessive burst and collapse pressures
- Corrosion-resistant alloys (CRAs) when needed to protect from wellbore fluids that can corrode high-yield steel

The driving issues in packer systems involve rig cost/time and reduction of casing stresses caused by packer slips. Design issues include:

- Metallurgy selection
- Sealing technologies (static/dynamic)
- Packer to tubing interfaces
- Combined loading and pressure differential
- Interventionless packer setting devices

Safeguards and processes from earlier stages of the projects are wasted if the HPHT equipment is not deployed flawlessly at the well site. A multi-member team consisting of the operating and completion company project management, service center personnel, and field service technicians should be involved throughout the drilling and completion phases.

Table 13 defines the current state of the art for packer technology and current applications.

Table 13. HPHT Packers

HPHT PACKERS USED IN OFFSHORE DRILLING	Temp	Max. Differential Pressure (psi)	Setting Method	Casing Sizes	ISO Rating & Grade	Hostile Environ
BAKER OIL TOOLS						
Permanent Retainer Production Packers						
Model SAB	450°F	15,000	Hydraulic	9	ISO 14310 VO	Yes
Model SB-3H	400°F	10,000	Hydrostatic	3	ISO 14310 VO	Yes
Model DAB	400°F	10,000	Wireline/Hydraulic	14	*	Yes
Model FAB	400°F	10,000	Wireline/Hydraulic	10	*	Yes
Model FB-3	450°F	15,000	Wireline/Hydraulic	4	ISO 14310	Yes
Model HEA	400°F	15,000	Wireline/Hydraulic	5		Yes
Retrievable Retainer Production Packers						
Model Hornet	350°F	10,000	Compression or Tension	7	ISO 14310 V3	Yes
Model Premier	350°F	10,000	Hydraulic	7	ISO 14310 VO	Yes
Model Premier with Striker Module	350°F	10,000	Hydrostatic	4	ISO 14310 VO	Yes
Model HP-1AH	450°F	12,000	Hydraulic	4	*	Yes
Model M Reliant Series	350°F	10,000	Compression	4	*	Yes
Model WL	350°F	10,000	Wireline	5	*	Yes
Model HPR Edge	250°F	10,000	Electronic/Hydrostatic	2	*	Yes
Model HP/HT Edge	250°F	10,000	Electronic/Hydrostatic	2	*	Yes
* ISO 14310 qualification can be achieved for most packers through testing. Packers not ISO 14310 rated have packer envelopes correlated to performance testing. Packing elements will be selected according to hostile environment conditions.						
HALLIBURTON						
Permanent						
Perma Series HPHT Hydrostatic Set Packer	450°F	20,000	Hydrostatic	2	ISO 14310 VO	Yes
Perma Series HPHT Hydraulic/Hydrostatic Set Packer	450°F	15,000	Hydraulic/Hydrostatic	6	ISO 14310 VO	Yes
Sealbore Permanent						
Perma Series Permanent Seal Bore Packer	450°F	15,000		7		Yes
Retrievable						
"Triple H" Hydrostatic Retrievable Packer	400°F	15,000	Hydrostatic	1	ISO 14310 VO	Yes
HPH Hydraulic Set Retrievable Packer	400°F	10,000 - 15,000	Hydraulic	4	ISO 14310 V3/VO	Yes
Sealbore Retrievable						
Versatrieve Retrievable Sand Control Packer	400°F	10,000 - 16,500		4	ISO 14310 V3	Yes
Mechanical Set Packers						
PLT Mechanical Set Packer	325°F	10,000	Mechanical	3	ISO 14310 V3	No
SCHLUMBERGER						
Tubing Mounted						
XHP Premium Production Packer	325°F	10,000	Hydraulic	3	ISO 14310 VO	No
Omegamatic Packer	325°F	8,000	Compression	10		No
Omegamatic Long-Stroke Packer	325°F	6,000	Compression	4		No
Sealbore Permanent						
HSP-1 Hydraulic-Set Permanent Packer*	325°F	7,500	Hydraulic	8	ISO 14310 V6	Yes
Sealbore Retrievable						
Quantum X Packer	325°F	10,000	Hydraulic	4	Exceeds ISO 14310 V3	Yes
*Dual piston packer originally used in the North Sea. No longer being developed unless by special request.						

Notes:
1) Max. Differential Pressures are averages. Some specific sizes may have higher or lower rating.
2) In the Casing Size column, the total number of casing sizes offered for that particular packer are listed.
3) Hostile environments are defined as having CO2 or H2S conditions present.

5.3.9 Elastomers

Demands imposed on elastomers by deepwater, HPHT conditions remain severe despite advances in technology. Higher valve-opening pressures associated with deep-set applications have emerged, and to address those needs conventional solutions have focused on balancing the wellbore and its reaction to the hydraulic piston area using mechanisms that require seals and/or gas chambers. These solutions are heavily dependent on elastomeric seals and/or permanent long-term containment of a dome charge or pressure counterbalance to retain reliability. Unfortunately, dynamic elastomeric seals have posed a major limitation when design intent tries to focus on equipment that will provide life-of-the-well reliability.[5]

The capacity of BOP to resist pressure depends on the elastomeric seals inside the rams and their likelihood of not being extruded. As temperature increases, extrusion becomes more likely. Seals may

[5] Mike Vinzant, James Vick, and Anthony Parakka: "A Unique Design for Deep-Set Tubing-Retrievable Safety Valves Increases Their Integrity in Ultra Deepwater Applications," SPE 90721, March 2004.

have to withstand prolonged temperatures that top 400ºF, which is beyond the limits of ordinary components. Finite-element analysis has been used to identify which areas of the BOPs are most affected by heat and which seals need special elastomers rated to 350ºF.[6] Sometimes, special BOP temperature monitors are used to ensure these extended limits are not breached. However, high-temperature elastomers are harder than their low-temperature counterparts and may not seal at ambient temperature, making surface pressure tests difficult.

Once BOPs and choke are closed, pressure builds in the annulus and drill pipe. The maximum drill pipe pressure is used to calculate bottomhole pressure, which in turn determines the kill strategy.

Well-control equipment used during drilling is designed to handle reservoir fluids for relatively short periods. During a test, the surface equipment must cope with long flow periods. Where possible, elastomers are replaced by metal-to-metal seals, removing the temperature limitation of test equipment. Surface and subsea equipment are monitored using temperature and pressure sensors that report back to a real-time monitoring system, which initiates the emergency shutdown (ESD) system if limits are breached. In addition, the number of downhole test tools and the number of operations they perform are kept to a minimum.

5.3.10 Wireline Testing

Optimizing wireline formation evaluation begins with planning that weighs both the prioritized data requirements and time constraints posed by logging in HPHT environments. Since all practical methods of protecting sensors and electronics are time constrained, all options must be explored to acquire a maximum amount of data in a finite amount of time downhole.

Priorities are given to data that operators believe are most important for well evaluation. If those data are a deliverable, then other lower priority services may be addressed.

Tool systems that can deliver a wider range of data will be designed to optimize the amount of time spent downhole. Indirect measurement techniques can minimize the number of tools and time spent downhole.

For example, if porosity measurements are required, there may be indirect methods to determine porosity. Hence, a porosity measurement may be inferred indirectly from a combination of other tool measurements, charts, and samples.

The normal break-over point for HPHT specs is temperature over 350°F. This point precludes many electronic components. Motorized tools are especially susceptible to high temperatures as they need to dissipate internal heat to the wellbore. Many internal motors, therefore, operate at temperatures that are 50°F (28°C) over ambient. Other very basic principles also are jeopardized in high temperatures. Common thermal shielding traps may prohibit the sensor from making the intended measurement, mandating that some sensors be left unshielded.

The issue of finding and utilizing electrical insulating materials such as elastomers and epoxies that can withstand HPHT conditions also must be addressed. Suppliers have done a good job of upgrading materials used in logging systems, including seals, adhesives, rubber components, fiberglass components, etc.

Drilling for natural gas below 15,000 ft has presented the electronics industry with a challenging environment. Locating an instrument for pressure or flow measurement at the end of three miles of pipe poses problems for electronics, including withstanding temperatures ranging from 250°F (121°C) to 437°F (225°C) for prolonged periods of time.

[6] McWhorter DJ: “High Temperature Variable Bore Ram Blowout Preventer Sealing,” OTC 7336, May 3–6, 1993.

Table 14. Completion Technology Gap Analysis (part 1)

	Pres	Temp	Service	Issues	R&D Requirements
Completion Fluids	N/A	N/A	N/A	Because fluid volume changes with temperature, fluid expansion is an issue. Density is limited to 20#/gallon. Fluid loss and corrosion are problems.	Develop additives to reduce fluid loss and formation damage. Find materials with lower expansion characteristics and corrosion rates.
Flow Assurance/Prod. Chem ▪ Surface ▪ Bottomhole	 N/A N/A	 N/A 450°F	 N/A H2S	Injection pressure and depth are limiting factors . Low dose hydrate inhibitor tested to 275°F.	Improved injection systems. Testing equipment rated to 500°F – 30,000 psi.
Stimulation	15K	400°F	N/A	Wellhead treating pressures are limited by subsea tree ratings. Proppants could be an issue.	Design & build wellhead isolation tool. Examine proppant suitability at 30 kpsi – 500°F. Determine best completion methods.
Perforating ▪ Rated ▪ Case Basis	 N/A N/A	 400°F 450°F	 N/A N/A	Advertised perforation rating is 400°F; with HMX temperatures of 450°F, perforation can still be achieved. Issues with TCP include amount of time system is on, transmitting pressure for firing, and wireline takes too many trips.	Improve charge chemistry. Increase operational temperatures of electronic firing systems to 500°F. Discover better conveyance methods.

Table 14. Completion Technology Gap Analysis (part 2)

	Pres	Temp	Service	Issues	R&D Requirements
Completion Equipment Equipment (Seals) Slips Measurements	 25 kpsi 500,000# N/A	 400°F N/A 350°F	 H_2S H_2S H_2S	Injection equipment. Seal leakage. Slip damage to casing walls. Measurement technology. Lack of adequate testing facilities.	Improved injection systems. High temp sealing or "0" leak path. Better or new slip design. Improved electronics or fiber optic measurements. Testing facilities are needed to evaluate designs
SmartWell	15K	275°F	N/A	Sensors (Measurements) – See Completion Equipment. Dynamic Seal technology – limit 400°F. Downhole power – battery limit 350°F.	Valve technology rated to 30,000 psi/ 800°F. Electronics or fiber rated to 800°F. Downhole power sources.
Well Testing	10 kpsi +	350°F	N/A	Accurate data collection and testing required. HPHT laboratory testing at surface limited to 300°F and 20 kpsi. Test equipment limited by operating temperature/pressure confines. Hydrate formation can plug lines and pose serious problems early in testing.	Laboratory facilities/test equipment must be able to reconstruct downhole temperature and pressure conditions for accurate evaluations.

Table 14. Completion Technology Gap Analysis (part 3)

	Pres	Temp	Service	Issues	R&D Requirements
Packers Permanent Retrievable	10–15 kpsi	300°F 450°F	CO_2 & H_2S	Rig cost/time. Casing stresses caused by packer slips and thermal cycling. Downhole temperatures, pressures, and corrosive elements.	One trip/interventionless packer-setting devices need further development. Packer to tubing interfaces. Combined loading and pressure differential. Metallurgy selection and availability. Continuing instrumentation and material development to meet ever increasing downhole temperature and pressure conditions.
Elastomers		400°F max	N/A	Elastomeric seals are not reliable in retaining life-of-the-well integrity in managing pressures in BOPs.	Further development of polymers and metal-to-metal seals that can withstand extreme, corrosive, HPHT well conditions while retaining mechanical properties, chemical performance, and well fluid compatibility.
Wireline Testing	10 kpsi +	350°F	N/A	HPHT conditions limits instrumentation time for data retrieval while making downhole well evaluations.	Develop tool systems for reliable evaluations in HPHT conditions. Utilize indirect measurement techniques.

5.4 Assessment of Completion Technology

An individual assessment for each of the technologies is discussed below. Table 15 (on page 59) gives an overall risk comparison of selected well drivers on well completions.

5.4.1 Completion Fluids

Requirement: During the completion process, provide a means of well control compatible with both the formation and well equipment.

1) Identify physical design parameters in the specified environment
   - Mixing – Types of mixing equipment
   - Hole Stability – Formation type, pore pressure, frac gradient, lost circulation control
   - Fluid Stability – Pressure, temperature, H_2S, CO_2
   - HSE – Disposal, toxicity
   - Corrosivity – Pressure, temperature, metallurgy
   - Formation Compatibility – Formation type, fluid type

2) Identify impact of selected drivers on well design

   <u>High Impact Issues</u>
   - Hole Stability – In the HP/HT environment, fluids with higher density (as opposed to present day values) may be required.
   - Formation Type – Formation damage is generally high for brines.
   - Formation Compatibility – Existing completion fluids could be compatible with the formation; but until cores can be reliably tested, the answer is unknown.

   <u>Medium Impact Issues</u>
   - Lost Circulation Control – Since pore pressure and frac gradient are close in value, lost circulation control can be an issue.
   - Corrosivity – Similar issues are discussed in *Fluid Stability*.
   - Fluid Stability – Aside from providing well control, pressure is not a major issue but temperature is. At elevated temperatures, fluid stability is an issue relative to the formation and metallurgy. Pipe dope and drilling fluid can cause contamination. There is also the possibility of flocculation.

   <u>Low Impact Issues</u>
   - HSE – Handling, disposal, and toxicity are covered by current technology.
   - Mixing – Different types of mixing equipment are currently addressed.

3) Define limits of current technology vis-à-vis DeepStar requirements:
   - Mixing – Technology is not a limit.
   - Hole Stability – The current density limit is 20.0 ppg. Formation type, pore pressure, and frac gradient are issues handled on a case-by-case basis. Analytical tools are available to determine formation compatibility.
   - Fluid Stability – At elevated temperatures, fluid stability is an issue relative to the formation and metallurgy. Methods are available to determine fluid density changes with pressure and temperature. Additives can be used to control pipe dope contamination, drilling fluid contamination, and flocculation.
   - HSE – Handling, disposal, and toxicity are covered by current technology.

- Corrosivity – Issues are similar to those discussed under *Fluid Stability*. Corrosivity additives could be improved based on metallurgy.
- Formation Compatibility – Equipment to test formations with completion fluids is needed. With outside funding, StimLab is designing and building HPHT equipment for stimulation projects.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - Hole Stability – In this environment, controlling fluid density since pore pressure and frac gradient are nearly equal. Calculations may be the answer, but an additive to control density variation would be beneficial.
   - Corrosivity – Existing chemicals adequately control corrosivity. New metals may require additional additives to control corrosion.
   - Formation Compatibility – Equipment to address testing at 500°F is needed.

5.4.2 Stimulation

Requirement: Improve well performance by changing reservoir characteristics.

1) Identify physical design parameters in the specified environment
   - Storage – Bulk volume storage, conveyance, liquid storage
   - Mixing – Accuracy, quality control, proportioning
   - Proppants – Strength, effluent compatibility, temperature
   - Formation Type – Solubility, reactivity, temperature, pressure, composition
   - Transport Fluids – Gel strength, viscosity, pressure, temperature, pH
   - Treating Fluids – pH, inhibition, corrosivity, temperature stabilization
   - Wellhead Pressure Control – Wellhead treating pressure
   - HSE disposal, toxicity

2) Identify impact of selected drivers on well design

   <u>High Impact Issues</u>
   - Proppants (High) – Ceramic proppants are subject to damage by well effluents because of pin holes in their coatings.
   - Formation type (High) – Including the issues mentioned in proppants, there are issues related to formation compatibility with frac-fluids.
   - Transport fluids (High) – Because of the cooling action, when pumped from the surface, transport fluids are not currently an issue.
   - Wellhead pressure control (High) – Wellhead treating pressure could exceed subsea tree working pressure.

   <u>Low Impact Issues</u>
   - HSE (Low) – DOT, disposal and toxicity are similar to currently available products.
   - Treating fluids (Low) – Fluid density determines bottom hole treating pressure. This is critical in XHPHT acidizing. If acidizing is needed for XHPHT wells, inhibitors for 500F may be required but will depend on the format being treated.
   - Storage (Low) – Bulk volume storage, conveyance and liquid storage are adequate to handle current and future requirements.
   - Mixing (Low) – Accuracy, quality control and proportioning are available for current and future needs.

3) Define limits of current technology vis-à-vis DeepStar requirements:
    - Storage – Storage on stimulation vessels is adequate. Additional vessels can be called into service for large jobs.
    - Mixing – Computerized mixing and ramping systems provide adequate control and proportioning.
    - Proppants – Current technology is at it limits. Because of pin holes in their coatings, ceramic proppants are subject to damage by well effluents. Equipment for testing proppants with core samples is required for XHPHT environments. There is also a possibility of proppants imbedding in the formation and reducing frac conductivity.
    - Formation Type – See *Proppants*. There are issues related to formation compatibility with frac-fluids; testing equipment will have to be designed for 500°F.
    - Transport Fluids– Wellhead treating pressure can be exceeded with conventional treating fluids (i.e., weighted brines reduce wellhead treating pressure). And because transport fluids have a cooling action when pumped from the surface, they are not an issue at this point. Current technology used in 500°F wells should be adequate.
    - Treating Fluids–If acidizing is needed for XHPHT wells, inhibitors for 500°F may be required. This treatment is formation-dependent; at this time, this is a non-issue.
    - Wellhead Pressure Control – Current wellhead technology is limited to15 kpsi. Equipment designs are being considered for 20 kpsi and should be available in 2–3 years.
    - HSE – Currently available methods are adequate.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Proppants – Current technology is at its limit. Improved coatings or a new material will be required to meet XHPHT conditions. Testing equipment needs to be designed to analyze proppants imbedding in the formation, frac conductivity reduction, or proppant crushing due to excessive reservoir stress caused by geo-pressure.
    - Formation Type – See *Proppants*.
    - Transport Fluids – Weighted brine gels are required to reduce wellhead treating pressures.
    - Wellhead Pressure Control - Wellhead isolation equipment will be necessary to address wellhead treating pressure.

5.4.3 Flow Assurance

Requirements: Through chemistry or insulation, reduce the effects of hydrates, asphaltenes, paraffins, scale, corrosion, H_2S, CO_2 and emulsions in wells and flow lines.

1) Identify physical design parameters in the specified environment.
    - Deployment – Types of metering systems.
    - Injection – Location and method of injection.
    - Areas of Control – Hydrates, scale, corrosion, CO_2, emulsions.
    - Compatibility with Well Effluents – Test equipment, monitoring.
    - Compatibility with Equipment – Seafloor conditions, flowline conditions.
    - HSE – Handling, disposal, toxicity.
    - Insulation – Out of scope.

2) Identify impact of drivers on well design.

    <u>High Impact Issues</u>
    - Deployment – Determines injection pressure and rate to prevent flow inhibition.

- Injection – Particularly in situations where asphaltenes and paraffins are present. Chemical injection will have to occur in excess of 10,000 ft. below the mud line; very high injection pressures will be required.
- Areas of Control – While products are available for hydrates, scale, corrosion, H_2S, CO_2 and emulsion control, enhanced products may be required to handle effluents produced in more hostile environments, particularly hydrates and H_2S.
- Compatibility with Well Effluents – Improved test equipment is required to determine suitable products for this environment.

Medium Impact Issues

- Compatibility with Equipment – Equipment to introduce production chemicals is needed at seafloor and flowline conditions. Existing equipment could prove to be adequate, but investigation may be worthwhile.

Low Impact Issues

- HSE – Current technology is adequate for handling, disposal, and toxicity requirements.

3) Define limits of current technology vis-à-vis DeepStar requirements.
    - Deployment – Most metering is done with a stop watch and control valve.
    - Injection – Injection pressures could exceed umbilical pressure ratings, and injection points will surpass the design limits of currently available equipment.
    - Areas of Control – Current chemicals will work to a bottomhole temperature of 450°F. Low dosage hydrate inhibitor currently works to 275°F wellhead temperature. Insulation is also being used to minimize seafloor cooling effects.
    - Compatibility with Well Effluents – These HPHT deepwater well conditions will challenge the capabilities of existing equipment.
    - Compatibility with Equipment – Pressure ratings of wellhead equipment and the number of injection line feed-throughs may have to be increased on wellheads. Current rating is 15 kpsi.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Deployment – Install automated injection systems.
    - Injection – Until well fluids are actually produced, this is an open area. Higher pressure ratings for umbilical lines and injection subs could be required.
    - Areas of Control – Chemicals that will work for conditions of 500°F BHT.
    - Compatibility with Equipment – Equipment requirements are driven by the well injection points that will be determined according to the well fluids produced.

5.4.4 Perforating

Requirement: Perforate the casing wall, cement sheath, and formation to create a flow path to allow well effluents to enter the wellbore or allow injection into the formation.

1) Identify physical design parameters in the specified environment.
    - Firing Devices – Operating methods include pressure, mechanical, and electrical.
    - Initiators – Type and temperature limits.
    - Primer Cord – Type and temperature rating.
    - Shape Charges – Size, type, and temperature rating.
    - Gun Case – Size, shot pattern, and collapse rating.

2) Identify impact of those drivers on well design.

High Impact Issues

- Firing Heads – The ability to initiate ignition is critical to successful detonation.
- Initiator – This second stage in the detonation process is also a critical point.
- Primer Cord – Responsible for detonating shape charges and propagating detonation.
- Shape Charges – Performance and reliability (size and penetration) dependent on duration of high temperatures, the amount of powder, and chemistry.
- Gun Case – Collapse is an issue at HPHT conditions.

3) Define limits of current technology vis-à-vis DeepStar requirements:

- Firing Heads – Current equipment works to 450°F with extensive pre-job planning. Improved charge-chemistry is required.
- Initiators – Current equipment works to 450°F with extensive pre-job planning. Improved charge-chemistry is required.
- Primer Cord – Current equipment works to 450°F with extensive pre-job planning. Improved charge-chemistry is required.
- Shape Charges – Current equipment works to 450°F with extensive pre-job planning. Improved charge-chemistry is required.
- Gun Case – Sleeves are installed over gun cases to prevent collapse. This additional wall thickness is effective in improving the gun collapse rating to meet DeepStar objectives.

4) Identify necessary gap closures prior to drilling DeepStar wells.

- Develop explosive chemistry rated to 500°F or conceive another means to create perforations. Currently available systems are limited to 400°F.

5.4.5 Completion Equipment

Requirement: Manage production by isolating well segments, initiating production, providing safety/emergency systems, and controlling inflow/injection performance.

1) Identify physical design parameters in the specified environment.

- Equipment – Component sealing, wellbore sealing, pressure, service, temperature, and stress.
- Maintenance – Plugs, safety valves, sliding sleeves, and injection subs.
- Operation – Slick line, coil tubing, HWO, and remote control.
- Measurements – Pressure, temperature, and flow.
- Casing damage – Slip design, setting force, and setting.

2) Identify impact of those drivers on well design.

High Impact Issues

- Equipment – Correct operation and well control depend on both internal and external seals. Ratings for pressure, service, temperature, and stress determine suitability for use.
- Maintenance – Ability to maintain both the equipment and the well are important factors effecting production.
- Operation – To adequately control the well sleeves, valves and plugs are necessary to change production or injection parameters. To achieve this slick line, coil tubing, HWO, remote control will be required.
- Casing Damage – Slip creates stress concentrations in casing walls. This stress is excessive in HPHT wells and can lead to premature casing failure.

Medium Impact Issues

- Measurements – Measurements provide input in the decision making process. Readily available information will improve reservoir management.

3) Define limits of current technology vis-à-vis DeepStar requirements.

- Equipment – Seal technology is a major issue. Metal serves well in static situations although it leaks in dynamic situations (excepting balls and valves). Elastomers, used in dynamic sealing designs, fail after several cycles above 400°F. The ability to inject chemicals through an injection sub into the wellstream is not only critical, but also limited to the umbilical rating and the location of the sub in the production string.
- Maintenance – Because of the water depth, intervention is extremely difficult. Riserless and sea floor intervention offers promise, but it is outside the scope of this project.
- Operation – See *Maintenance*. Remote operation is possible but faces the same issues mentioned in *Equipment*. Electro-magnetic technology has potential and is now available for SSCV. Slick line could break under its own weight in this situation.
- Measurements – Measurements are limited to 350°F, and cabling can be problematic. Fiber optics offer possibilities but are only available for temperature (work in progress for pressure).
- Casing Damage – Because of large temperature changes in the wellbore, weights of 500,000 pounds can rest on the packer and be transferred to the casing walls. This is a major issue.

4) Identify necessary gap closures prior to drilling DeepStar wells.

- Equipment – Improved methods of sealing are required to operate in this environment both from a dynamic and static standpoint. Injection methods require improvement to inject into the well stream at the 30 kpsi, 500°F case.
- Operation – Further work, like the electro-magnetic operated SSCV, will eliminate possibilities of leaks from the tubing to the annulus thereby ensuring well integrity. Improvements in electronics and actuators offer major advantages for controlling downhole equipment. Providing downhole power to operate equipment would simplify operations.
- Measurements – Accurate pressure and flow measurements rated to 500°F is advantageous in optimizing reservoir management.
- Casing Damage – Methods for setting packers without slips would ensure well integrity and reduce casing damage.

5.4.6 Well Testing

Requirement: Gather accurate downhole data that can be used for equipment selection, drilling parameters, and operational capabilities of the HPHT well.

1) Identify physical design parameters in the specified environment.

- Managing pipe movement or high compression loads at the packer particularly when the high temperatures are combined with high operating pressures.
- Controlling increased mechanical and fluid friction as well depth increases and/or deviates from vertical.
- Engineering tubing stresses to enable proper use of packers.
- Maintaining reliability of integrated circuits under high pressure, high temperature, corrosive environments.

2) Identify impact of those drivers on well design.

High Impact Issues

- Surface equipment must cope with long flow periods.
- Test equipment limited by operating temperature and pressure confines.

- 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 upon settling.
- Hydrate formation can plug lines.

Medium Impact Issues

- Continued need for training and qualified personnel.
- Accurate data collection is essential to successful estimation of testing parameters.

3) Define limits of current technology vis-à-vis DeepStar requirements.
   - Equipment – Current integrated circuit technology is limited to 10,000 psi and 350°F.
   - Maintenance – Intervention requires re-entry into the wellbore through risers or using riserless methods.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - Surface equipment design must be modified to take into flow periods, volumes, and space considerations on deepwater platforms.
   - Fluid engineering and design must advance to minimize plugging pressure ports, improve tool reliability, and reduce negative impact on test strings.
   - Integrated circuit technology must advance to reliably address pressure and testing considerations for deepwater, HPHT well testing conditions.
   - Monitoring technology must advance to allow for the continuous monitoring of all produced fluids to enable remote, real-time intervention by operators.

5.4.7 Smartwell

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

1) Identify physical design parameters in the specified environment.
   - Equipment – Sealing, reliability, electronics, control devices, actuators, power, flow, communications, pressure, and temperature.
   - Maintenance – Repair, calibration, and replacement.
   - Reservoir management – Out of scope.

2) Identify impact of those drivers on well design.

   High Impact Issues

   - Equipment – Sealing, reliability, and electronic issues have been previously discussed in *Completion Equipment*. Control devices and actuators will be needed to facilitate operations. Reliable sensors are paramount to successful operations and reservoir management.
   - Maintenance – The ability to repair, calibrate, and replace equipment is necessary.

3) Define limits of current technology vis-à-vis DeepStar requirements.
   - Equipment – Current technology is limited to 15,000 psi and 275°F. Batteries are available to 350°F; mercury batteries work to 400°F but are environmentally problematic, and cables are complex.
   - Maintenance – Intervention requires re-entry into the wellbore through risers or using riserless methods.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - Equipment – Develop equipment, actuators and sensors that will work at 20,000 psi and 500°F or above. Low cost downhole power is needed to operate equipment and sensors.
   - Maintenance – Develop intervention processes that will result in lower cost methods of repair, calibration, and replacement.

5.4.8 Packers

Requirement: Seal the wellbore, isolate the productive zone, and redirect the flow downhole. A packing element seals off the inside of the casing and contains pressure when the packer is set.

1) Identify physical design parameters in the specified environment.
   - Equipment – Operational parameters and performance rating requirements
   - Sealing technologies – Static and dynamic
   - Operation – One trip and/or interventionless
   - Combined loading, pressure differential, and thermal cycling – Selection of tubing to packer connections (floating seals vs. static or no seals at all).

2) Identify impact of those drivers on well design.

   High Impact Issues
   - Pipe Movement and High Compression Loads at the Packer – Results from the combination of high temperatures with high pressures.
   - Mechanical and Fluid Friction – Increases with well depth or with vertical deviations.
   - Thermal Cycling and Tubing Stresses – Thicker cross sections in all tubulars and high yield strength materials to handle excessive burst and collapse pressures.
   - Materials Used in Packers and Seals – Shorter elastomer performance life and de-rated yield strength of metals.

   Medium Impact Issues
   - Installation Mishaps – Detailed knowledge required of equipment design, testing, and assemblage.
   - Contingency Planning – Crucial for situations requiring lead times for alternate equipment.

3) Define limits of current technology vis-à-vis DeepStar requirements:
   - Packer and Seal Materials – Current metallurgy and materials are reliable for applications requiring 300 to 350°F at 10,000 psi.
   - Packer Setting Devices – Current equipment works to 450°F with extensive pre-job planning. Need for interventionless packer setting devices and the reduction in the number of downhole trips.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - For temperatures and pressures above the 400°F, 10,000 psi limits, more exotic alloys and components that require ratings and standardized testing are required. However, their performance reliability is still undetermined ; further testing is necessary.
   - Compatibility of tubing, packer and well fluids to downhole conditions should be required.
   - Accurately define operational parameters and performance rating requirements for any new equipment

5.4.9 Elastomers

Requirement: Used as a sealant in blow-out preventers thereby increasing the resistance of the BOP to increased pressure demands.

1) Identify physical design parameters in the specified environment.
   - Sealing Technology (static and dynamic).
   - Seal Durability.

2) Identify impact of those drivers on well design.

   High Impact Issues
   - Reliability – As temperature increases, extrusion of the elastomeric sealants likely.
   - Temperature – High temperatures shorten elastomer performance life.
   - Testing – High temperature elastomers are harder than their low temperature counterparts and may not seal at ambient temperatures, thereby making surface pressure tests difficult.

3) Define limits of current technology vis-à-vis DeepStar requirements.
   - Reliability – No current tests can adequately predict reliability.
   - Temperature – Currently can withstand temperatures to 350°F.
   - Testing – High temperature elastomers are harder than their low temperature counterparts and may not seal at ambient temperatures, thereby making surface pressure tests difficult.

4) Identify necessary gap closures prior to drilling DeepStar wells.
   - Further development of polymers and seals that can withstand extreme, corrosive, HPHT well conditions while retaining mechanical properties, chemical performance, and well fluid compatibility.
   - Extensive seal research required. In some cases, metal-to-metal seals may replace elastomers.
   - Better surface testing procedures that can help predict downhole reliability.

5.4.10 Wireline Testing

Requirement: Acquire the maximum amount of downhole data in the minimum amount of time.

1) Identify physical design parameters in the specified environment.
   - Reliability – Measurement components become unreliable according to the amount of time spent downhole.
   - Temperature – Cannot withstand temperatures above 250°F.
   - Equipment – Motorized machinery adds to the downhole temperature. Electronic components cannot withstand HPHT conditions. Thermal shielding may influence readings.

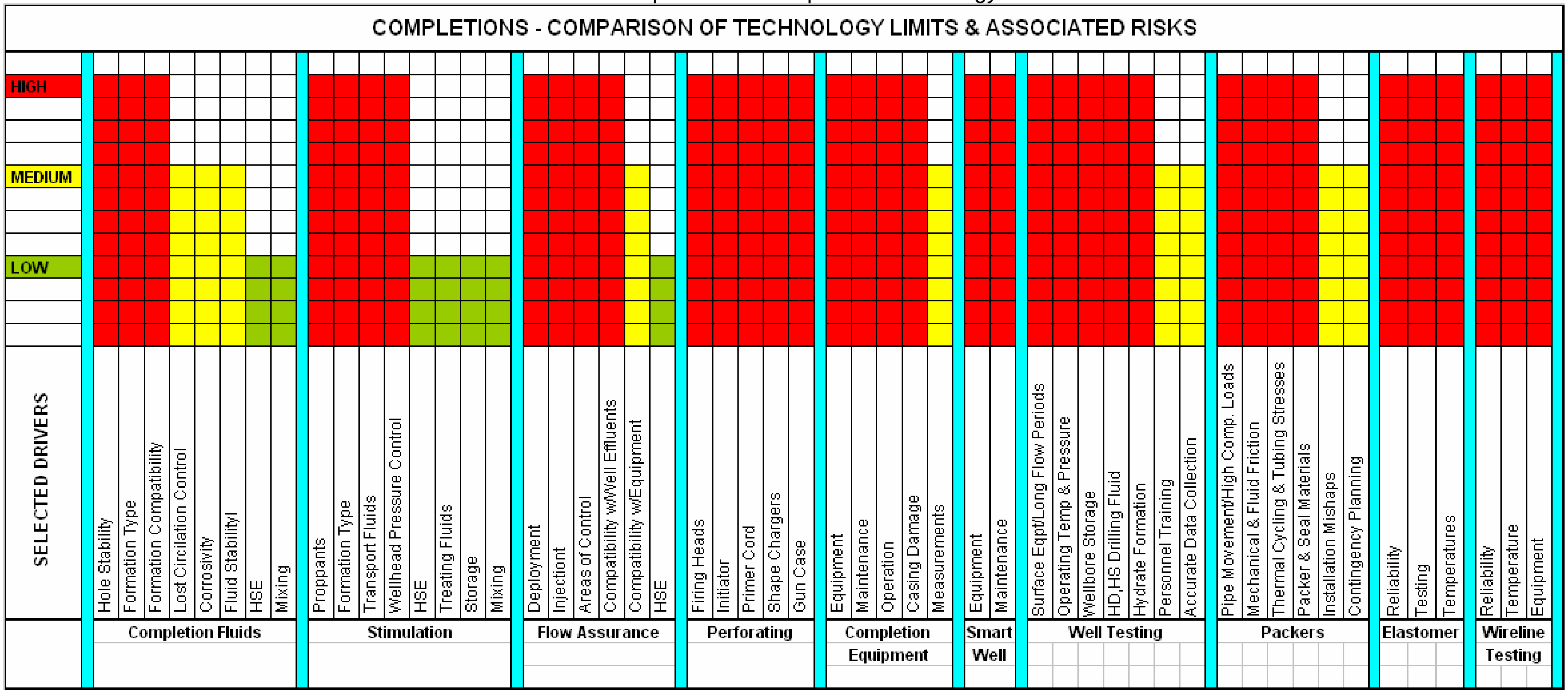
2) Identify impact of those drivers on well design.

   High Impact Issues
   - Reliability – Measurement components become unreliable according to the length of time spent downhole.
   - Temperature – Cannot withstand temperatures above 250°F.
   - Equipment – Motorized machinery adds to the downhole temperature. Electronic components cannot withstand HPHT conditions. Thermal shielding may influence readings.

3) Define limits of current technology vis-à-vis DeepStar requirements.
    - Equipment and Components – Research on nonconductive materials needs to be incorporated into test equipment .
    - Temperature – Currently can withstand temperatures to 250°F.
    - Time Constraints – Amount of time equipment can remain downhole is limited.

4) Identify necessary gap closures prior to drilling DeepStar wells.
    - Tool systems that can deliver a wider range of data need to be developed.
    - Indirect measurement techniques need to be refined.
    - Data requirements need to be prioritized.
    - Equipment needs to be developed to withstand temperatures ranging from 250–435°F for long periods of time, including the use of non-conductive materials.

Table 15. Comparison of Completion Technology Limits



6. Recommended Projects

6.1 Drilling Projects

Industry groups are currently funding projects that address many of the issues related to extreme HPHT. More than half of these projects are devoted to technology that will enable LWD/MWD and logging in these environments. Most service companies prefer to keep their R&D spending confidential; as a result, those expenditures are not included in any figures used for this report. Two major technological areas identified as investment opportunities include a systems approach to drilling and test facilities which simulate extreme HPHT conditions. Estimates follow.

	Cost	Time
• Work with DOE, DeepTrek and DEA to incorporate DeepStar Goals into existing projects related to electronics and sensors	**$0**	**3 yr** *(Already funded)*
1. High temp electronics – 30,000 psi, 500°F		
2. Continue work on fiber optic sensors		
3. Advance battery technology		
4. Lower manufacturing costs for components		
5. Improve reliability a) Temperature b) Vibration		
• Inclinometer (MWD/LWD) Project currently planned for 2007 budget year. Could be accelerated by one year with identified funds.	**$500,000**	**1 yr**
• Take a systems approach		
1. Bits, mud, motors, drill string dynamics and rock dynamics to improve ROP	**$1,000,000**	**2 yr**
2. Mud, drill string dynamics, cooling to improve MWD/LWD reliability		
3. Identify best practices (Knowledge Management)		
4. Investigate methods to better manage equivalent circulating density (ECD)		
• Use Best-in-Class services		
• Enhanced operator training (rig operators)		
• Improve MWD motor and turbine designs 1. Torque 2. Faster RPM	**$1,000,000**	**2 yr**
• Study rock mechanics to improve ROP	**$300,000**	**1 yr**
• Mud system improvement to reduce friction pressure, improve thermal properties, control density, and improve ROP.	**$750,000**	**2 yr**
• Test fixtures and equipment (Multi-purpose drilling and completions)	**$2,500,000**	**3 yr**
• Investigate application of nanotechnology	**$200,000**	**6 mos.**
• Solid State Battery Cost is dependent on the formation of a consortium or JIP. Includes building construction cost and equipment purchase.	$**2,000,000**	**2–3 yr**
• Develop HPHT Turbine Generator *(Project funded by DOE to Dexter Magnetic Technologies)*	**$1,000,000**	**3 yr**
• Develop wellheads for 25 kpsi 450°F H_2S service *(Part of BOP/Subsea Tree design not in scope)*	**$2,000,000**	**3 yr**

• Review/Recommend revision of API, NACE and ASME specifications related to extreme HPHT (XHPHT) environments. Of particular interest are:	**$250,000**	**1 yr**

1. API
   a) 17D – Specifications for subsea wellheads
   b) 17TR3 – Evaluation and risk for penetrating subsea wellheads
   c) 13 Series – Drilling fluids specifications
2. NACE
   a) MR 0175 – Corrosion Control – Specifications to 400°F

6.2 Cementing Projects

Following are recommendations for improved cementing technology as derived from gap identification and survey results of this study.

	Cost	Time
• Investigate long-term effects of H2S and CO2 at BHST/BHP	**$1,000,000**	**18 mos.**
• Research and test alternative products and technologies as replacements for conventional Portland cement.	**$1,000,000**	**18 mos.**
• Research annular pressure in-between casings to ensure understanding and expertise in handling these issues.	**$1,000,000**	**18 mos.**
• Seek alternative sealants for tieback jobs to better define optimization techniques.	**$600,000**	**12 mos.**

6.3 Completion Projects

Following are recommendations for improved completions methodology as derived from gap identification and survey results of this study.

	Cost
• Completion fluids with lower coefficients of thermal expansion.	**$750,000**
1. Improved corrosivity resistance, fluid loss, and formation compatibility.	
• Completion Equipment	**$2,500,000**
1. Improved dynamic sealing capability.	
2. Designs for chemical injection equipment.	
3. Test equipment to develop design criteria.	
4. Improve static sealing.	
5. For drilling, apply electronic and sensor technology to completion equipment and Smartwell.	
6. Improved intervention technology.	
• Perforating	**$900,000**
1. Powder chemistry for 500°F service	
2. Gun cases rated to 30,000 psi	
3. Seals for 500°F	
• Stimulation	**$2,000,000**
1. High strength proppants	
2. Develop gels for heavyweight brines	
3. Design and build wellhead isolation equipment for 30K service	
4. Build test equipment for formation, proppant, and evaluation purposes	

- Flow Assurance **$750,000**
    1. Completion equipment designed for injection
    2. Hydrate and scale inhibition
- Smartwell *Already Funded*
    1. Develop batteries that will function at 500°F and 30 kpsi.
    2. Develop electronics that will function at 500°F and 30 kpsi.
- Packers **$1,000,000**
    1. Develop elastomer seals for 500°F and 30 kpsi conditions
    2. Revise metallurgy to withstand XHPHT conditions
    3. Develop metal-to-metal seals applicable to XHPHT conditions
- Elastomers *Ongoing*
    1. Formulate elastomers to withstand XHPHT pressures and temps.
- Wireline Testing **$750,000**
    1. Develop HPHT electrical insulator materials.
    2. Develop inferential test methods.
    3. Develop continuous duty HPHT electronics.
- Well Testing **$1,500,000**
    1. Packer and downhole equipment development.
    2. Originate and update laboratory test equipment for XHPHT conditions

7. Conclusions

7.1 HPHT Drilling Gaps

Based on analysis of historic HPHT well data and a survey of industry's capabilities, the major obstacles encountered when drilling XHPHT wells are formation and well evaluation tools. In most cases, wells can be drilled to the sensitivity objective, although obtaining logs and running LWD/MWD at these conditions is difficult.

Ongoing research is focused on addressing many of these challenges. This assessment has identified several areas that require attention. Elastomers, battery technology, and electronics/sensors are core technologies which require additional focus. Several emerging products offer potential solutions. If those products appear promising, they must be integrated into workable downhole tools.

Well drilling will also benefit from projects that optimize ROP 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 unique safety concerns for HPHT operations that must be addressed for future technology development and applied engineering activities.

The way forward is clear if reliability of smart tools is to be increased. Operating companies, as risk-takers and technology integrators, need to devote resources to the problem. Resources needed include money, expertise, and time. Residence of the resources may be at the operating companies or their proxies in the service sector. The key is to optimize the use of resources. The following recommendations are offered:

1. Hire/appoint an engineer or committee to champion this effort
2. Expand the group to include shelf drillers
3. Construct a detailed data base of all related past and current HPHT failures
4. Monitor all service company progress in regard to improved tool performance
5. Work with operations personnel to optimize procedures for use of smart tools
6. Integrate research efforts and focus on cooperation and technology application
7. Drill wells with the intention of sharing HPHT equipment data

Precise funding mechanisms for each aspect of technology research and development need to be defined. Participants in any or all projects will come from the group of operators, possibly drilling contractors, service companies, and regulatory agencies.

The engineer/champion could be a DeepStar representative, an individual seconded from a DeepStar member company, or a contractor. The engineer's sole job function would be to work on issues associated with smart tools; electronics, elastomers, environmental loading, application, reliability, operating techniques, and economics. To perform the job properly, the engineer would require access to data. That means daily drilling reports, equipment failure reports, and all other pertinent data needed to evaluate smart tool performance and evolution. The engineer could follow the procedure done in this study—sanitize the data so the wells would not be specifically recognizable, while preserving the knowledge of smart tool capabilities and limitations.

Operating companies need to recognize the fact that drilling operations are never secret. Putting a "tight hole" label on a well is tantamount to issuing a challenge to unravel the secrets. Within two years of drilling a well, anyone can purchase all the logs run in a GOM well in digital format, perform any analysis on the data and even compare the analyses to an interpretation of the huge mass of non-proprietary seismic data available for purchase at very reasonable rates. Scout information fleshes in the picture.

With regard to drilling issues, there is not a well drilled in the GOM where interested parties cannot determine exactly what particular service companies did. Rig crews are often a source of amazing details through informal discussions. **Given that logs costing millions can be obtained for fractions of pennies on the dollar a short time later, it makes absolute sense for oil companies to reveal their drilling "secrets" under strict confidentiality agreements within a framework of improving a critical set of technologies that directly impact drilling economics.** As soon as a well is drilled, one must consider what value those reports now have. These are seldom analyzed in great detail (the next project takes precedence) and are expensive to store in either paper or electronic formats. Discovery or dry hole, the well cost is sunk as soon as operations are completed. The only future value the information itself holds is realized if the lessons can be actively extracted and applied to future wells.

7.2 HPHT Cementing Gaps

There are many obstacles encountered when cementing HPHT wells. In most cases these wells can be cemented, although achieving quality cement jobs is sometimes quite complex. Ongoing research is focused on addressing many of these challenges. This assessment has identified several areas that require attention. Alternative sealing agents, modified testing procedures, and HPHT cement job design are a few of the core technologies which require additional research and focus.

In a time where exploration water depths and well depths are continuously getting deeper, we need to continuously pursue new procedures and technologies that will enable us to effectively isolate zones in oil and gas wells. Current products and materials work (to a greater or lesser extent) if an earnest amount of effort is expended. However, there is an irrefutable need for continuous research and development in oilfield cementing. Without these solutions, the industry cannot continue to effectively and efficiently pursue oil and gas in the most challenging environments.

7.3 HPHT Completion Gaps

In most cases, the industry has adopted a "wait and see" attitude concerning product development pending the issuance of exploration and development plans by operators. Currently, operators fund specific equipment and services necessitated by field demand rather than financially supporting product development prior to the actual need.

Flow assurance is the most critical issue in completion technology since production is paramount to the success of these developments. Many flow assurance issues are addressed in CTR 7201, 7202, 7204, and 7205. Completion fluids, completion equipment, and perforating are areas that require additional focus to meet DeepStar requirements.

Current laboratory test facilities are in general suitable for testing today's HPHT systems and their components. However, the industry will have to undertake 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.

First and foremost, metallurgy must be available. Sourcing metals such as nickel, alloys, Hastelloy (C-276), or possibly titanium, will be a challenge. Polymers and seals must be developed to withstand increased HPHT conditions while retaining mechanical properties, chemical performance, and well fluid compatibility. Standards, performance ratings, and quality assurance requirements need to be adopted and met for any new equipment or product.

The effect of high temperatures on equipment continues to be a primary obstacle in successful HPHT well completion. In addition, the continuing demand for real-time data gathering and formation evaluation remains unmet even though the risk associated with downhole extreme conditions would be minimized.

Appendix A – Nomenclature

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
bbl/MMscf	Barrels/million standard cubic feet
bcfg	Billion cubic feet gas
BHA	Bottomhole assembly
BHP	Bottomhole pressure
BHT	Bottomhole temperature
BML	Below mudline
BOP	Blow out preventer
DEA	Drilling Engineering Association
DOE	Department of Energy
ECD	Equivalent circulating density
Frac	Fracture
GOM	Gulf of Mexico
HIPPS	High integrity pressure protection systems
HPHT	High pressure, high temperature
HSE	Health, safety, and environment
IEEE	International Electrical & Electronics Engineers
JIP	Joint industry projects
Kpsi	1,000 pounds per square inch (pressure)
LWD	Logging while drilling
MMS	Minerals Management Service
MWD	Measurement while drilling
NACE	National Association of Corrosion Engineers
NPT	Non-productive time
ID	Internal diameter
OD	Outside diameter
OBM	Oil based mud
PDC	Polycrystalline diamond cutters
Psi	Pounds per square inch
QAQC	Quality assurance, quality control
R&D	Research and Development
RPM	Revolutions per minute
ROP	Rate of penetration
SIWP	Shut-in wellhead pressure
TD	Total depth
TSP	Thermally stable polycrystalline
WBM	Water based mud
WOB	Weight on bit
XHPHT	Extreme high-pressure, high-temperature

Appendix B – Summary of Meeting Notes from DeepStar Public Workshop on HPHT Technology Gaps (3/30/06)

Notes from DeepStar Workshop on HPHT Gaps

March 30, 2006

Top HPHT Priorities for Drilling

The attendees and project team worked together to develop a list of priorities:

1. Accurate measurements of what is failing in HPHT wells. We must document failure mechanisms for LWD/MWD, RSS, and motors. This is necessary to accurately define the HPHT "prize," to focus and direct research efforts, and to provide a baseline for performance improvements associated with application of HPHT research products.
2. Shelf wells must be included if there is an established process to measure, manage and expand information. These wells currently encounter the most elevated temperatures and pressures in the GOM. Several member companies have been partners or operators in deep shelf wells recently.
3. Recording well data and extracting useful information from data. The most effective research will be done if a large volume of applications are analyzed.
4. Effective means to control downhole pressures—BOP's, seals, materials, APB. This is critical with BOPE, casing metallurgy, casing connections, and well heads.
5. The effects of vibration on "smart" components need to be understood. Consideration should be made of means for obtaining and analyzing vibrational data in real time. Vibration intensifies the severe operating conditions associated with high temperatures.
6. A good first step toward extending the capabilities of currently-available "smart" components and motors will be development of a set of "best practices" based on a detailed analysis of well records. This should be possible to accomplish in a matter of months, provided sufficient well data are available to form a statistically-valid view of failures associated with current state of the art.

Top HPHT Priorities for Cementing/Completion

1. Higher performance materials for zone isolation. This includes better cements and effective seals (metal-to-metal and elastomers).
2. Equipment and techniques that minimize the need for workover intervention in wells. Completion add-ons that improve outcome.
3. Contingency options for later intervention.
4. Optimal stimulation methods.
5. Subsea completion equipment.
6. Data and improved models for designing completions for high pressure.

Other Needs/Comments from Attendees

1. Regarding elastomers and sealants, we should perform a search of other industries such as refining and food processing. They have addressed HP sealing previously.

2. Regarding allocation of R&D funding, service companies need to consider tasks and equipment whose application will cross over to other environments beyond HPHT. They see HPHT as a niche market and need cross-over benefits from new tools they develop.

3. Deeper wells require stimulation efforts beyond conventional wells due to formation compaction, and problems with fluid stability.

4. Technologies that improve safety, including Recommended Practices, are high priority.

5. H_2S is a critical concern. In deeper wells, you should assume the well is sour, until you know different. Materials are needed, including metals, cements, and seals. Shell published a paper at 2005 SPE showing a correlation between depth and CO_2/H_2S.

6. Annular pressure buildup (APB) is a critical issue. Need the ability to monitor integrity of tubulars. Vacuum-insulated tubing isn't a good answer. Some other alternatives should be considered.

7. We can't now design a tie-back liner at HP.

8. Completion needs are our current show-stoppers. We can drill these wells (maybe not cost-effectively), but cannot complete and produce many HPHT wells (including deep shelf wells). The industry lacks:
    a. BOPs
    b. Trees
    c. Hardware

9. Regarding elastomers, we need to think more generically (that is, resilient seals) to not limit our search for new materials.

10. Service limits for designing HPHT completions are not well understood. What are the flow testing needs? We don't know shut-in pressures for these wells. We need better analytical models to aid in sizing equipment for these wells.

11. The inability to properly evaluate xHPHT wells prevents proper completion and production designs. If better modeling for prediction capabilities were developed, we currently can't get adequate data and reservoir samples.

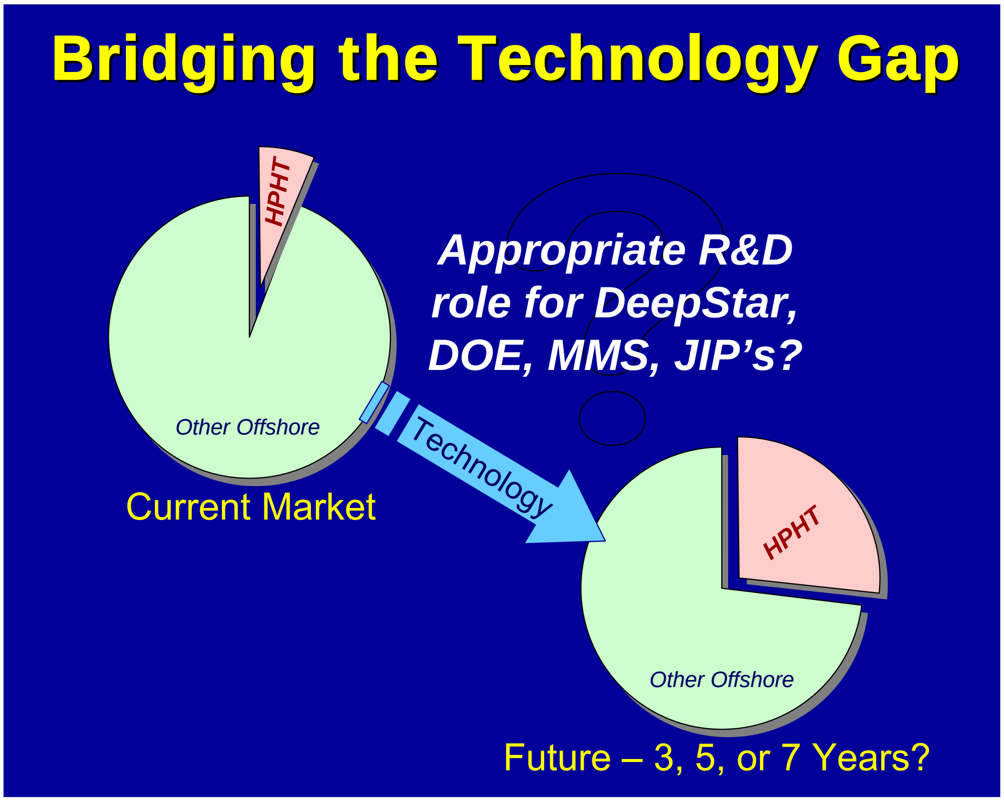
12. Proposed JIP on HPHT Data Mining.

In his summary of HPHT gaps, Tom Proehl highlighted the critical need for better measurements and documentation. He said,

- *"If you can measure it, you can manage it*
- *If you don't measure it, you need luck*
- *Good luck is what happens when preparedness meets opportunity"*

There was wide agreement among the attendees that industry's efforts to overcome HPHT challenges are being strongly hindered by lack of good measurements and documentation of experience, including successes, failures, and mistakes.

There was also a consensus among the attendees for the need for a JIP for mining industry data on HPHT operations. Most likely, this effort should take the form of a DeepStar CTR that would gather data from across the industry and "sanitize" it for complete anonymity. This would then be shared by all industry and updated regularly.



The project team requested comments and feedback on the materials presented and the report; and a discussion on the impact of the API RP 6 committed, as well as the proper and most productive role of Industry; DeepStar; JIP's; DOE; MMS, or other options to close the gaps.

Appendix C – Results from Survey of Attendees of DeepStar Public Workshop on HPHT Technology Gaps

DeepStar Workshop on HPHT Gaps

March 30, 2006

Comments Returned by Attendees

(compiled April 21, 2006)

After the HPHT Workshop was conducted, attendees were contacted by email and asked to complete a short survey. Their responses are summarized below.

1. Was the information beneficial? "Yes" (13 responses)

Additional comments:

- I was not aware of the big gap between the technology for drilling the wells and the technology for completing them.

- Yes, but until some action is taken to determine how the "gaps" will be overcome, it won't do much good in reality. Also, there seem to be many more questions that must be considered before the "gap" list is complete, but this is a good start.

- It seemed like the principal investigators may have been a little self serving. I may be cynical, but here are my observations. The investigator from CSI concluded that one of the biggest needs is better sealant/cement, which just happens to be what his company does. The investigator that gets consulting work analyzing the drilling data concluded that the most important thing is to collect more data (that he will get to analyze).

- I was very impressed with the progress made by the NETL people (especially the computer chips/processors developed with a grant to Oklahoma State). I think serious consideration should be given as to how these people from Oklahoma State and other researchers can be given opportunities for field experience on the rigs doing this type of work. In addition to verifying and validating theoretical and laboratory work, this would give researchers a chance at direct feedback from the drillers, who have a vast wealth of knowledge on "what happens," which would be valuable input to the research people working on "why things happen" (and vice versa).

- I noted with interest the comments about using some of the sections out of the Boiler & Pressure Vessel Code (ASME Section VIII, Div 3) as criteria for the HPHT. This should be taken beyond just the code and should also explore some of the Materials Engineering developed over the years by the downstream engineers that use this code. (We may need to familiarize ourselves with the Pressure Temperature Phase Envelopes used by the downstream engineers). The downstream engineers were required to find a replacement for asbestos (which was widely used in high temperature service). Changing to graphoil wasn't enough. The basic designs of some of the valves needed to be modified to allow for temperature limitations of new material(s). A similar approach may be needed for HPHT well heads, valves, etc.

- Portland cement was developed a long time ago, for low temperatures. If we're not already looking at high temperature refractory cements and materials, then we should look at these materials and others. In addition to (1) Cement; (2) Metals and (3) Elastomers; we should look at the way soils and rock behave at high temperatures and pressures. A HPHT sealing material would not be effective if the soil or rock that it seals against will in turn fail under high pressures and temperatures. Do we need to know more about this?

- Corrosion and Erosion of metallic materials at HPHT conditions did not seem to be covered. An anode material, working in 400°F seawater is hard to envision. If we can't cathodically protect these materials, then the phase envelopes for these materials become even more important.

- Overall this workshop was quite well done. I am glad you mentioned the need for a CTR for data mining. DeepStar badly needs this to provide data for a number of studies.

- DeepStar should document failures to include the shelf. Project is well justified.

2. Was the facility (other than the power outage) adequate? "Yes" (13 responses)

Additional comments:

- The facility was ideal. An offsite location ensures that everyone is focused on the workshop and not scurrying away checking e-mails!

- Great facility, noise outside started to roar at times, but we asked the hotel to manage. They could have quieted the hallway a bit better – Marriott issue as host.

3. Was the location convenient? "Yes" (13 responses)

Additional comments:

- For me it was an ideal location. I think Beltway 8 is a good artery from all areas of town.

4. Did the format allow sufficient discussion? "Yes" (10 responses)

Additional comments:

- I think there was good discussion and the time allowed was adequate. If I recall we actually finished a little early.

- Discussion could have been a bit more focused.

- Power outage was overcome with the discussion.

5. Were the materials adequate/effective? "Yes" (8 responses)

Additional comments:

- Super quality color handouts, well prepared and executed

- Yes, with the exception of some slides not being included in the hand-out material.

- The handout did not match the presentation. It was disruptive to the presentation since people are looking for the right presentation to follow.

- The handout did not match up well with the slides so people spent too much time trying to find the right place. I suggest either not handing the document out until the end or making the document match closely the slides to be shown.

- Provide a list of abbreviations used in the slides as part of the handout.

6. How could we improve the workshop?

- While recording issues on the flip charts there was too much force fitting into three arbitrary categories. This meant that the true meaning of the comment was often lost or changed. Not grouping would have been better for this kind of “brainstorm”.

- For service companies to share details with operators only, could you set up a session where you have HAL addressing operators only, then SLB, etc.? as they do not want share statements with competitors. Sort of a dual track with other service sector people, NGO’s, GOV, consultant members of DeepStar working some other issues while service companies can have a one on one with a group of producers. At the end, producers then agree based upon all they have heard, that you redirect focus on specific R&D projects. Is this workable? Giving them confidential time with operators would open up for frank discussions.

- Perhaps have a session where various areas of interest could be discussed in smaller groups.

- Appears some operators were holding some things back.

- Divide into smaller group for discussion and present ideas to workshop.

- Would have been better to have had more discussion. It seemed like the discussion was dominated by the principal investigators. I gave input but it seems like very few others did. I am not sure if more people in the Forum did not have input (wanted to learn from study, not contribute to the direction of future work) or was limited by the format.

- I wasn't too clear on the agenda until I arrived at the meeting. An early agenda with an opportunity to suggest additional (or future) topics might have been useful.

- Overall, I thought the workshop was well conducted. I will be interested to see what comes from all the comments that were made during the discussion. I think that will be the true test of how successful the workshop was.

- Difficult to extract accurate/objective information from service companies. I would have liked a more open discussion.

Appendix D – Presentations on Drilling, Cementing and Completion Gaps from DeepStar Public Workshop on HPHT Technology Gaps (3/30/06)

DeepStar CTR 7501

Drilling and Completion Technology Gaps for HPHT Deepwater Wells

Workshop

March 30, 2006

by

Tom Proehl, Triton Engineering Services

Fred Sabins, CSI Technologies

Tom Williams, Maurer Technology Inc.

Drilling Assessment

Purpose

- HPHT Deepwater Drilling Technology Gaps
  - Identify
  - Understand
  - Prioritize

HPHT Definition

- 27,000 ft BML
- >350°F BHST
- 24,500 psi static BHP
- 4,000 and 7,500 ft WD
- Subsalt case for each WD

Methodology

- Analysis of Historical Well Data
  - Some data available
  - Failures, successes, limits
- Survey of Industry Service Providers
  - Standard limits and usages
  - Real limits and gaps
- Compare Industry Claims with Data

Industry Survey Method

- Develop survey
- Interview
- Identify physical drivers
- Identify impact of drivers
- Define SOA
- Define limits of existing skills, equipment and services
- Identify requirements to close gaps
- Quantify time, cost, technical to close gaps

Taxonomy of Technology Gaps

- Physical gaps
  - Is it physically possible to implement method or objective?
- Economic gaps
  - Is operation or method worth the cost?
- Regulatory gaps
  - Is it permissible by regulatory bodies?

Who Needs What?

- Operating Companies
- Drilling Contractors
- Service Companies
- Regulatory Agencies

Key Issues for Drilling

- Limited Evaluation Capability
- Limited Directional Capability
- Low ROP
- Well Control
- Non-productive Time

Drilling Technology Concerns

- Wellheads and Casing Hangers
- Drilling Fluids
- Directional Drilling
- LWD/MWD
- Openhole Logging
- Bits
- Inspection, QA/QC, and Standards

Data Sources

Baker	FMC	Halliburton	M-I	Schlum-berger	Smith	Technical Industries
		Bits			Bits	
Drilling Mud			Drilling Mud			
Drilling Systems		Drilling Systems		Drilling Systems	Drilling Systems	
						Inspection
LWD/MWD		LWD/MWD		LWD/MWD		
		Openhole		Openhole		
	Wellheads					

Drilling Cost

- Seven actual wells
- Good variation in wells
- Available technology drives cost
- Cost drives technology development
- Want to reduce time/cost with technology innovation

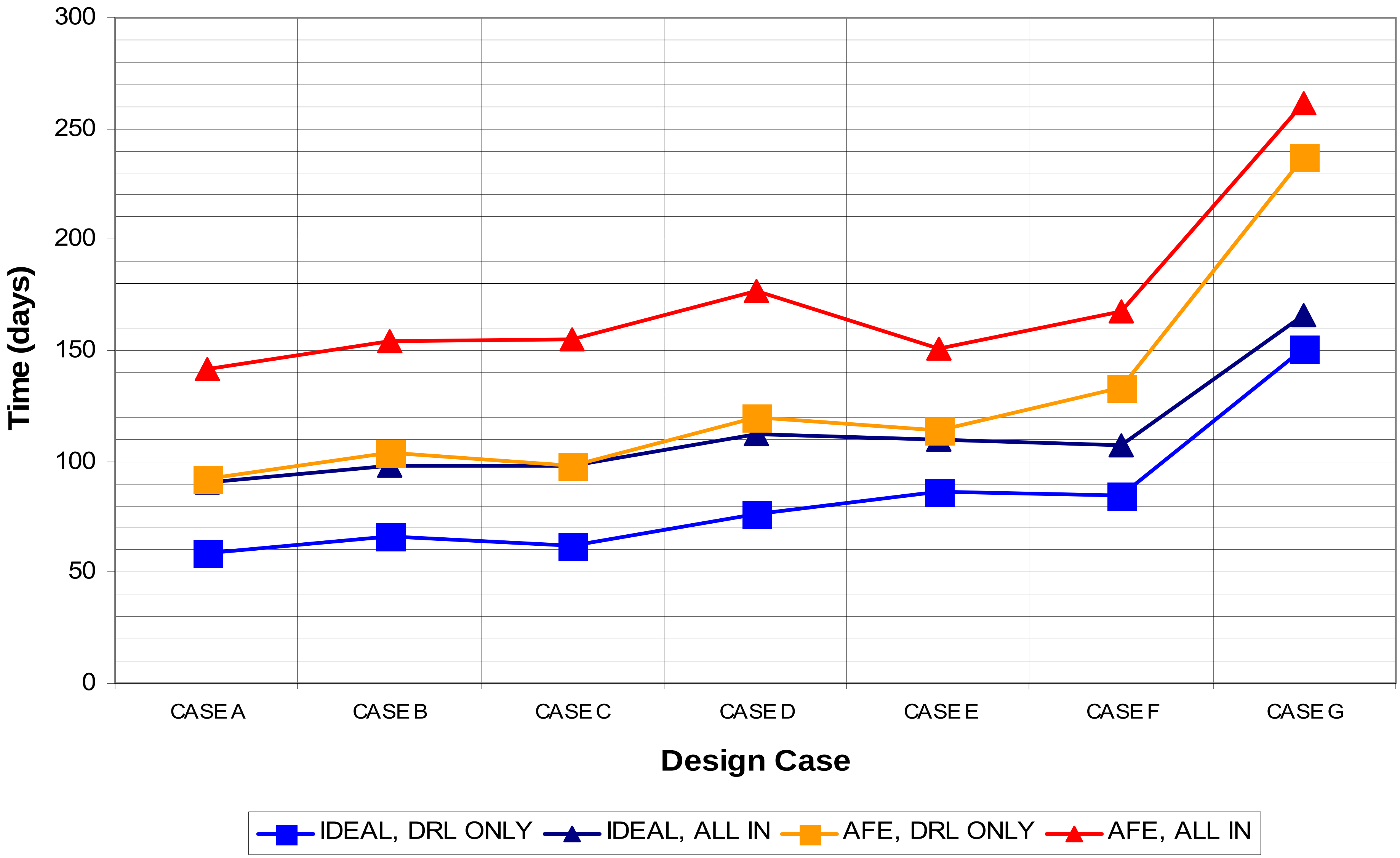
Design Cases

Case A	4,000' WD	GOM
Case B	7,500' WD	GOM
Case C	4,000' WD	GOM Subsalt
Case D	4,000' WD	GOM
Case E	7,500' WD	GOM Subsalt
Case F	7,500' WD	W. Africa
Case G	4,000' WD	S.E. Asia

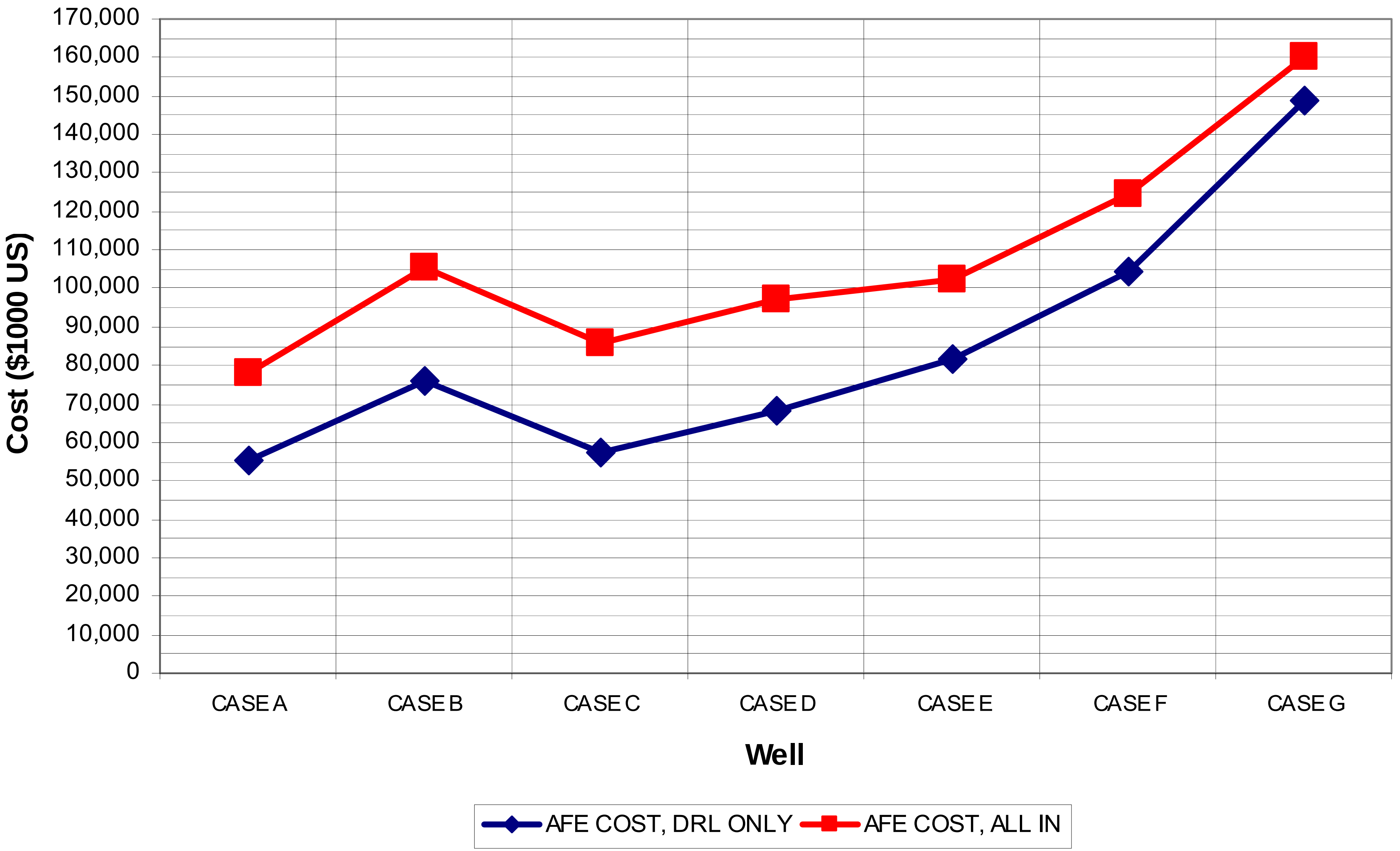
Design Cases

	CASE A	CASE B	CASE C	CASE D	CASE E	CASE F	CASE G	AVG	STD DEV
WELL DATA									
LOCATION	GOM	GOM	GOM	GOM	GOM	WA	SEA		
SALT?			S/S		S/S				
AIR GAP	100	100	100	100	100	100	100		
WATER DEPTH	4000	7500	4000	4000	7500	7500	4000		
BML DEPTH	27000	27000	27000	27000	27000	27000	27000		
TOTAL DEPTH	31100	34600	31100	31100	34600	34600	31100		
DRILLING TIME									
IDEAL DAYS	58.46	66.14	62.36	76.27	85.96	85.05	150.72	83.57	29.17
OPT INT CSG			4.23	4.23	4.23				
OPT DRLG LNR 1	11.11	11.11	11.11	11.11	11.71	14.33	7.94		
OPT DRLG LNR 2	13.25	13.25	13.25	13.25					
P&A	7.5	7.5	7.5	7.5	7.5	7.5	7.5		
TOTAL IDEAL TIME w/ OPTS	90.32	98	98.45	112.36	109.4	106.88	166.16	111.65	23.35
LTF	0.571	0.571	0.571	0.571	0.571	0.571	0.571		
TRIP SPEED (ft/hr)	695	695	695	695	695	695	695		
AFE DAYS	91.83	103.89	97.97	119.81	114.33	133.62	236.8	128.32	46.16
OPT INT CSG			6.64	6.64	6.64				
OPT DRLG LNR 1	17.45	17.45	17.45	17.45	18.4	22.51	12.5		
OPT DRLG LNR 2	20.81	20.81	20.81	20.81					
P&A	11.78	11.78	11.78	11.78	11.78	11.78	11.78		
TOTAL AFE TIME w/ OPTS	141.87	153.93	154.65	176.49	151.15	167.91	261.08	172.44	37.68
DRILLING COSTS ($1000)									
AFE COST	$55,469	$75,814	$57,260	$68,068	$81,452	$104,311	$149,048	$84,489	$30,469
OPT INT CSG			$4,671	$4,702	$4,263				
OPT DRLG LNR 1	$8,067	$10,537	$9,681	$9,692	$11,468	$14,601	$6,636		
OPT DRLG LNR 2	$9,086	$12,261	$9,236	$9,373					
P&A	$5,161	$6,756	$5,158	$5,177	$5,298	$5,385	$4,750		
TOTAL AFE COSTS W/OPTS	$77,783	$105,368	$86,006	$97,012	$102,481	$124,297	$160,434	$107,626	$25,548
SUMMARY COST INDICATORS									
COST per DAY ($1000)	$548.27	$684.52	$556.13	$549.67	$678.01	$740.26	$614.50	$624.48	$71.76
COST per DRLD FOOT	$2,881	$3,903	$3,185	$3,593	$3,796	$4,604	$5,942	$3,986	$946
RIG RATE MULTIPLIER for TOTAL	1.69	1.22	1.71	1.69	1.22	1.51	1.89	1.56	0.24

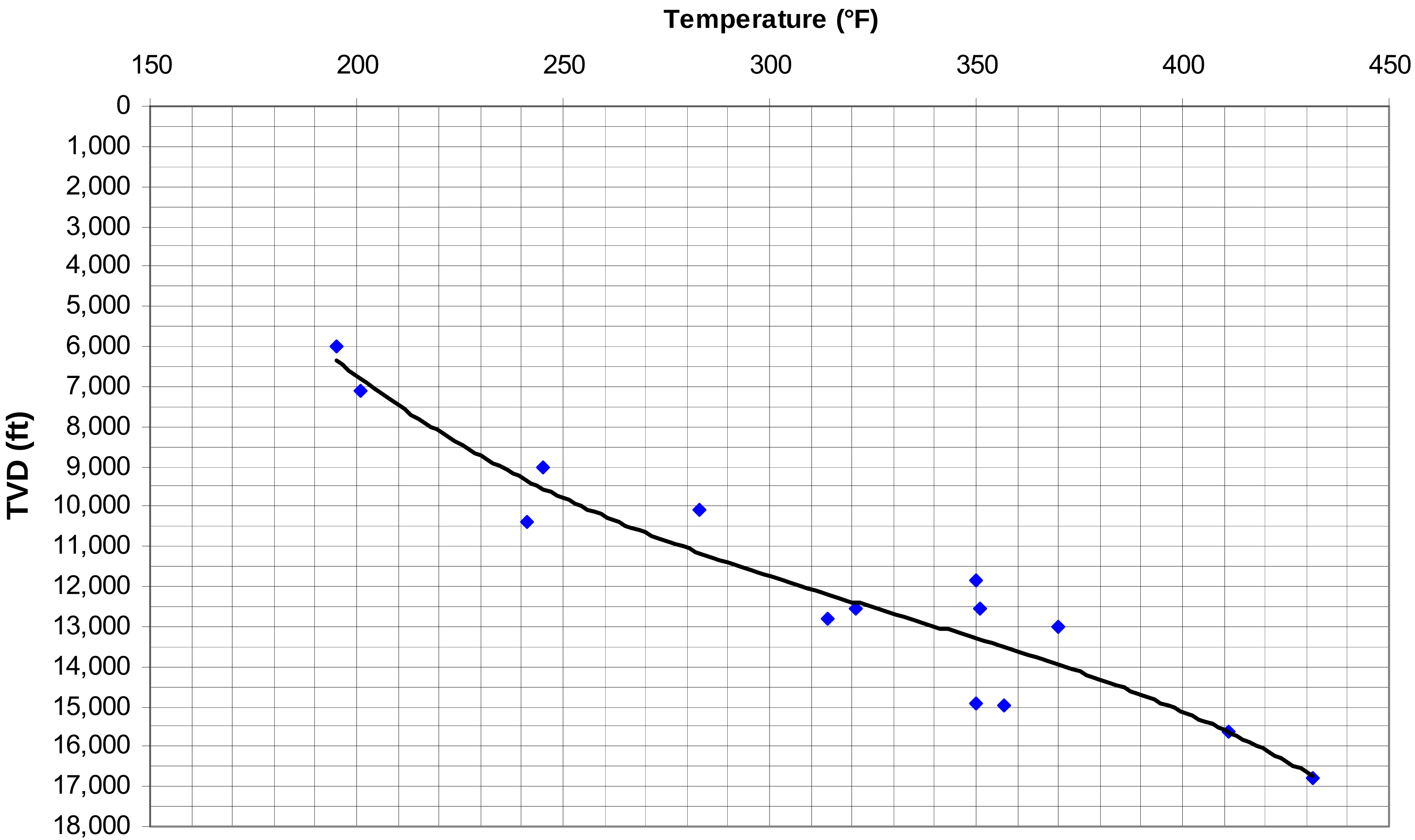
Design Cases – Operations Time



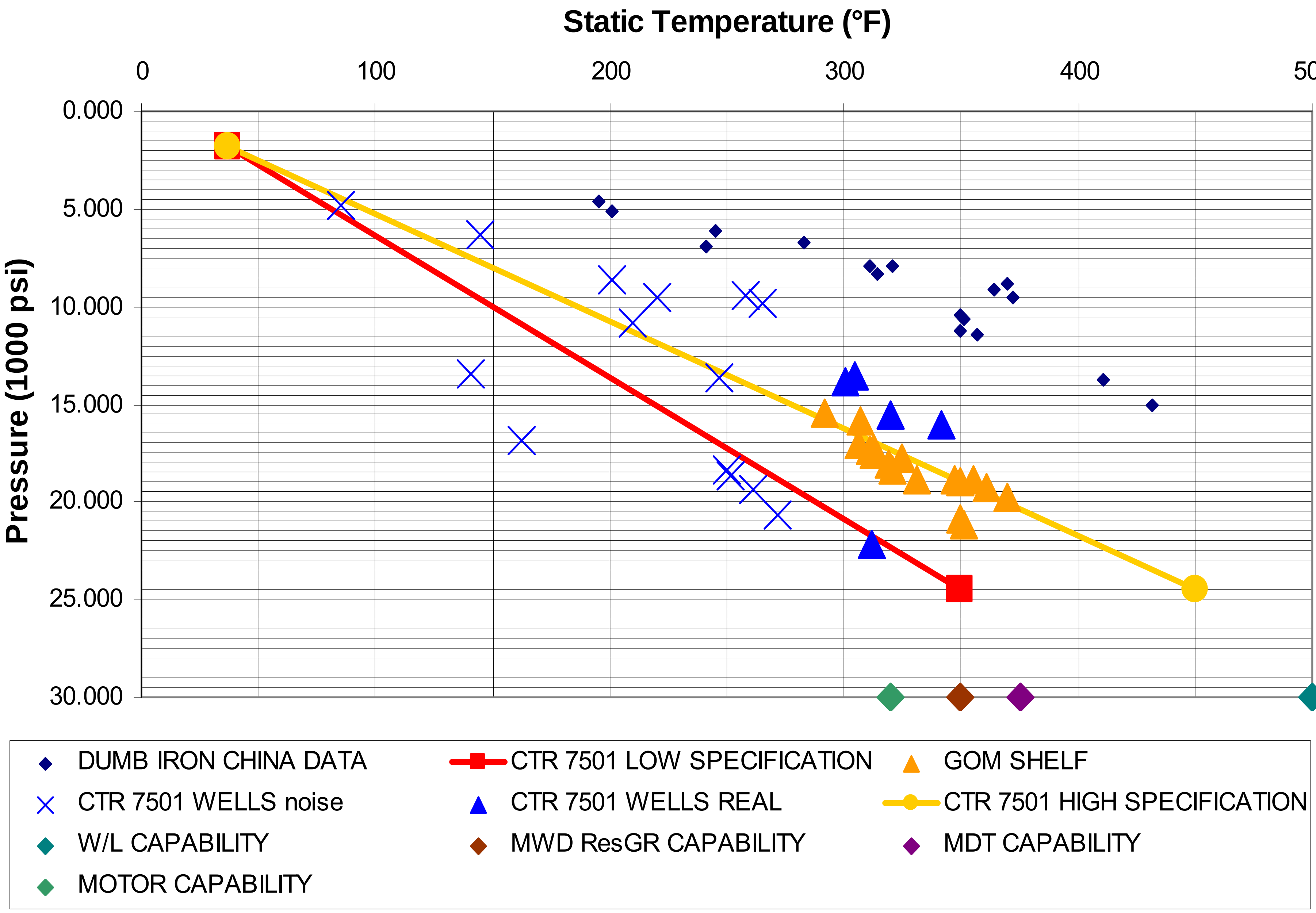
Design Cases – Cost



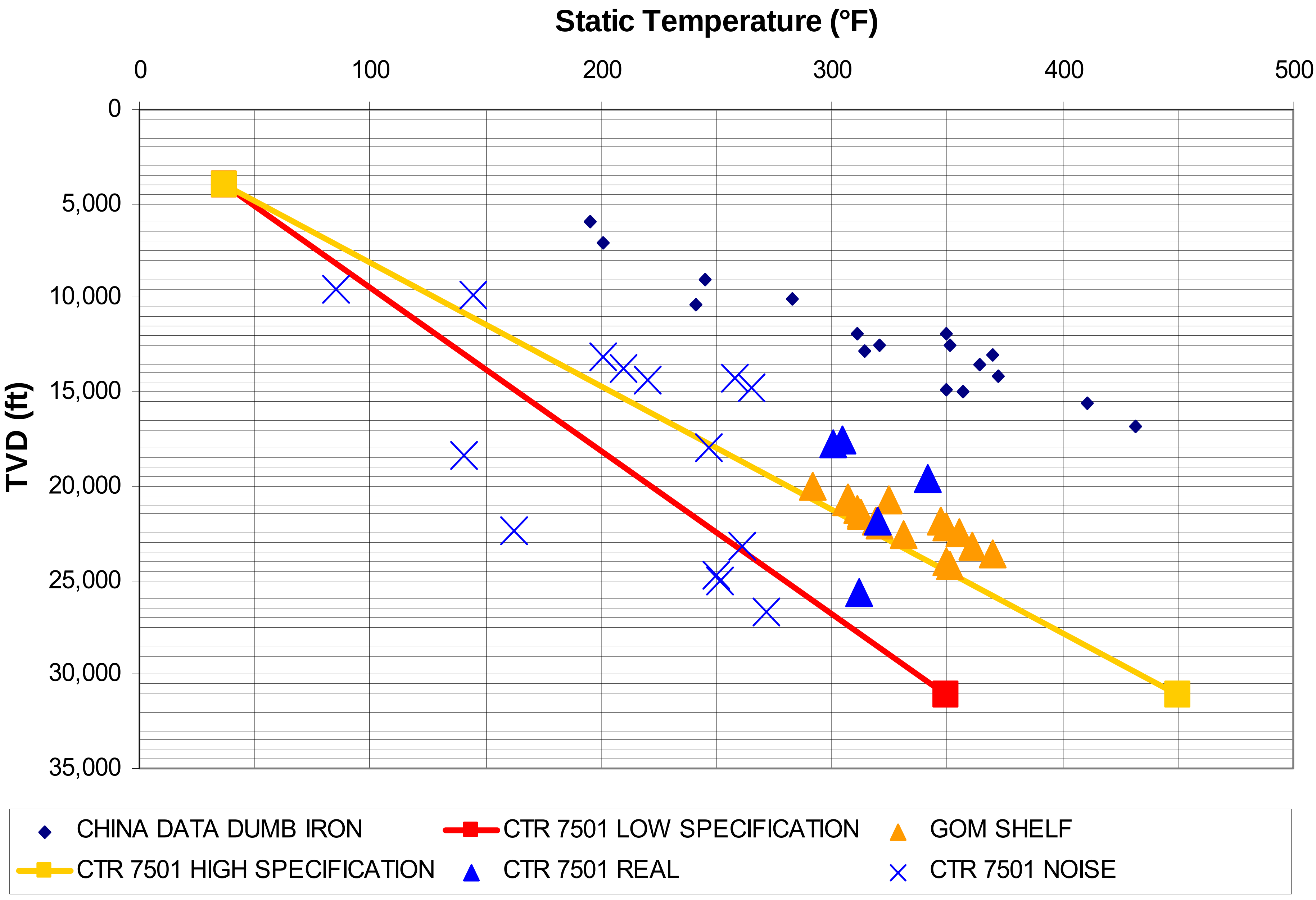
Yacheng Area Temperatures



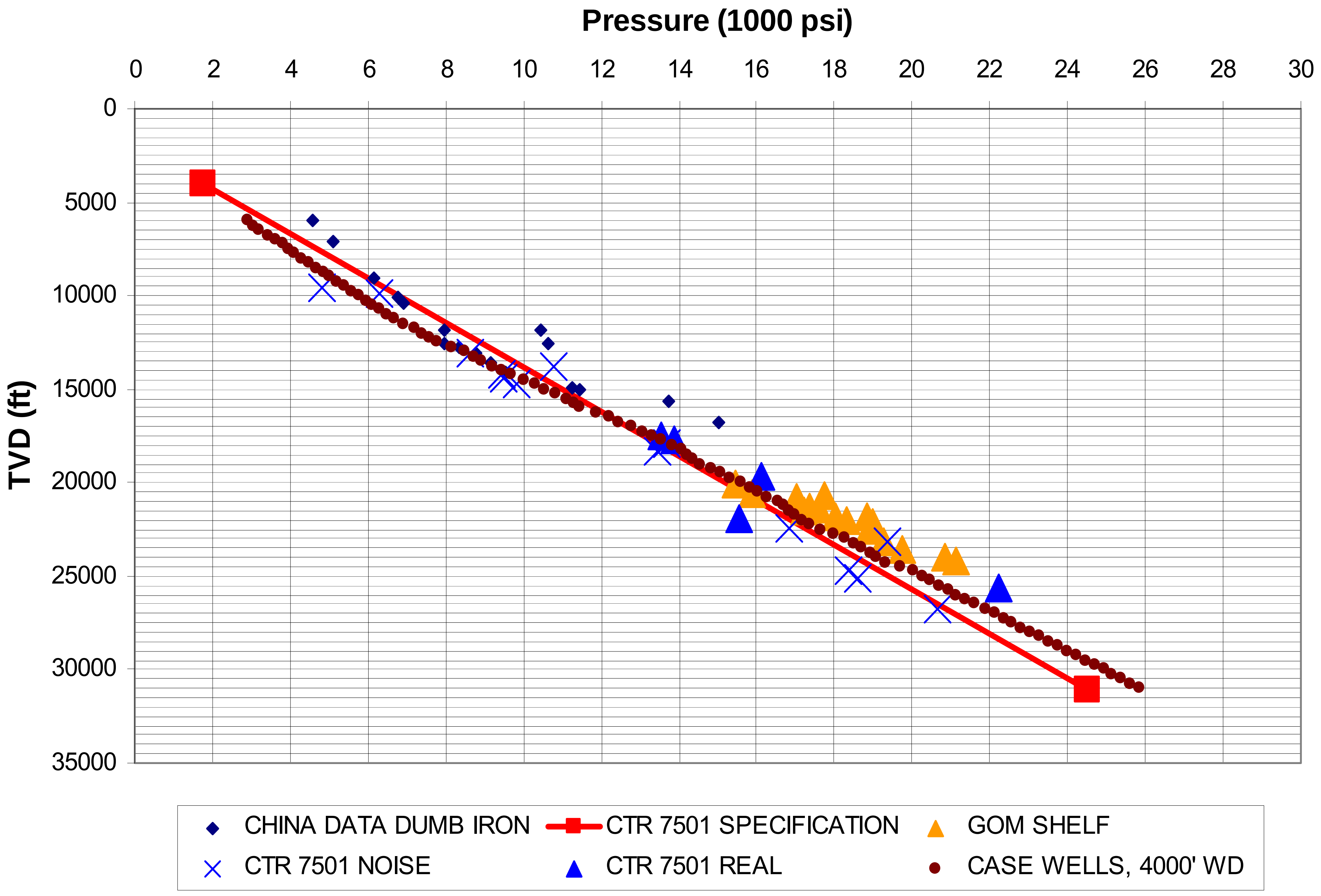
Temperature & Pressure Conditions



Temperature versus Depth



Pressure versus Depth



Drilling Gaps – Service Line Summary

	Pressure	Temp	Service
Wellheads & Casing Hanger *(Also addressed in HIPPS)*	15 kpsi	350°F	H_2S
Drilling Fluids ▪ Oil Base Mud ▪ Water Base Mud ▪ Synthetic	 30 kpsi 30 kpsi 30 kpsi	 500°F 500°F 500°F	 H_2S
Directional Drilling ▪ Motors ▪ Control/Steering ▪ Long Sections	 25 kpsi *See MWD*	 425°F *See MWD* 425°F	 300 hr 300 hr
LWD / MWD ▪ High Reliability ▪ Limit		 275°F 350°F	 H_2S H_2S
Openhole Logging ▪ All tools ▪ Limited Tools	 25 kpsi 25 kpsi	 350°F 450°F	 H_2S H_2S
Bits ▪ PDC & TSP ▪ Roller Cone Not Desirable	 30 kpsi	 500°F	

Wellhead and Casing Hanger

- Current Limits
  - Cost/maintainability, large cost for performance
  - Equipment limits – 15,000 psi with H_2S to 350°F
    - Metal-to-metal seals/elastomer
  - Size – five to six types should be adequate
- Gap Closure
  - $2 to $3 million new well heads
  - Need 25,000 psi and 450°F

Drilling Fluids

- Current Limits
  - Storage and mixing are adequate
  - Hole stability marginally handled
  - Cuttings removal, fluid stability good
  - Lab equipment, HSE currently addressing
  - Drilling Performance underway
- Gap Closure
  - Fluid properties could improve ROP
  - Facilities to test at 500°F and 30,000 psi
  - New methods for cooling drilling fluids at surface and help cooling LWD/MWD

LWD/MWD

- Current Limits – Gap Closure
  - Temperature limits 275–350°F; need 500°F
  - Seals, cost, hole size
  - Telemetry 20,000’ and 350°F
  - Power, batteries to 350°F with lithium and 400°F with mercury

Openhole Logging

- Current Limits – Gap Closure
  - Conveyance, special line and drill pipe to 32,000’
  - Equipment – 25 kpsi and 450°F; need 500°F
  - Measurements – 400°F to 450°F; need 500°F

Directional Drilling

- Current Issues – Gaps
  - Drilling Equipment/Stabilizers – multiple failures in E&P drilling
  - Electronics/Telemetry – same as LWD/MWD up to 350°F; need 500°F
  - Vibration is a complicating issue
  - Drilling Motors – turbine and Moyno upgrades are required; need 30 kpsi and 500°F

Drill Bits and Cutters

- Current Limits – Gaps
  - Types – ongoing research (DOE), problem is cost, tight machining replace seals
  - Formations – turbines with PDC/TSP bits best
  - Size Availability – custom-build for application increases cost
  - Design Limits – none now, vibration is biggest issue for drillstring equipment optimization

Inspection, QC, and Standards

- Current Limits – Gaps
  - Standards – update API for wellheads at 25 kpsi, NACE standards to 500°F
  - Types – current types are sufficient
  - Cataloging and Reporting – driven by industry groups

The "Prize"

- Money saved by avoiding methods and operations that are unnecessarily slow and cumbersome
- Slow and cumbersome operations are eliminated by closing technology gaps

Key Technology Gap: MWD/LWD Well Path Control

- Assume:
  - Vertical well – BHA maintains vertical path
  - Temperature >300°F, MWD/LWD unreliable
  - 500' survey interval – 21,000–31,000' TD
  - Four bit trips required
  - 15 survey trips required
  - Need a log on each trip

Costs (No Smart Tools)

- Tripping: 23.4 days $14,600k/well
- Logging: ±$250k/run $5,000k/well
- Total: ±$20,000k/well (increm. to AFE)

Alternative: Use Currently Available Smart Tools to Destruction

Costs (Smart Tools)

- Use currently available “smart” tools
- 729 ft MDBF: LWD/MWD
- Some ability to alter well path to vertical
- ±14 trips required
- Cost: 21.8 days; $13,600k ($6,400k or 30% savings over drilling blind)

The Way Forward

- If you can measure it, you can manage it
- If you don't measure it, you need luck
- Good luck is what happens when preparedness meets opportunity

Options

- Do nothing – await developments
- Develop technology yourself
- Develop technology with small consortia
- DeepStar-scale JIP effort

Analysis – The Stakes Justify Substantial Effort in R&D

Concepts and Possibilities

- Expand JIP to include shelf drillers
- Develop detailed database on all HTHP tech failures
- Monitor/measure improvement in tool performance
- Optimize procedures for applying tools
- Integrate research efforts
- Focus on cooperation, application, feedback
- Engage/empower an engineer to champion HPHT gaps

Cementing Assessment

Cementing Assessment

- Project Team
  - DOE, MMS
  - Deep Trek participants: Conoco, Anadarko, Dominion, Chevron, BHP
  - Service Companies
- Address four areas
  - Primary cementing
  - Squeeze cementing
  - Tieback cementing
  - Plug cementing

Primary Cement Assessment

- Current Issues – Gaps
  - H_2S and CO_2 corrosion issues – need to be up to 500°F, and HP (longterm integrity)
  - Bond Logs and Evaluation – 350 to 400°F now; need 500°F
  - Plugs and floating equipment – 400°F and 5 kpsi now; need 500°F
  - Openhole ECP/Liner Top packers – 400°F and 20 kpsi; need 500°F

Primary Cement Assessment

- Current Issues – Gaps
  - Specialized cements
    - Saturated salt
    - Penetrating sealants
  - Mechanical Property Modification
    - Tensile strength increases – up to 700 psi; need 2000 psi
    - Expansion – now 300°F; need 500°F
    - Bond to pipe, formation – now 500 psi; need 2000 psi
  - Expandable Tubulars – now 20 kpsi and 400°F; need 500°F

Primary Cement Assessment

- Current Issues – Gaps
  - Hole strengthening/stability
    - Currently have polymers, membrane forming, solids-free penetrating fluids
    - 350°F; need 500°F

Squeeze Cementing

- Current Issues – Gaps
  - All issues are with primary cementing
  - Lab testing at BHST/BHP
    - Standard compatibility well fluids testing
  - Solids-free materials for penetrating – now 350°F, need 500°F
  - Squeeze packers – now 400°F; need 500°F
  - Casing leaks – some current materials limit of 400°F; need 500°F

Tieback Cementing

- Current Issues – Gaps
  - APB in between casing, current research ongoing (Chevron)
  - Pressure maintaince for tieback casing design
  - Friction pressure testing and modeling at HPHT conditions

Plug Cementing

- Current Issues – Gaps
  - Tools needed (plug catcher, diverter sub, tubing release tool), 350°F; need 500°F
  - High-strength materials for kick off/ laterals – now 5 kpsi; need 10 to 15 kpsi
  - Solids-free sealant for borehole strengthening – now 350°F; need 500°F

Completion Assessment

Completion Assessment

- Most difficult area for DeepStar requirements
- Wide range of issues that require individual attention
  - Chemicals
  - Production issues
  - Equipment
  - Mechanical perforation
  - Testing

Data Sources

Baker	Well Dynamics	TerraTek	BJS	Schlumberger	HES	Power Well
Completion Fluids						
						Well Testing & Flowback
			Stimulation	Stimulation	Stimulation	
Flow Assurance						
				Instrumentation		
		Perforating				
Completion Equipment	Smart Technology		Packers Elastomers	Packers Elastomers	Packers Elastomers	
Well Testing				Downhole Equipment Subsea Systems Surface Equipment		

Completion Fluids

- Current Limits – Gaps
  - Hole Stability – current 20 ppg, pore pressure frac pressure almost equal, additive to control density variation needed
  - Corrosivity – now not a problem, new metals need additional control
  - Formation compatibility – up to 400°F; need up to 500°F (Stim Lab is designing HPHT equipment)

Stimulation

- Current Limits – Gaps
  - Proppants – 400°F and 25 kpsi, need coatings or new materials to prevent imbedding, frac conductivity, crushing
  - Transport Fluids – current technology is OK, need weighted brines to reduce wellhead pressure
  - Wellhead Control – wellhead isolation equipment to address treating pressure

Flow Assurance

- Current Issues – Gaps
  - Deployment – currently simplistic, need automated injection, high injection pressures
  - Injection – unknowns until HPHT wells produced; higher pressures for umbilical lines and injection subs
  - Areas of Control – 450°F at bottom, 275°F well head; need 500°F bottom hole and 300°F+ at surface
  - Well head issues again

Perforating

- Current Limits – Gaps
  - Equipment – all works to 450°F; need 500°F
    - Firing heads
    - Initiators
    - Primer cord
    - Shape charges
    - Gun case

Completion Equipment

- Current Issues – Gaps
  - Equipment – sealing is major issue with elastomers, dynamic design at 400°F; need 500°F
  - Operation – SSCV pressure activated, electro-magnetic needed, downhole power needed
  - Measurement – need 500°F capability
  - Casing damage – setting packers without slips necessary

Smartwell

- Current Issues – Gaps
  - Similar to equipment section
  - Equipment – need actuators and sensors that will work at 20 kpsi and 500°F
  - Maintenance – intervention processes lower cost of repair, calibration, replacement

Well Testing

- Current Issues – Gaps
  - Big topic
  - Surface Equipment Design (volumes, flow periods etc.)
  - Fluid Engineering – pressure port plugging, tool reliability, negative impact on test strings
  - Circuit Technology – pressure and testing requirements
  - Monitoring Technology – continuous monitoring produced fluids remote

Packers/Elastomers

- Current Issues – Gaps
  - More exotic alloys and components are needed
  - Compatibility of tubing, packer, well fluids required
  - Polymers, seals to withstand corrosive, HPHT conditions, chemical performance
  - Metal-to-metal seal may replace elastomers
  - Surface testing procedures needed

Wireline Testing

- Current Issues – Gaps
  - Tools and systems to deliver wider range of data
  - Indirect measurements need to be refined
  - Data requirements prioritized
  - Equipment to withstand 250–450°F for long periods of time, non-conductive metals

The End

Appendix E – Presentation on Challenges, Opportunities, and the Way Forward from DeepStar Public Workshop on HPHT Technology Gaps (3/30/06)

DeepStar CTR 7501
Drilling and Completion Technology Gaps for HPHT Deepwater Wells

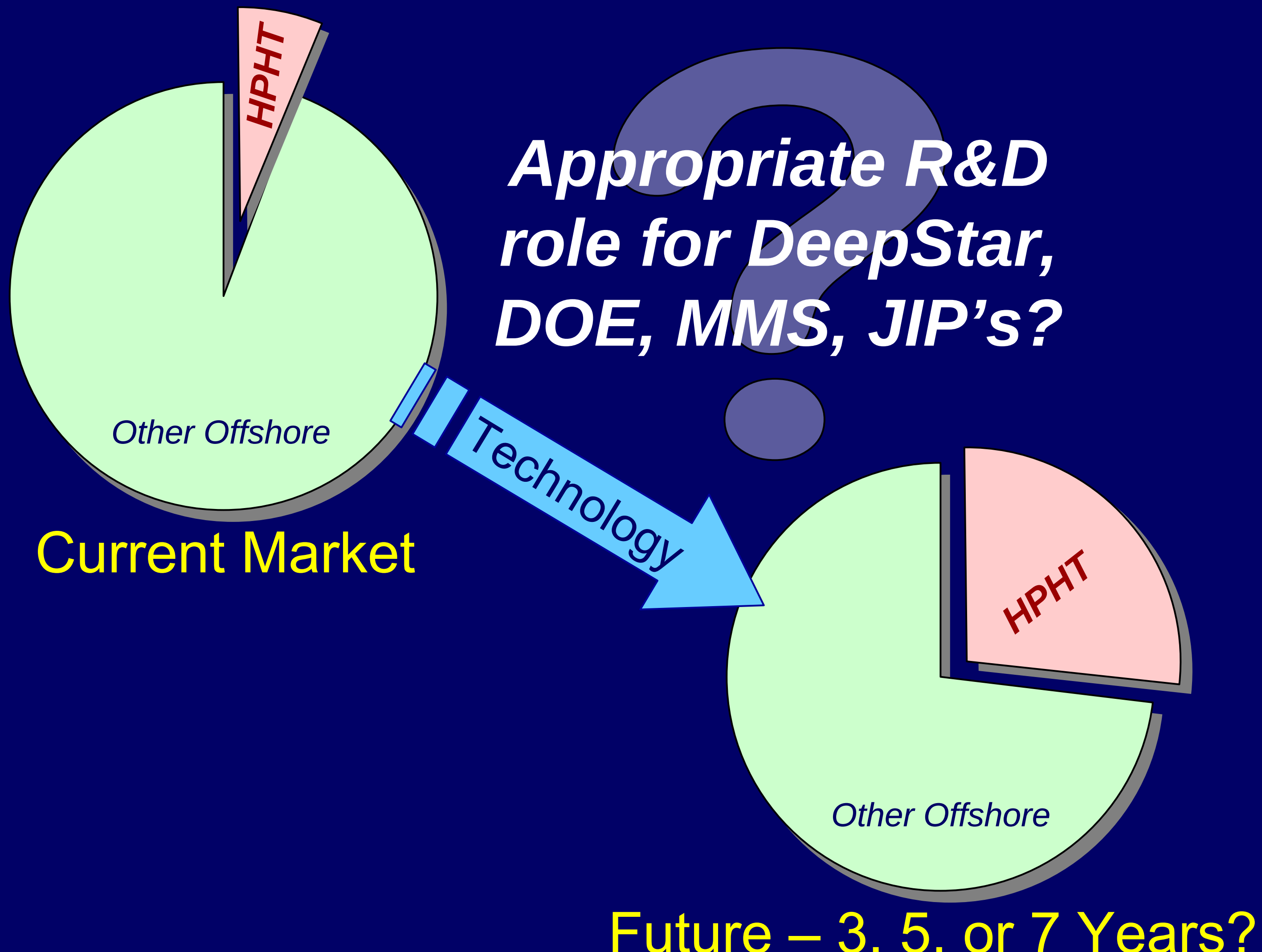
Workshop

Discussion

Challenges, Opportunities and Way Forward

March 30, 2006

Bridging the Technology Gap



Who Needs What?
Investment Risks and What is at Stake

- Operating Companies
- Drilling Contractors
- Service Companies
- Regulatory Agencies

Why Should Service Companies Invest?

- Will the size of the market justify the investment?
- What is their timing horizon?

Why Should Operators Invest?

- Easy prospects are gone
- Huge resource

Is There a Role for DeepStar?

- Are JIPs the way to go? They have a lot of advantages for everyone, but require free flow of information and data.

What is Best and Most Appropriate Role for Government?

- R&D
- Incentives
- Regulatory

Options

- Do nothing – await developments
- Develop technology yourself
- Develop technology with small consortia
- DeepStar-scale JIP effort
- Government co-funding

Analysis – The Stakes Justify Substantial Effort in R&D

The “Prize”

- Money saved by avoiding methods and operations that are unnecessarily slow and cumbersome
- Slow and cumbersome operations are eliminated by closing technology gaps

Recommended Projects

Drilling Gaps/Projects

- Electronics and Sensors (funded)
  - DOE, Deep Trek and DEA
- Inclinometer (MWD/LWD)
  - 2007 budget
- Systems look
  - Bits, mud, motors, drill string dynamics
  - Cooling to improve MWD/LWD
  - Best practices
  - Manage of ECD's

Drilling Gaps / Projects

- Improve MWD motor and turbine design
- Rock mechanics to improve ROP
- Mud system for friction, thermal properties, control density, ROP
- Text fixtures and equipment
- Nanotechnology
- Solid-state battery (JIP)
- HPHT turbine generator
  - DOE to Dexter Magnetic Tech

Drilling Gaps/Projects

- Wellheads for 25 kpsi and 450°F H_2S
- Review/recommend revision of API, NACE and ASME specs for HPHT

Cemanting Gaps/Projects

- H_2S and CO_2 issues with sealants
- Alternative sealants
  - Formation consolidation
  - High mechanical properties
- Bond logs and evaluation
- Lab testing procedures and equipment
- APB in tiebacks
- Pressure maintenance for tiebacks

Completion Gaps/Projects

- Completion fluids with improved thermal properties
- Modified completion equipment
  - Dynamic sealing, chemical injection, static sealing, electronic and sensor tech, intervention tech
- Stimulation
  - High-strength proppants, gels with heavy weight brines, well heads for 30 kpsi service

Completion Gaps/Projects

- Flow Assurance
  - New completion equipment for injection
  - Hydrate and scale inhibition
- Smartwell (already funded)
  - Batteries and electronics
- Packers
  - Elastomers for 500°F and 30 kpsi
  - Metallurgy for 500°F and 30 kpsi
  - Metal-to-metal seals

Completion Gaps/Projects

- Elastomers
- Wireline Testing
  - HPHT electrical insulator materials
  - Inferential test methods
  - Continuous duty HPHT electronics
- Well Testing
  - Packer and downhole equipment
  - Lab test equipment for HPHT conditions

Conclusions - Discussion

- HPHT wells can be drilled, but with limitations
- Economic impediments include equipment, process and regulatory components
- Controlling risks? They must first be defined!!
- Existing gaps support large R&D funding
- Collaboration is critical to success

Discussion Points

- Review report and discuss intra-company
- Way Forward: DeepStar Role?
- Way Forward: Role(s) for other players?

Recommendations

- Expand JIP to include shelf drillers
- Develop detailed database on all HPHT tech failures
- Monitor/measure improvement in tool performance
- Optimize procedures for applying tools
- Integrate research efforts
  - Prioritize and Consider Funding Study's Recommended R&D Projects
- Focus on cooperation, application, feedback
- Engage/empower an engineer to champion HPHT gaps

The Way Forward

- If you can measure it, you can manage it
- If you don't measure it, you need luck
- Good luck is what happens when preparedness meets opportunity
- The main step toward preparedness is measurement!!!! Quantify industry experience first!!!!

The End

Appendix F – Presentation Summarizing MMS Project 519 on HPHT Technology Gaps (by Tom Williams at MMS Overview Meeting on 5/23/06)

DeepStar CTR 7501
Drilling and Completion Technology Gaps for HPHT Deepwater Wells

Participants: DeepStar, MMS, DOE, Triton Engineering Services, CSI Technologies, Noble Technology Services

Challenges, Opportunities and Way Forward

MMS Overview Meeting May 23, 2006

Purpose

- HPHT Deepwater Drilling and Completion Technology Gaps
  - Identify
  - Understand
  - Prioritize

Project Completed

- 1/30/06 Report vetted by DeepStar
- DeepStar Review 3/2/06
- Workshop 3-30-06
- Summary and Recommendations
- Report includes technical limits and needs for drilling, cementing, fluids, completions
- This presentation includes recommended projects

HPHT Definition

- 27,000 ft BML
- >350°F BHST
- 24,500 psi static BHP
- 4,000 and 7,500 ft WD
- Subsalt case for each WD

Participants

Co-funding and data were provided by:

- DeepStar Consortium
  - DeepStar Operators and Service Companies
- U.S. DOE National Energy Technology Laboratory
- Minerals Management Service

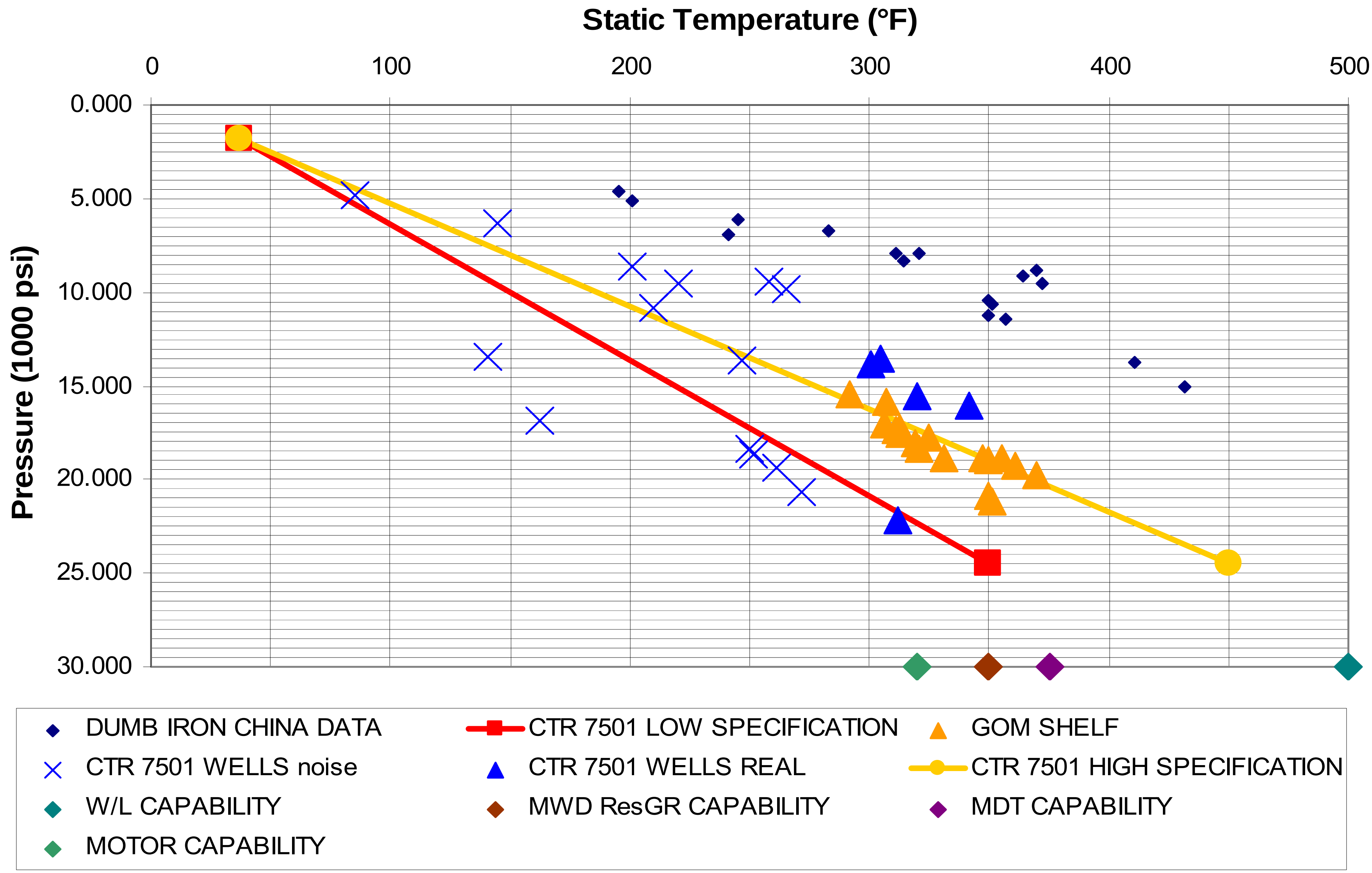
Study Methodology

- Identify State of the Art, including on going R&D, worldwide activity
- Analysis of Historical Well Data
  - Some data available
  - Failures, successes, limits
- Survey of Industry Service Providers
  - Standard limits and usages
  - Real limits and gaps
- Compare Industry Claims with Data

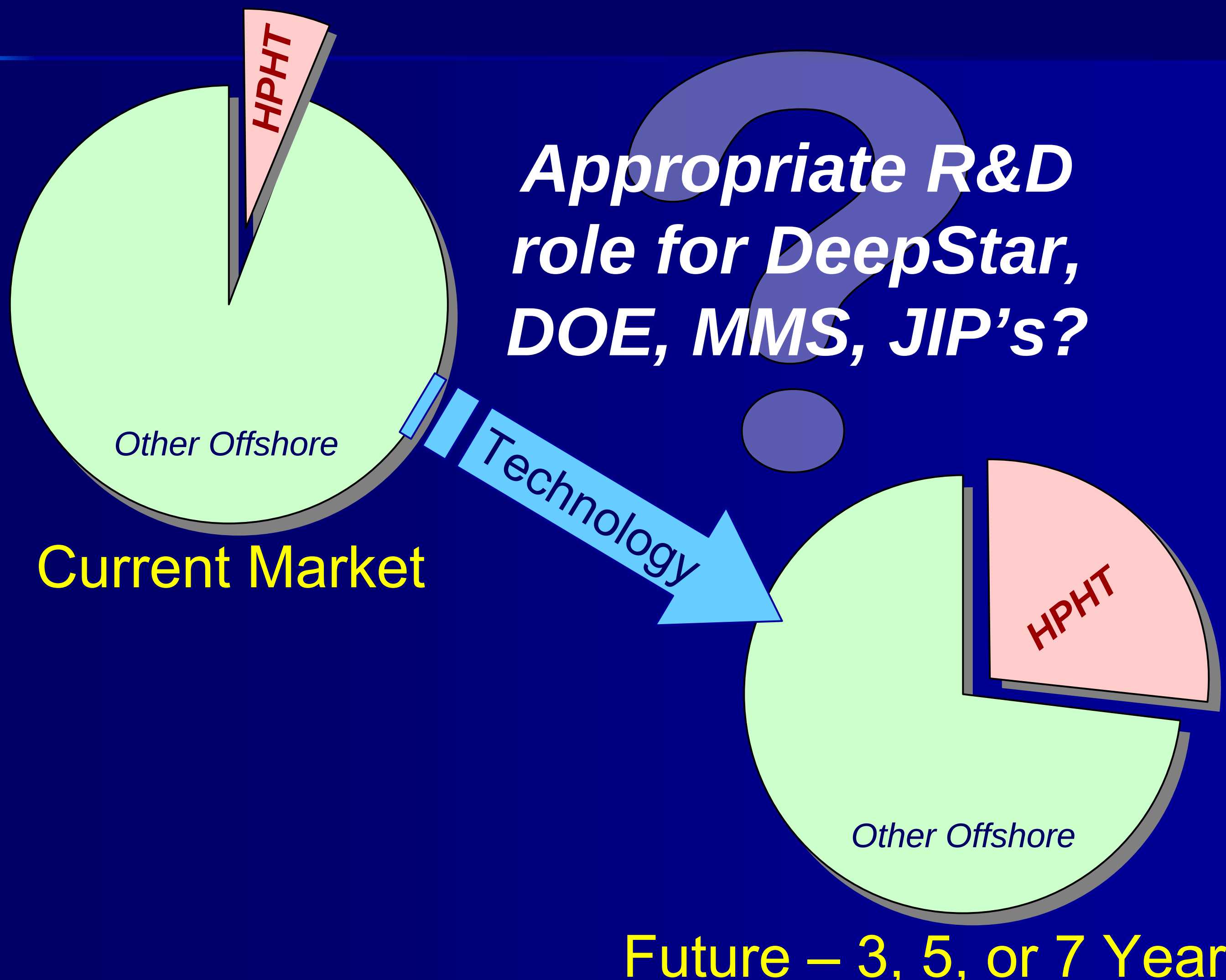
Industry Survey Method

- Develop survey
- Interview
- Identify physical drivers
- Identify impact of drivers
- Define limits of existing skills, equipment and services
- Identify requirements to close gaps
- Quantify time, cost, technical to close gaps

Temperature & Pressure Conditions 35 wells (31 DW, 4 shelf)



Bridging the Technology Gap



LWD/MWD Limits

- Current Limits – Gap Closure
  - Temperature limits 275–350°F; need 500°F
  - Seals, cost, hole size
  - Telemetry 20,000 psi and 350°F
  - Power, batteries to 350°F with lithium and 400°F with mercury

Options Presented at the Workshop

- Do nothing – await developments
- Develop technology yourself
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- DeepStar-scale JIP effort
- Government co-funding

Analysis – The Stakes Justify Substantial Effort in R&D

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- Slow and cumbersome operations are eliminated by closing technology gaps

Recommended Projects

Drilling Gaps/Projects

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- Alternative Sealants
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Completion Gaps/Projects

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The Way Forward

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- The main step toward preparedness is measurement!!!! Quantify industry experience first!!!!

Workshop Recommendations for Drilling

- Accurate measurements and documentation of what is failing in HPHT wells.
  - Failure mechanisms for LWD/MWD, RSS, and motors. This is necessary to accurately define the HTHP “prize”, to focus and direct research efforts, and to provide a baseline for performance improvements associated with application of HTHP research products.
- Effective means to control downhole pressures is critical– BOP’s, seals, materials, APB.

Needs/Comments from Workshop Attendees

- Participation in API RP 6
- H2S is a critical concern. In deeper wells, assume the well is sour. Materials are needed, including metals, cements, and seals.
- Annular pressure buildup (APB) is a critical issue. Need the ability to monitor integrity of tubulars. Vacuum-insulated tubing isn't a good answer. Some other alternatives should be considered.

Needs/Comments from Workshop Attendees

- Completion needs are show-stoppers. We can drill these wells (maybe not cost-effectively), but cannot complete and produce many HPHT wells (including deep shelf wells). The industry lacks adequate:
  - BOPs, Trees, Hardware, DH Electronics
- Need improved analytical models to aid in sizing equipment.
- Inability to evaluate xHPHT wells prevents proper completion and production designs.
- Consensus recommended a JIP on HPHT Data Mining.

The End