Oil & Natural Gas Technology

Development and Application of Insulated Drill Pipe for High Temperature, High Pressure Drilling

Final Technical Report
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ABSTRACT:

This project aimed to extend the insulated drill pipe (IDP) technology already demonstrated for geothermal drilling to HTHP drilling in deep gas reservoirs where temperatures are high enough to pose a threat to downhole equipment such as motors and electronics. The major components of the project were: a preliminary design; a market survey to assess industry needs and performance criteria; mechanical testing to verify strength and durability of IDP; and development of an inspection plan that would quantify the ability of various inspection techniques to detect flaws in assembled IDP. This report is a detailed description of those activities.

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1. EXECUTIVE SUMMARY

Hydrocarbon reservoirs that produce high drilling temperatures – both on the surface and in particular downhole – have historically driven the cost of reaching these reservoirs to a level that precludes any economic benefits. Reservoirs where either or both high temperatures and high pressures produce significant problems in drilling have become known generically as HTHP (high-temperature, high-pressure), and are increasingly common, especially in deep gas drilling. Unacceptable failure rates—caused by premature failure of both surface equipment and downhole equipment—are typical of wells in these reservoirs and the more costly of these failures include downhole motors, logging-while-drilling (LWD) and measurement-while-drilling (MWD) tools, drill bits, and other tools that incorporate hydraulic seals and electronic components. Drilling fluid properties can also deteriorate at high temperatures, resulting in an inability to carry the cuttings and promoting higher wear rates on drill bits due to the higher temperatures at the bit face. This latter effect is particularly acute with bits having pressure seals. Additionally, corrosion rates can increase exponentially at elevated temperatures, resulting in premature failure of even conventional drilling components such as drill pipe and drill collars. Finally, steel alloys used for drill pipe can lose 8-10% of their yield strength at temperatures above 450^{o}F.

Each of the problems mentioned above can be addressed by individual technology developments, but this R&D process can be very costly in both time and resources. An alternative approach is simply to control the temperature of the downhole environment so that existing drilling technology can more easily survive in this harsh environment. Insulated drill pipe (IDP) enables management of the drilling fluid temperature at the bottom hole assembly (BHA) and provides a more favorable environment.

In conventional rotary drilling, fluid circulates down the steel drill pipe, passes through the bit to clean the hole-bottom, and returns, carrying the cuttings, up the annulus between the pipe and borehole. Because the drill pipe is an effective counter-flow heat exchanger, drilling fluid temperatures inside and outside the pipe are very similar to each other at any given depth (see Figure 1 – the left-hand side of each curve is temperature inside the drill pipe and the right-hand side is temperature in the annulus between the drill pipe and wellbore). Fluid temperatures also tend to follow the formation temperature. In a given formation, downhole temperatures are affected by many drilling parameters – fluid flow rate, rate of penetration, fluid properties, bit-jet sizes, and the like – but sensitivity studies have shown that these factors are minor in comparison to the thermal conductivity of the drill pipe. Figure 1 also shows the calculated

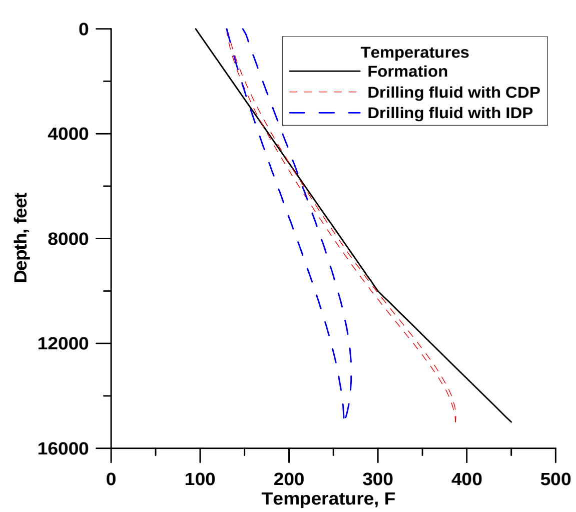

Figure 1 – drilling fluid temperatures with IDP and CDP

temperature reduction with IDP compared to conventional drill pipe (CDP) in a 15,000 foot gas well, with 4.75” bottom-hole diameter, assuming that the well is drilled with water-based mud over a period of 50 days. Thermal properties for IDP are taken from those of existing 3.5” IDP. Drilling parameters and formation temperatures used in these calculations are based on those in an actual South Texas gas well. This performance is discussed in more detail later, but the crucial factor is that IDP provides a significantly lower bottomhole temperature than conventional drill pipe.

To meet this project’s objective of extending IDP use into deep gas drilling, a two-phase project was originally proposed: Phase 1 would be preparatory, including a preliminary design for IDP, mechanical testing of that design, development of an inspection plan for the design, and a market survey to assess industry’s needs and concerns; while Phase 2 would build on this work to fabricate 12-15 joints of prototype IDP (based on any design changes suggested by the mechanical testing and market survey), use the prototype pipe for drilling in an actual HTHP well, and confirm the thermal performance with a field test in a hot well (either geothermal or hydrocarbon). The market survey was inconclusive, however, with respect to industry needs and concerns (described in detail in the body of the report), so the project was ended at the conclusion of Phase 1.

The Phase 1 work described in detail in this report comprises these four major activities:

- Produce a preliminary design: Drill Cool Systems (DCS) submitted a preliminary design, based on existing drill pipe, to DOE for approval of the basic approach to construction of IDP.

- Perform mechanical testing that verifies IDP’s strength and ruggedness: It is clearly necessary to assure a potential customer that the extra steps involved in building IDP have not compromised its strength and durability relative to conventional drill pipe. An extensive mechanical testing program demonstrated IDP’s undiminished performance.

- Design an inspection program that will quantify the ability to detect flaws in assembled IDP: If there is a mechanical flaw in the drill pipe body before insertion of the insulation liner, it cannot be seen by conventional visual inspection. An inspection program was designed to evaluate the ability of various techniques to detect such flaws.

- Run a market survey to identify industry concerns about IDP and to choose the optimum size pipe for industry needs: The industry is generally unfamiliar with the concept of IDP, and is often resistant to new technology. A market survey attempted to identify their concerns and also to predict where the principal markets might be, so that the prototype IDP would be built in an appropriate size.

In the organization of this report, each of these topics is discussed with individual sub-heads of “Methods”, “Results and Discussion”, and “Conclusions”, and there is a “Conclusions” section for the complete report.

2. INTRODUCTION AND BACKGROUND

The Master Announcement for this funding opportunity presents an excellent statement of the problem, "Extremely high temperatures (>400^{o}F), exceptionally high pressures (>15,000 psi), exceedingly hard rock, and highly corrosive gases all combine to create a very hostile environment for well drilling and completion. These conditions lead to material and electronic failures, increased wear on equipment, and increased technical and safety risk due to an inability to monitor downhole conditions. "

Hydrocarbon reservoirs that produce high drilling temperatures – both in surface equipment and in particular downhole – have historically driven the cost of reaching these reservoirs to a level that precludes any economic benefits. Unacceptable failure rates—caused by premature degradation of both surface equipment and downhole equipment—are typical of wells in these reservoirs and the more costly of these failures include downhole motors, logging-while-drilling (LWD) and measurement-while-drilling (MWD) tools, drill bits, and other tools that incorporate hydraulic seals and electronic components. Drilling fluid properties can also deteriorate at high temperatures, resulting in an inability to carry the cuttings and promoting higher wear rates on drill bits due to the higher temperatures at the bit face. This latter effect is particularly acute with bits having pressure seals. Additionally, corrosion rates can increase exponentially at elevated temperatures, resulting in premature failure of even conventional drilling components such as drill pipe and drill collars. Finally, steel alloys used for drill pipe can lose 8-10% of their yield strength at temperatures above 450^{o}F.

Each of the problems mentioned above can be addressed by individual technology developments, but this process can be very costly in both time and resources. An alternative approach is simply to control the temperature of the downhole environment so that existing drilling technology can more easily survive in this harsh environment. Insulated drill pipe provides a means to deliver much cooler drilling fluid to the bottom hole assembly (BHA) allowing these components to successfully function in a more favorable environment.

Insulated drill pipe has a long history. Sandia National Laboratories worked on this concept in the early 1980s for application to the Magma Energy Program[1]. Thermal and mechanical analyses were done at Sandia in the 1980s. Contracts for feasibility studies and preliminary designs of double-wall IDP were placed with two companies experienced in manufacturing insulated tubing for steam injection, but a grant from the California Energy Commission was rescinded at about the same time as the DOE ended the Magma Energy Program. The project lay dormant until the mid-1990s, when Drill Cool Systems (DCS) of Bakersfield, CA, became interested in pursuing IDP as a business line for the geothermal drilling industry. They built three joints of prototype IDP, did preliminary tests to evaluate the effective thermal conductivity of the pipe, and ran these joints in field operations – drilling one geothermal well and working-over another. This effort led to further analysis, fabrication, and testing of IDP, including the construction of a complete string of large-diameter IDP used in a field test in an Imperial Valley geothermal well in 1999.

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[1] J. T. Finger, "Drilling Fluid Temperatures in a Magma-Penetrating Wellbore," *Geothermal Resources Council, TRANSACTIONS, Vol. 10,* September 1986

This field test demonstrated not only that IDP delivered the thermal advantages predicted by analysis, but also that we could reliably model its performance[2]. The 5" IDP developed for the geothermal industry, however, was much too large and heavy (>50% increase over 5" CDP) for a typical deep HTHP gas well below 15,000 feet.

The design concept used for insulated drill pipe in this project is shown in Figure 2. Construction is based on conventional drill pipe, with the tool joints modified to accept a liner tube (described in detail in Section 3), and with the annulus between the pipe body and liner filled with insulation. This assembly is simple and rugged, with virtually no effect on the strength of the parent drill pipe. The insulating material is a proprietary, but commercially available, compound.

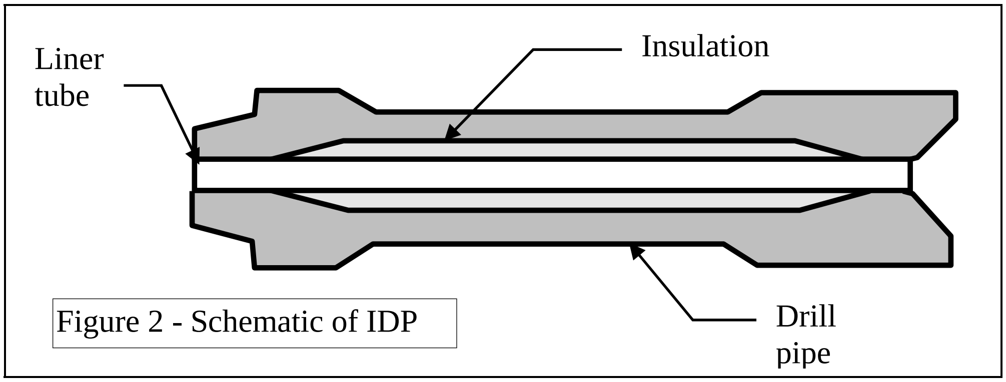

Figure 2 - Schematic of IDP

To discuss the performance of IDP built to this design, we will return to Figure 1, shown in the Executive Summary. These curves are calculations, not field data but, as stated earlier, the thermal properties of the IDP are measured quantities; the drilling, wellbore, and formation parameters are taken from an actual well in South Texas; and the calculation method is one that has proven realistic in field experiments in a geothermal well.

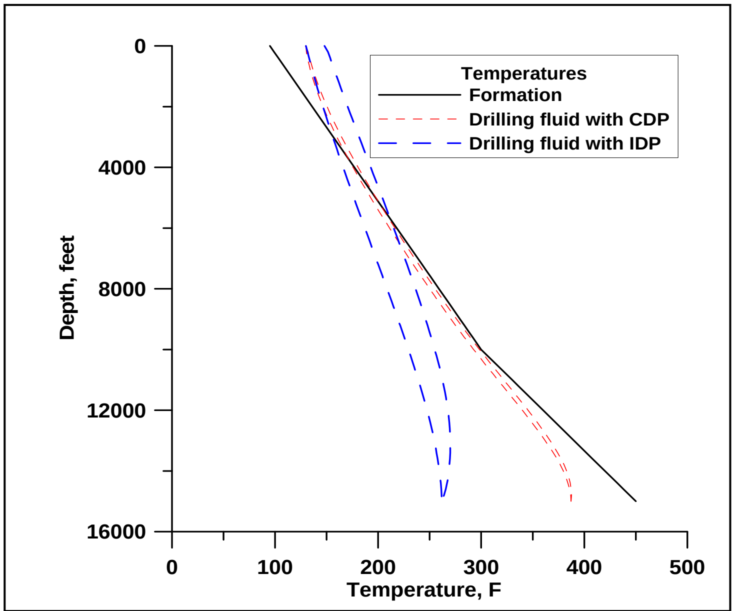

Figure 1 – drilling fluid temperatures with IDP and CDP

Several important aspects of IDP performance are shown in the figure.

- Bottom-hole circulating temperature is reduced from 387ºF with CDP to 252ºF with IDP. This is the temperature that downhole motors, steering tools, or measurement-while-drilling (MWD) instrumentation must survive. A temperature

[2] J. T. Finger, R. D. Jacobson, A. T. Champness, "Development and Testing of Insulated Drillpipe", SPE 59144, presented at the 2000 IADC/SPE Drilling Conference, New Orleans, LA, February 2000

reduction in this temperature range is especially valuable because many tools have a performance limit at about 310-325°F. It is important to note that the bottom-hole cannot be effectively cooled by simply lowering the mud inflow temperature. In the situation illustrated by Figure 1, for example, using coolers to lower the inflow temperature by 40°F while using CDP lowers the bottom-hole temperature by less than 2°F.

- Maximum fluid temperatures, which are not at the bottom of the hole, are 388°F for CDP and 270°F for IDP. For drilling fluid additives that degrade at high temperature, this difference can be critical.
- Fluid return temperatures are 130°F for CDP and 148°F for IDP (with inflow temperatures of 130°F.) This indicates that more heat is being removed from the wellbore, and therefore formation temperatures will be lower after drilling with IDP.
- The equivalent circulating density (ECD) is very important in calculating pressure drops in deep wells, and ECD is highly temperature-dependent. Because the curve of annulus temperature is more nearly vertical with IDP, this means the ECD will be more constant, and therefore more predictable, with IDP.
- The wellbore temperature profile can be controlled at some level between the curves defined by the "full IDP" and "full CDP" cases by tailoring the drillstring with a mixture of the two kinds of pipe.
- A little bit of insulation makes a profound difference. It is shown in detail elsewhere[3] that the un-insulated tool joints and a variation in insulation conductivity by a factor of five have relatively small effects on the thermal performance.

With this basic understanding, then, the balance of the report is devoted to activities pursued under this Award.

[3] J. Finger, R. Jacobson, G. Whitlow, T. Champness; "Insulated Drill Pipe for High-Temperature Drilling", *Sandia Report SAND2000-1679*, Sandia National Laboratories, July 2000

3. PRELIMINARY DESIGN

3.1 Method/Approach

The preliminary design presented to DOE/NETL was based on an existing string of 3.5" drill pipe built by Drill Cool Systems. The design follows the general concept shown in Figure 2 (p. 4) but is augmented by details of materials and construction methods. Given that concept, there are several decisions to be made: what kind of insulation should be used; how should it be applied/attached to the drill pipe; how much protection does it need; and what should be the overall configuration of the assembled pipe? Many of these decisions, however, are greatly simplified by the fundamental principle that a relatively small amount of insulation has a major impact on drilling temperatures. With that in mind, we can examine several design features in more detail.

<u>Insulation quality</u>: In the equation for heat transfer through a unit length of the insulated portion of the pipe, five quantities make up the thermal resistance through the pipe wall: convective heat transfer coefficients at the outside and inside surfaces, and conductivities of the drill pipe, the liner tube, and the insulation. For conditions typical of drilling, four of the five quantities are numerically of similar magnitude. Only the quantity that represents the low-conductivity insulation is much smaller than the others. For conventional steel pipe (CDP), then, the convective and conductive terms are relatively equal in importance, while the insulation dominates the total heat transfer for insulated pipe. This means that even a small amount of insulation has a significant effect on heat transfer; in other words, the insulation doesn't have to be extremely efficient.

Another limit on minimum heat transfer is set by the un-insulated tool joints at each end of each piece of pipe, which would conduct heat even if insulation in the pipe body were perfect. In considering possible insulation materials, there are many kinds of plastic, glass, or rock that have conductivity, or *k*, values from 0.1 to 0.5 B/hr-ft-F, compared to steel at 26 or good insulators such as cork at 0.025 or glass wool at 0.022 B/hr-ft-F, so a key question is to determine what range of *k* value is necessary. In evaluating insulation requirements, however, calculated drilling fluid temperatures (including the effect of the tool joints) show that there is little difference in performance among IDP designs with an insulating layer having conductivity values of 0.05, 0.3, and 1.0 B/hr-ft-F.

<u>Tool joints</u>: Using the same rationale as above, there is little advantage to insulating the tool joint area, since this only represents about 10% of the total length of the drill string (and the tool joints' wall thicknesses are already much greater than the pipe body, which reduces heat transfer through them.) Insulating the tool joints is also a difficult technical challenge, which would adversely affect cost, complexity, and reliability.

<u>Insulation protection</u>: Given that the insulating layer is contained between inner and outer metal tubes, there is a question as to how much protection it needs. Early in the IDP evolution, the inner tube was designed to be strong enough to withstand internal pressure on its own, but with the use of an insulating material having enough compressive strength to support the liner tube against internal pressure in the pipe, the liner tube can be of much less robust construction.

Pipe strength: Because of the design approach discussed above, strength of the IDP is taken to be the strength of the parent drill pipe. This pipe is first modified by attaching the liner tube and by drilling a hole in the flank of the tool joint to fill the annular cavity with the insulation material. The liner tube and the insulating material are thus assumed to neither detract from nor add to the strength of the original pipe insofar as pressure capability is concerned. Because the IDP is somewhat heavier than equivalent CDP (16.4 lb/ft versus 14.2 lb/ft for the preliminary 3.5" design) there may be an issue with tensile strength for very long drill strings.

3.2 Results

The design principles above led to the preliminary design shown in diagram below (Figure 3).

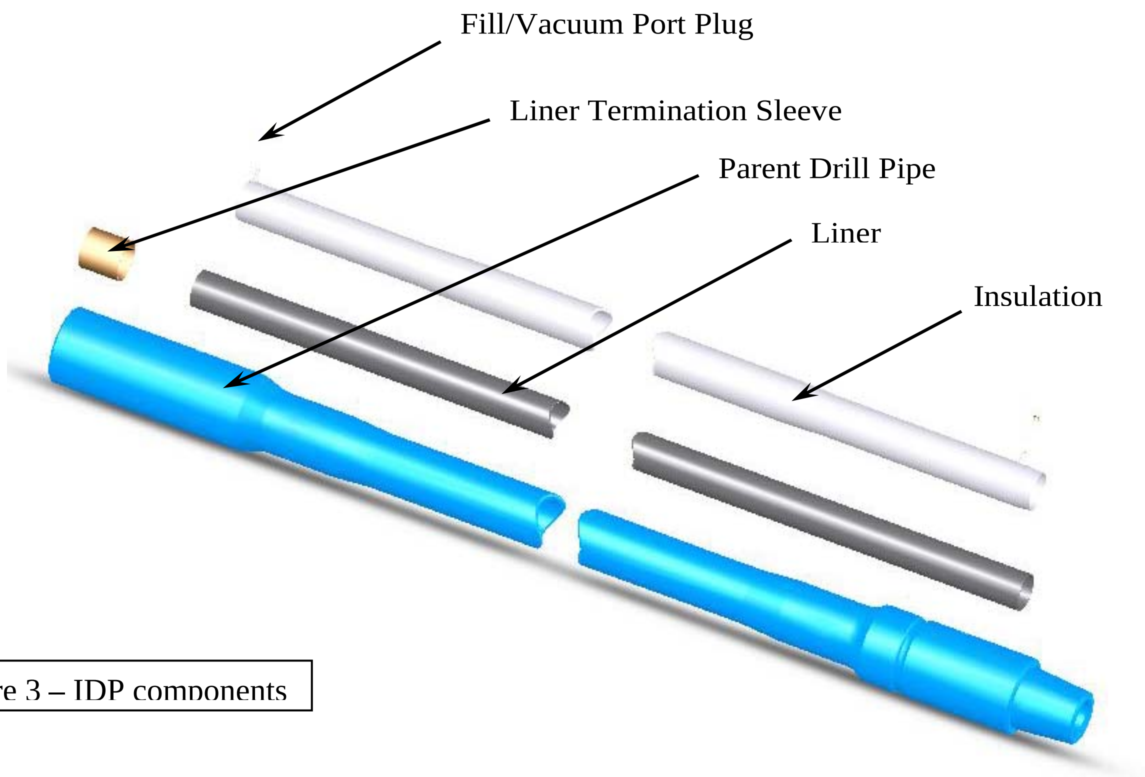

Figure 3 – IDP components

Table 1 gives relevant dimensions for the IDP components.

Conventional Drill Pipe Description	3-1/2"	13.3#	NC38
Conventional Drill Pipe Tool Joint ID (in)		**2.125**	
Conventional Drill Pipe Nominal ID (in)		**2.764**	
Insulation Thickness (in)		0.195	
Liner ID - IDP Adjusted ID (in)		**2.245**	
IDP Adjusted Weight per Foot (lbs/ft)		16.426	

In general, the parent drill pipe is modified to accept the liner in the following way:

1. The inside diameter of the box end tool joint is bored slightly larger than the outside diameter of the liner.

2. The pin end tool joint is bored to form a register, or “stop” for the end of the liner, which is inserted from the box end. (Figure 4)
3. Both tool joints receive a threaded hole, used for filling the annulus with insulation.
4. The liner is inserted into the drill pipe, marked for the correct length, then withdrawn and cut to length.
5. Liner is re-inserted into the drill pipe and the brass Liner Termination Sleeve is fixed in place in the box end tool joint to retain the liner.
6. The insulation and its curing agent are mixed and de-aerated, then injected into the annulus between the liner and drill pipe. Insulation is injected into one fill hole while vacuum is drawn on the other.
7. After the insulation is cured, the fill plugs are screwed into the fill holes and secured with thread-lock compound.

Note: The composition of the insulation material, and details of the installation procedure for the Liner Termination Sleeve, are proprietary to Drill Cool Systems, but the complete process has been described in a separate Topical Report submitted to DOE/NETL.

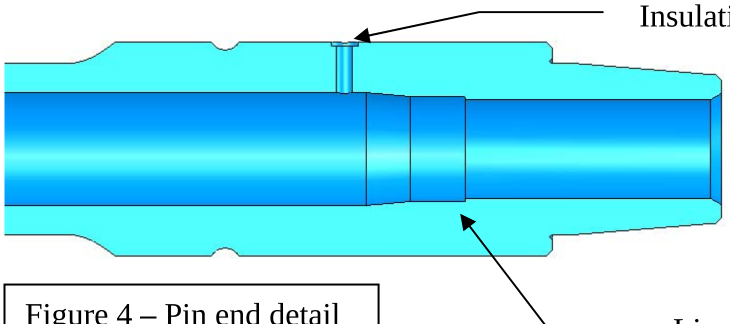

Figure 4 – Pin end detail

3.3 Conclusions

Insulated pipe can be used in any HTHP environment serviced by conventional drill pipe. None of IDP’s components are susceptible to high temperature and its performance does not change with temperature. The parent drill pipe can be any grade, in case there is a need for corrosion resistance or other unique properties.

A possible limitation on IDP use is its inside diameter, which is smaller than equivalent conventional pipe because of the liner tube. This means that, for a given flow rate, there will be greater pressure drop through a string of IDP than through an equivalent string of conventional pipe. This factor turned out to be one of industry’s principal concerns.

4. MECHANICAL TESTING

4.1 Method/Approach

The general approach to mechanical testing was to identify the operating environment that the pipe sees in HTHP use and to analyze the stresses that result from that situation. The test plan, which attempted to reproduce those stresses and to evaluate their effect, was developed with Stress Engineering Services (SES) in Houston, and the Scope of Work for the SES contract is given in Appendix A. An outline of the test plan, with a brief rationale for each test, is given below.

1. *Tensile*: The principal concern in tension is that the pipe body is made from stronger steel than the liner. This means that when the assembled pipe is stretched, the liner may yield while the pipe body is still in the elastic range. When the tensile load is relaxed then, the liner will be in compression and might experience slight buckling. In the tensile test, the pipe will be loaded to 90% of the pipe body yield, with simultaneous internal pressure, and will be cycled through this loading several times. The complete inside diameter surface of the pipe will be inspected before and after the test with a “borescope” that can optically identify any distortion. As the final step in the testing, the pipe will be pulled until the pipe body yields.

2. *Internal pressure*: Internal pressure capacity of the IDP should actually be greater than for the parent drill pipe, but the contribution of the liner and insulation will be ignored. The concern is that somehow a flow path might be established through the fill plugs used to inject the insulation into the annulus between the drill pipe body and the liner. The IDP will be pressurized to 7500 psi and the fill plugs will be monitored for leaks while this pressure is held. Fill plugs will also be monitored during the tensile test, when the pipe will be internally pressurized.

3. *Fatigue*: Most drill pipe failures are related in some way to fatigue loading, and most of these failures occur near the point where the drillpipe and tool joint are joined. This is particularly relevant for IDP because of the tool joint modifications required to seat the insulation liner. Although the drill pipe manufacturer has done finite-element analysis of this modification and found it to be inconsequential, we felt that it is important to confirm this with fatigue testing.

   Stress levels for the fatigue test will reproduce stresses developed in drilling a deviated well with a build rate of 15^{O}/100 feet. Pipe configuration for the test, to focus on the tool joint area, will be an assembly in which a joint of IDP will be cut in two at the middle and the two ends screwed together. A rotating eccentric weight applied to the end of the pipe will then load the pipe in a fatigue mode until it fails. Pipe condition will be monitored by internal water pressure, with a wet-detector near the tool joint to signal when there is a leak. The pipe will be tested to failure in this fatigue mode, and the results will be compared with other proprietary fatigue data at Stress Engineering. This will enable us to make sure that the IDP fatigue performance lies roughly on the same fatigue curves as conventional drill pipe.

4. *Torsion*: Torsion load on the drill pipe will be 20,000 ft-lb, which represents 60% of the torsional yield strength of the pipe. It is also well above the recommended make-up torque (11,000 ft-lb) for the connection. The pipe will be cycled through this loading five times and will be monitored for leakage.

5. *Compression*: This test will address any concern that the liner would deform under compressive loads on the drill string. Normally, the bottom-hole assembly is designed so that drill collar weight will keep the drill string in tension, but as deviated wells become common, there is some occasion for drill pipe in compression. The test will load the pipe to 50% of compressive yield.

4.2 Results

Testing was done at SES facilities in Houston. Most of the testing was done during July, 2007. A brief recap of each test procedure and its results is given below, and the complete SES test report is in Appendix B.

Internal pressure test: Applied 2500 psi internal pressure to pipe. No leakage into insulated annulus.

Tensile to proof load: Applied axial tensile load of 343,650 lbs (90% of premium class strength). Leakage from pipe ID into annulus between internal tube and drill pipe body was measured by removing the insulation fill plug and testing for leaks. Leakage occurred at 800 psi, but it should be emphasized that this is only an indication of a leak at the point where the liner tube is seated into the tool joint. This is a minimal effect because it would only introduce a small amount of drilling fluid into the insulation volume, which would have a negligible effect on the insulating properties of the IDP. Because the fill plug is very sturdy, it is extremely unlikely that the fluid path could pass through it and lead to a washout.

Tensile to yield: Applied axial tensile load of 492 kips. No apparent yielding of pipe body. No visual buckling or damage to internal tube.

Compression to yield: Applied compressive load of 235 kips. Pipe buckled.

Fatigue Test: Induced cyclic outer fiber strain of 600 microstrain (18,000 psi) in pipe adjacent to external upset. Pipe ran for 1,362,900 cycles. No leakage at 200 psi into insulated annulus after test. Fatigue test set-up is shown in Figure 5.

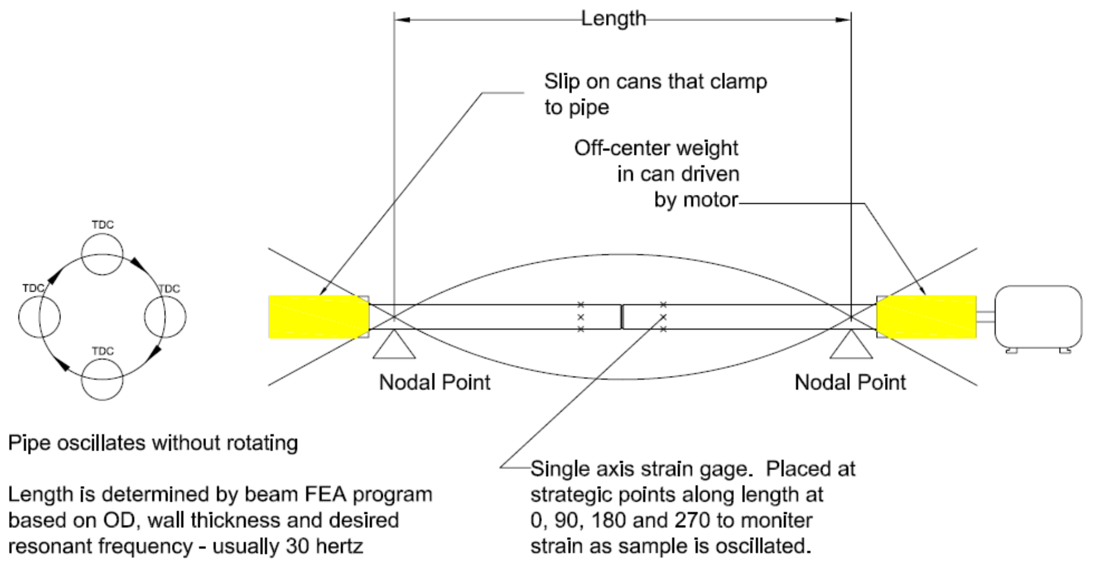

Figure 5 – Schematic of fatigue test set-up

These fatigue test results showed that the IDP fell along a line for steel pipe in general (Figure 6), which is a desired outcome because it indicates that the mechanical modifications to the pipe required by the addition of insulation do not degrade the fatigue strength of the parent pipe body.

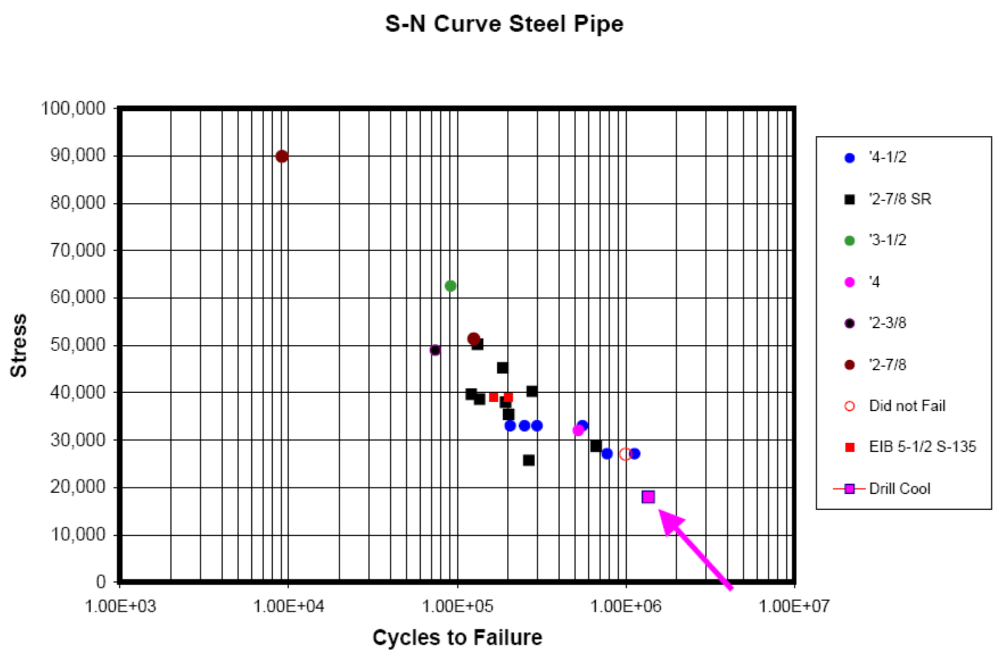

Figure 6 – Fatigue life for IDP sample

Torsion to yield: Pipe loaded in torsion to more than 33,000 ft-lbs (above yield strength), which produced a twist angle of 77^{O}. No leakage from pipe bore into insulation annulus after test.

4.3 Conclusions

The test program, which we consider to be successful, is summarized in Table 1 below. The mechanical test program did not reveal any fundamental flaws in the preliminary design.

Table 2 – Mechanical Testing		
Test Activity	**Rationale**	**Results**
Internal pressure	Monitor fill-plug performance	IDP pressurized to 2500 psi. No leakage into insulated annulus.
Tensile, proof load	Evaluate liner movement	Pipe loaded to 344 k-lbs (90% premium strength). Small leakage into insulated annulus, but this is not critical to either strength or insulation properties.
Tensile to yield	Pipe failure or liner buckling	Pipe loaded to 492 k-lbs. No parting of pipe body, no visible buckling of liner.
Compression to yield	Evaluate effect on liner	Pipe loaded to 235 k-lbs (above 50% yield), with anti-buckling supports. No noticeable effect on liner. Drilling plans always strive to keep drill pipe in tension, but occasionally deviated wells will apply compression.
Fatigue	Effect of liner installation	Induced cyclic strain of 600 µin/in (18,000 psi stress). Pipe ran for 1,362,900 cycles with no leakage at 200 psi into insulation annulus. This result fell along the curve for steel pipe in general, which indicates that the liner modifications did not degrade the fatigue strength of the IDP.
Torsion to yield	Effect of torsion on liner	Pipe loaded in torsion to more than 33,000 ft-lbs (above yield strength), which produced a twist angle of 77^{O}. No leakage from pipe bore into insulation annulus after test.

Perhaps the most important part of the mechanical testing dealt with fatigue, because there had been some industry feedback that machining the tool joints to accept the ends of the insulation liner tube might create a stress riser. Although analysis had indicated that this effect is negligible, it was important to be able to show this in physical testing.

5. INSPECTION PLAN

5.1 Method/Approach

Much of conventional drill pipe inspection relies on visual access to the pipe surface, or on NDT techniques (ultrasonic, etc.) that can look "through" the pipe from the outside to detect flaws on the inside surface. Once conventional drill pipe is converted into IDP by installation of the liner and insulation, then visual access is no longer possible, and the inside diameter is no longer a free surface. It is important to verify that NDT techniques can still detect flaws inside the drill pipe body (i.e., in the annular space beneath the insulation and liner). To provide quality assurance for the assembled IDP, Drill Cool Systems contracted with TH Hill Associates in Houston to develop an inspection plan for the assembly. (See Appendix C for Scope of Work for the TH Hill contract and Appendix D for details of the inspection procedure.)

5.2 Results

The essence of the inspection plan was to compare four conventional NDT methods and their abilities to detect flaws on the inner surface of the parent drill pipe after assembly of the IDP components. The planned mechanism for this comparison was to deliberately machine flaws into a virgin pipe body, inspect this pipe with various methods to evaluate their accuracy, install the liner and insulation, and re-inspect the assembled IDP to verify that the chosen method(s) could still identify the flaws.

The essential nature of this activity is to machine "standard" flaws into premium drill pipe before the insulation is installed, and then develop an inspection protocol using the standardized method that best captures the nature of the flaws with insulation in place. (See Appendix C for details) This plan is a modification of the industry-standard DS-1 inspection, so it should be widely acceptable even to people who are not familiar with the IDP concept. The inspection methods considered in development of the plan are the following:

- Full Length Ultrasonic Testing (FLUT)
- Ultrasonic Wall Thickness Inspection
- Ultrasonic Slip/Upset Inspection
- Electromagnetic Inspection (EMI)

Three pipe sizes were chosen for use in this development: 3-1/2", 5", and 6-5/8", and in each case, the heaviest available wall thickness was acquired to evaluate how deeply into the material the relevant NDT method could penetrate. Pipe sizes reflected our best estimates of what the potential markets for IDP might be: 3-1/2" is typical for South Texas and other onshore drilling; 6-5/8" is commonly used offshore; and 5" is a generic, and common, pipe size for other applications. The pipes' specific weights, tool joint sizes, conditions, and diameters were the following (the variation in condition-new to used-would also help evaluate the effect of wear on the inspection procedure):

- 3-½ ", 13.30 lb/ft, NC38 connection (used)
- 5", 19.50 lb/ft, NC50 connection (new)
- 6-5/8", 27.70 lb/ft, 6-5/8FH connection (premium)

A secondary objective of the inspection development was to determine whether the inspection procedure can measure the concentricity of the pipe and liner (how well the liner is centered in the pipe) and evaluate the insulation fill (whether there are voids in the insulation). This function is less important structurally than flaw detection, but would be a useful addition to the IDP quality control.

There were four basic steps for completion of the inspection plan:

1. Three sizes of drill pipe to be bored out and machined to accept liners so they could be converted into IDP.
2. The modified DP to go to an inspection facility where the artificial flaws would be machined into the pipe, and the pipe then be inspected by four NDT methods to assure that these methods can detect the flaws.
3. The modified pipe, with flaws, to be shipped to Bakersfield where Drill Cool would install liners and insulation, and then be returned to Houston.
4. The assembled IDP with flaws would be inspected by the same four methods as before and the methods will be evaluated to choose the most effective one(s).

This component of the project was plagued by several factors related to the extremely high level of activity in the drilling industry. First, acquisition of the required drill pipe was very difficult: manufacturers were not interested in small orders for new pipe, and available inventories were committed to other buyers. Second, machine shops with the equipment and qualifications to work on oil-field equipment were booked up months in advance. Finally, even the inspection facility was overloaded with work, although it was not as severe a delay as in the other steps. The total delay caused by these considerations, relative to what could have been accomplished with prompt access to materials and services, was roughly one year.

After these delays, this activity reached a point at which the pipe was in hand, the artificial flaws were machined into it, and baseline inspection with the various techniques was performed.

5.3 Conclusions

During the long hiatus described above, however, a new consensus began to emerge about the optimum design for insulated drill pipe. Driven in large measure by the market surveys and industry interaction, Drill Cool moved toward an IDP concept based on application of an insulating coating to the outside diameter of the parent drill pipe, with no separate liner or other metal jacket to protect the insulation. This idea is discussed in more detail in Sections 6 and 7, but the basic notion was that, if IDP with double-wall construction was not marketable, then further work on development of an inspection plan was not worthwhile.

6. MARKET SURVEYS

6.1 Method/Approach

The projected Phase 2 of this project included tasks of building 12-15 pieces of prototype IDP and then running these in an actual HTHP well. The market surveys, then, had two major objectives—determine what size pipe would most likely be acceptable to an operator with a potential drilling opportunity, and identify any concerns that operators, drilling contractors, or service companies might have that would bias them against using IDP. To gather this information, Drill Cool contracted with Spears and Associates, a market research firm in Tulsa, OK, that has extensive experience in the oil and gas industry (Scope of Work for Spears and Associates is given in Appendix E). Drill Cool representatives also attended the World Oil HTHP trade show in Houston, both in 2007 and 2008, where other attendees filled out questionnaires related to possible IDP use, and returned them to Drill Cool.

6.2 Results

Spears and Associates contacted more than 100 operators and service companies in an attempt to answer some of the basic questions given previously (What is the market for IDP? What are the barriers to industry acceptance? And, perhaps most critical, what is the optimum IDP size to meet most industry needs?) Unfortunately, because of the extreme press of business in the oil industry, they received a limited response. Operators were about evenly divided on whether they considered IDP to be worth further investigation, but the responses made clear the fact that many of them didn't really understand the concept. Unfortunately, the interviewers themselves were not knowledgeable enough about IDP to provide answers to some of the operators' concerns (e.g., several interviewees were concerned about getting fishing/logging tools through the reduced inside diameter, but the interviewers were not familiar enough with IDP to point out that the drill pipe ID is no smaller than the ID of the tool joints). Service companies (directional drilling) were much more enthusiastic about the IDP concept, with six out of seven interviewees expressing definite and favorable interest in the technology.

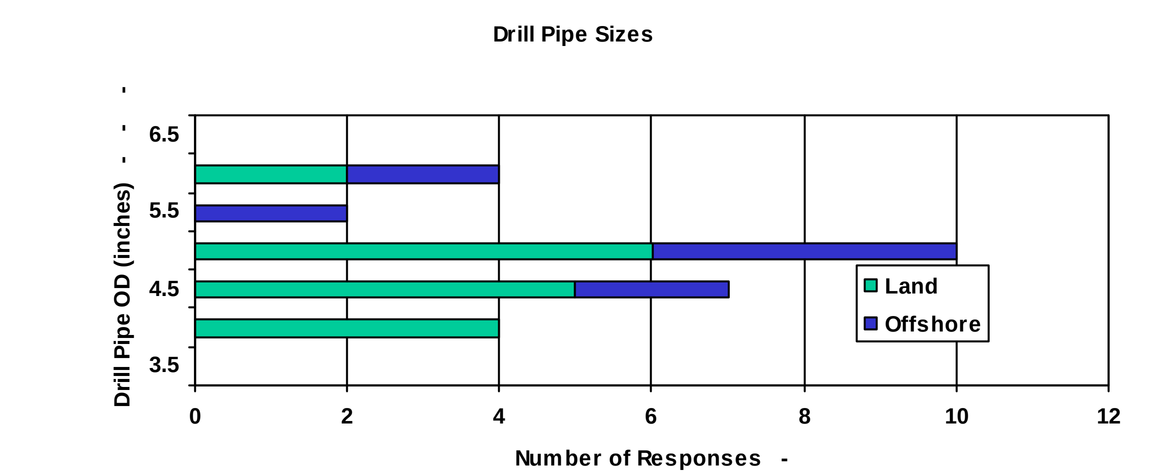

Figure 7 – Desired pipe sizes from market survey

On the subject of pipe size, the relatively small sample size did not lend confidence to a choice of optimum diameter for a string of IDP to meet industry needs. For example, responses to the market survey are shown in Figure 7.

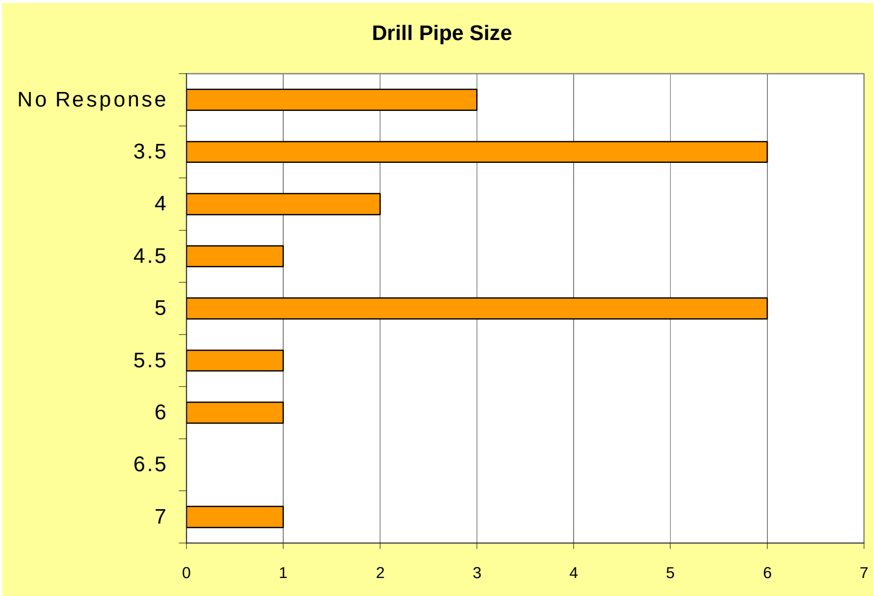

Figure 8 – Desired pipe sizes from trade show survey

In comparison, Drill Cool passed out questionnaires at the HTHP trade show in April 2007, and the results of those surveys is shown in Figure 8.

Although some trends are apparent, the small sample size does not give sufficient confidence to identify the optimum pipe size. As a generality, almost all interviewees were strongly in favor of the largest possible inside diameter, to address both hydraulics and fishing tool issues.

In an attempt to improve this result, Drill Cool requested additional survey activity from Spears and Associates, and once again had representatives passing out questionnaires at the 2008 HTHP Trade Show and Conference in Houston. Although some additional data were acquired, and we can make the general statement that off-shore operators favor larger pipe (~ 6-5/8") and on-shore operators prefer smaller (~ 4") sizes, there was no clear answer to the question of optimum pipe size. Because Drill Cool could not afford to make more than one size prototype pipe, it was critical to choose a size that had some assurance of use in the market.

6.3 Conclusions

In the course of these conversations about pipe size, however, another issue arose that turned out to be more important to the project's progress, and that was the matter of pipe hydraulics. The quandary was this: although the market survey did not provide enough information to specify an optimum size, both on- and off-shore potential users remained concerned about pipe hydraulics. With the inherent configuration of the existing IDP design, there will always be a conflict because a pipe OD chosen for maximum strength in a given hole will always have a smaller ID with insulated drill pipe, thus increasing the circulating pressure drop compared to conventional pipe. This conflict appeared to be intractable with the operators interviewed, although it's very possible that they rejected the proposed sizes without sufficient knowledge or consideration.

For example, in considering pressure drop, it is well known that pressure losses are very sensitive to pipe diameter, but it may not be clear that having a relatively constant inside diameter with IDP offsets some of the effect of diameter change at the tool joints in conventional pipe. In a field test in 1999, pressures during circulation were measured at top and bottom of strings (~ 4000' each) of 5" IDP and 4-1/2" CDP with inside pipe body diameters of 3.068" and 3.826", respectively. In the conventional pipe, tool joint diameters were 2.812", and this represented about 10% of the pipe length. At 500 gpm circulation rate, pressure drops in the IDP and CDP were 0.204 psi/ft and 0.156 psi/ft, respectively. If we consider just the inside diameters of the pipes, however, and use the mathematical relation that pressure drop varies inversely as the fifth power of the diameter, the calculated result is that the IDP would be expected to have more than twice the pressure drop of the CDP, but the data show that the IDP pressure drop is actually only about 30% higher. The tool-joint diameter reduction apparently has a substantial effect on pressure drop in the 4-1/2" drill pipe.

This is just one example of possible misperception or lack of information, but whatever the case, we seem to face, late in the game, a scenario in which the current IDP concept appears to be unmarketable. This situation is discussed in more detail in Section 7.

7. CONCLUSIONS

Bringing new technology to market requires at least two major accomplishments—the new hardware or technique must satisfy the technical requirements it is designed to meet, and the target industry must recognize or be persuaded that this technology is an appropriate answer to their needs. The authors of this report will argue that we succeeded in the first part, but failed in the second.

The insulated drill pipe design described in Section 3 is proven, in that it has been used in the field, mechanical testing showed no flaws, and very similar pipe has demonstrated the desired and expected thermal performance in a carefully controlled field test. At the very minimum, we can claim that there is no evidence showing the existing IDP *doesn't* perform as desired. All this is virtually irrelevant, of course, if the industry does not accept IDP as a legitimate answer to the needs of HTHP drilling.

New technology will face resistance in almost anywhere, and the oil and gas industry has two particular challenges: innate conservatism in drilling practices, and the "boom/bust" business cycle that seems prevalent for much of recent history. Given the very expensive nature of new drilling projects, it is quite reasonable that drilling engineers or contractors would be reluctant to use any new piece of equipment that might pose a risk to the well, without having some firm basis for believing either that the risk is negligible or that the performance benefits justify some small amount of risk. Either of these reassurances, however, will almost certainly require some kind of field test or drilling exercise, which is why it's so important for DOE or other Federal agency to take the lead in providing this sort of demonstration.

Even with performance verification, the question of timing remains. If drilling is in "boom" times, activity is high, and riskier (often, higher temperature) wells are being drilled. Contractors and service companies are stretched to the limit just to keep up with ordinary demand, and they have little time or incentive to investigate a new technology. This is more or less confirmed by the fact that, in the market survey, service companies were far more enthusiastic than operators about IDP—directional drilling service companies see a direct benefit in mitigating the high-temperature risk to their delicate and expensive equipment, while operators view this situation as the risk being borne by someone else. In the market survey, in fact, there were several direct quotes from operators to the effect that, "We don't have any high-temperature problems," whereas the service companies had a much different view. It is worth noting that the president of Drill Cool has recently talked with three different Gulf Coast operators who have severe problems with bottom-hole circulating temperatures above 300^{O}F—in one case, the operator has suffered loss above $1M from high-temperature tool failure.

With drilling in a "bust" cycle, by contrast, wells are not as challenging (usually, lower temperatures) and the drilling industry is under financial pressure that precludes investment of time and/or money in new technology if the existing equipment can do the job in any fashion.

In summary, then, the marketing problems fell into two general areas: some operators and drilling contractors didn't feel that they needed the capability of managing downhole temperature; and, among those who did, there was concern over the reduction in inside diameter.

As a result, we found ourselves, very late in the game, facing a basic paradigm shift in which the IDP design would become drill pipe with either a coating on the ID to reduce friction with the existing double-wall design, or a single-wall design with an insulating coating on the OD of the pipe body between the tool joints. There was not enough time or budget to investigate these approaches in the present project, so we ended this project having done the work described in this report. Drill Cool will most likely pursue the revised design concepts independent of NETL funding, but it is uncertain when this might happen.

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LIST OF ACRONYMS AND ABBREVIATIONS

BHA – bottom-hole assembly; essentially the components between the lower end of the drill pipe and the bit
CDP – conventional drill pipe
DCS – Drill Cool Systems, Inc.
ECD – equivalent circulating density (the effective density of the drilling fluid, after adjusting for temperature, fluid friction, and viscosity effects)
HTHP – high-temperature, high-pressure; definition of these conditions is not uniform, but for this report it will mean temperatures above 400^{O}F and pressures above 15,000 psi
IDP – insulated drill pipe
LWD – logging while drilling (usually implies gathering formation data)
MWD – measurement while drilling (usually related to drilling parameters)
NDT – non-destructive testing
SES – Stress Engineering Services, a Houston company that helped design and then perform mechanical testing

APPENDIX A – MECHANICAL TESTING PROCEDURE

Test Procedure: 3-1/2” Double wall insulated drill pipe.
Client: Drill Cool Systems, Inc.
Objective: To conduct tension, compression, internal pressure, torsion and elevated temperature tests on 3-1/2” pipe with NC38 (3-1/2 IF) tool joints.
Pass/fail criteria: Does annular space hold pressure?
Record data at 1 scan/sec

1. Set-up frame. Pipe is approximately 32 ft long. Adaptor subs are at Stress Engineering.
2. Put 1-3/4” filler bar in pipe.
3. Buck on adaptor subs – 10,000 ft-lbs. Use o-rings on subs. Use copper base thread compound.
4. Pipe has a port on each tool joint that will be used to detect leaking through inner pipe seals. Inner pipe seals against tool joint ID on each end.
5. Apply tensile load of 343,650 lbs (90% of premium class strength). Hold 15 minutes. Release load. Record applied load and axial stretch between drill pipe external upsets.
6. Apply pressure of 2500 psi gas to pipe ID. Hold 15 minutes. Record pressure. Watch ports in tool joints for leakage. Release pressure. ID volume with filler bar – 600 in^3.
7. Apply torsional load of 25,850 ft-lbs.
    a. Use chain tongs and load cell.
    b. Hold 15 minutes
    c. Release torque
8. Repeat step 5.
9. Heat each end of pipe to 300 F.
    a. Use induction heat
    b. Hold 15 minutes after temperature stabilizes
    c. Remove heat source.
10. Repeat step 5 before pipe cools off.
11. Repeat step 5 after pipe cools off.
12. Weld anti-buckling rings to frame.
13. Apply compressive load of 343,650 lbs. Hold 15 minutes. Record load and axial compression between drill pipe upsets. Release load.
14. Repeat step 5
15. Apply 7500 psi water pressure to pipe ID. Hold 15 minutes. Record pressure.
16. Release pressure
17. Apply axial tensile load to yield – Approximately 380,000 lbs. Release
18. Repeat step 5. Record applied load and axial stretch between drill pipe external upsets.

APPENDIX B – MECHANICAL TESTING RESULTS

Certificate of Test

Stress Engineering Services, Inc.

13800 Westfair East Drive

Houston, Texas 77041

Date:	September 28,2007	PN115443
Client:	Drill Cool	
Test Pieces:	3-1/2" 13.30 ppf S-135 Previously Used Insulated Drill Pipe Assemblies. The drill pipe had NC38 tool joints and was 31-1/2 ft long from make-up shoulder to make-up shoulder.	
Test Requirements:	1. Determine if leakage occurred at interface of inner tube on each end of pipe after subjecting pipe to tension, torsion and compression. 2. Determine fatigue characteristics of drill pipe assemblies.	

Tension Test

Prior to conducting the tension test, 2528 psi internal pressure only was applied to verify that there was no leakage at the ends of the inner tube.

A tensile load of 347,268 lbs (90% of the tensile strength of premium class pipe) was applied to the pipe and held for 15 minutes. Pass/fail criteria was leaking from pipe ID into annulus between internal tube and drill pipe body

Internal pressure only was applied and leakage occurred at 800 psi at the interface of the inner tube and tool joint on the box end.

Compression Test

A compressive load of 234,519 lbs was applied to a second piece of pipe at which time buckling occurred. The calculated compressive strength of the pipe with no buckling is 488,825 lbs. The pipe was laterally supported at 7.33 foot intervals to increase the buckling load. The calculated buckling load of each end of the pipe was 377,221 lbs. The calculated buckling strength of the two center sections was 737,634 lbs. Calculations are in Appendix H.

Tony Worthen chose not to conduct the internal pressure test on this test.

Fatigue Test

A single joint of pipe was cut in two at approximately mid length and the pin and box were bucked-up to each other. End caps were welded to each end of the test piece so that the pipe ID could be pressurized – a drop in pressure during the test would indicate a through wall crack. The pipe ran for 1,362,900 cycles before a crack formed in the pipe body two feet from the make-up shoulder on the pin end. The pipe had a cyclic outer fiber stress of 18,000 psi adjacent to the external upset.

The end caps had a pressure rating of 200 psi. There was no leakage at 200 psi into the insulated annulus after test..

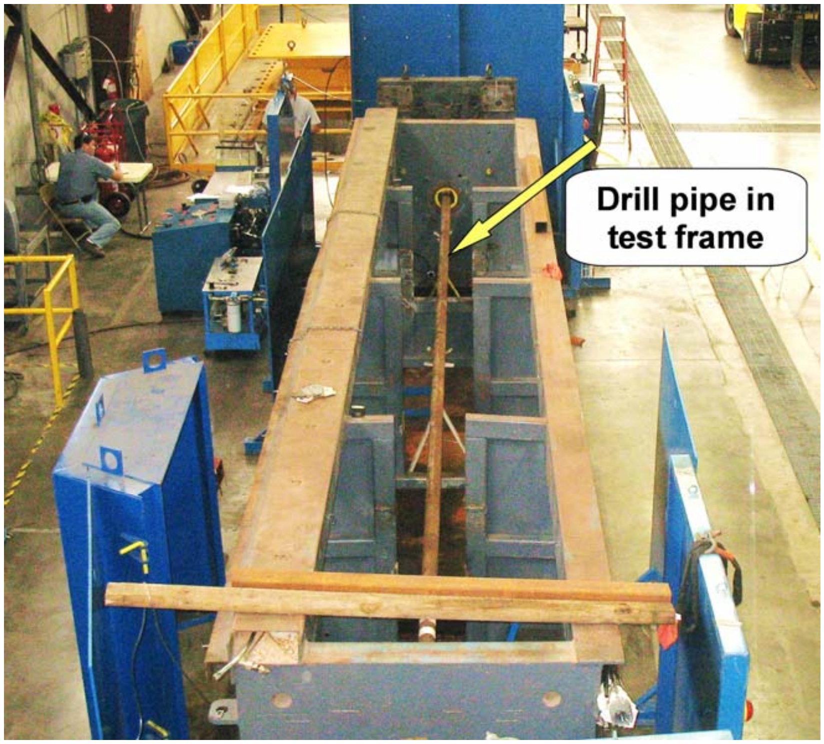
Torsion test

Pipe was subjected to torsional deflection of greater than 77 deg. Seventy seven degrees is the angle of twist at a torque of 33,413 ft-lbs which is the torsional yield of this pipe. An internal pressure of 2500 psi was applied to the pipe after the test. The pressure held for 15 minutes. There is no computer record of the pressure test.

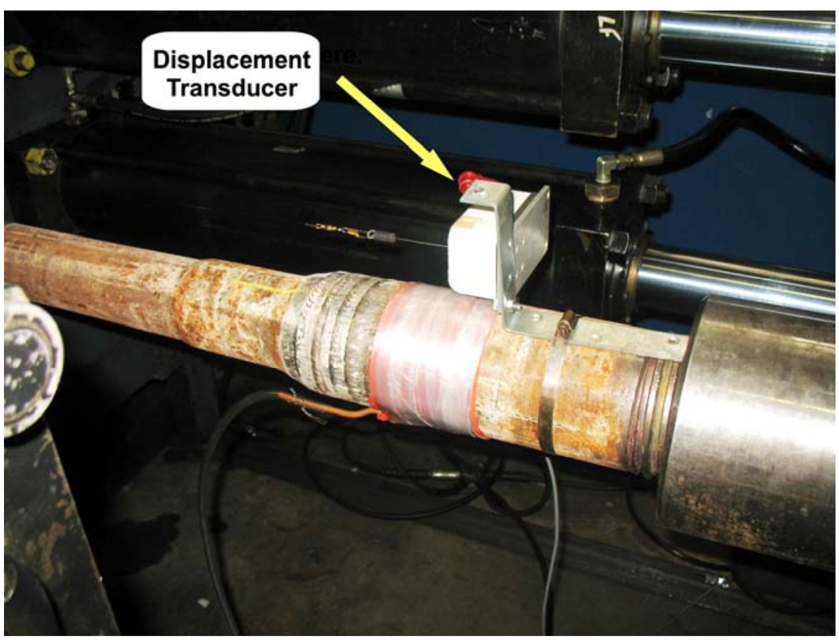
Table of Contents

Jackie E. Smith PE
Staff Consultant

Appendix A
Photographs

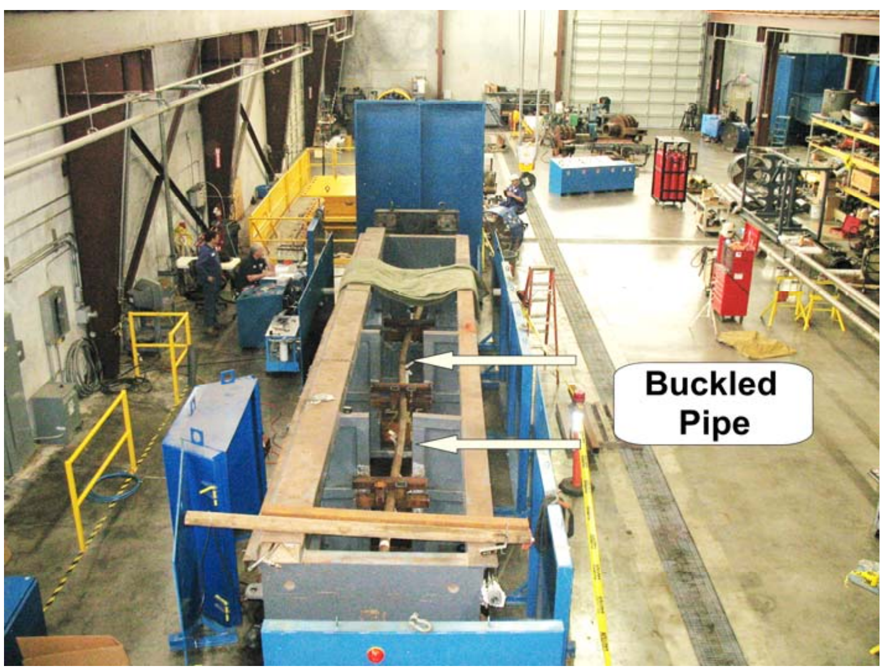


Drill pipe in test frame. Axial load is applied to drill pipe with 4 hydraulic cylinders not visible in photograph.



Displacement transducer (yoyo) used to measure axial deflection or change in length of the pipe as load is applied.

Anti buckling members were welded to the test frame to decrease the unsupported length from 29 ft to about 7.33 ft. With the anti buckling members, the buckling strength was about 234,500 lbs. Calculated buckling strength for unsupported pipe is 11,775 lbs.



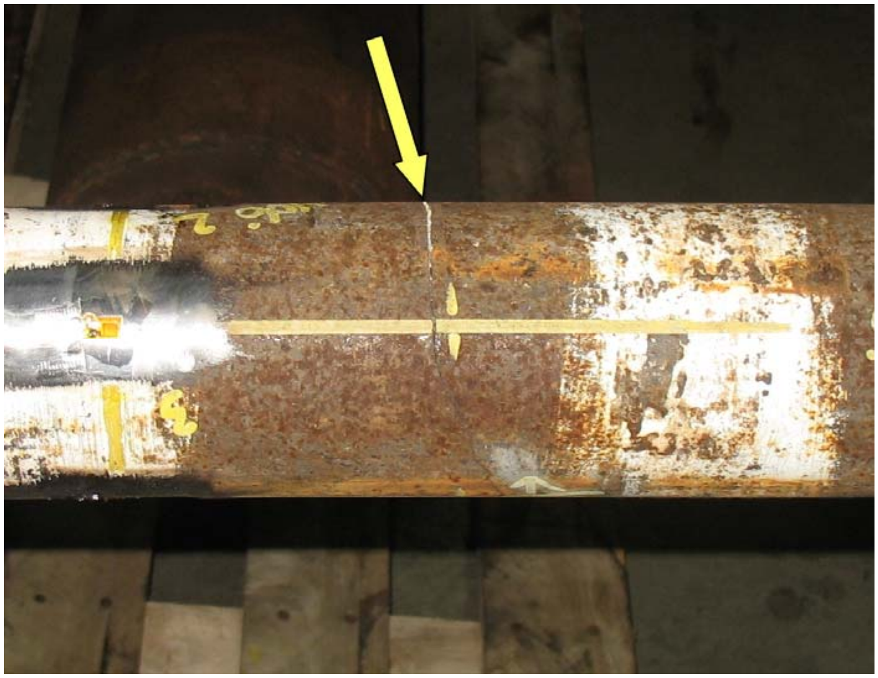
Buckled pipe in frame during compression test. A maximum axial compressive load of 234,519 lbs was applied to the pipe.

Pipe being made ready for torsion test. Truck mounted tongs applied torque to one end of pipe. Other end held to prevent rotation.

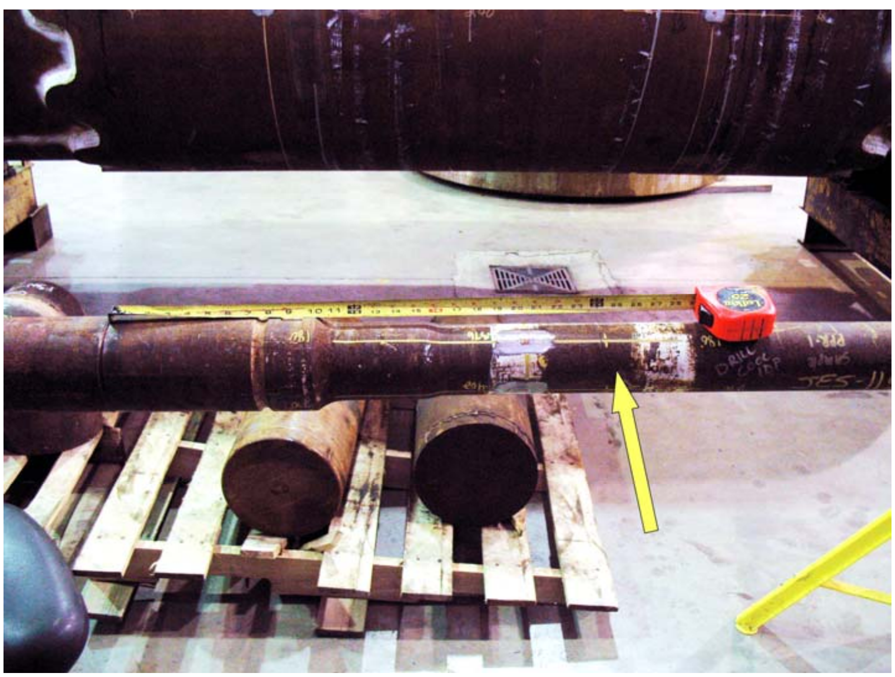
End of pipe in chain vise to prevent rotation during torsion test.

End of pipe before being gripped by tongs in torsion test. 77 degree mark, when vertical, indicates degrees rotation for torque of 33,413 ft-lbs, yield torque of pipe.

Final position of pipe during torsion test. Pipe had an angle of twist greater than 77 degrees which means it went beyond its torsional yield strength of 33,413 ft-lbs. No leakage at 200 psi occurred from the tool joint bore to the insulated annulus.

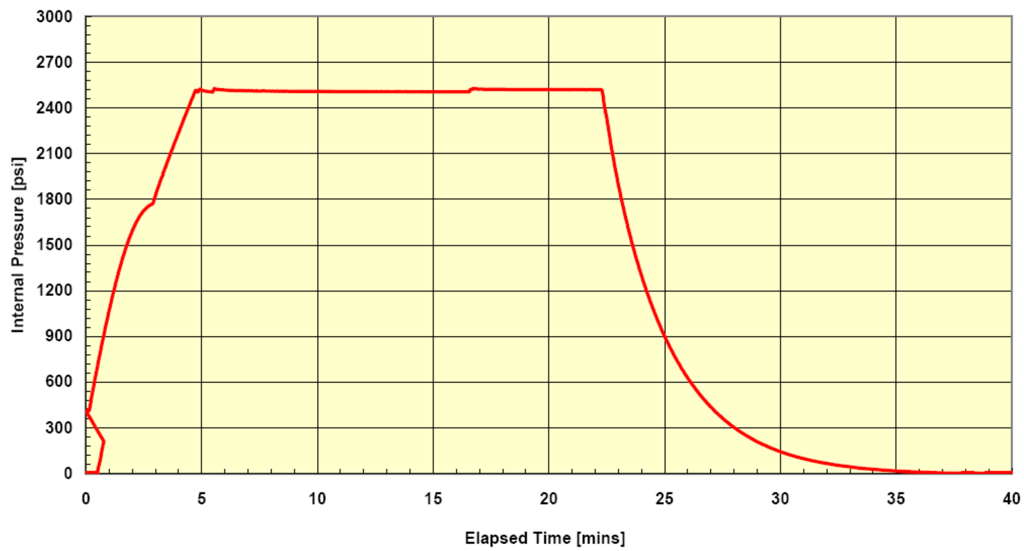


Fatigue crack in pipe. Pipe developed fatigue crack after oscillating 1,362,900 cycles with an outer fiber stress of 18,000 psi adjacent to the external upset.



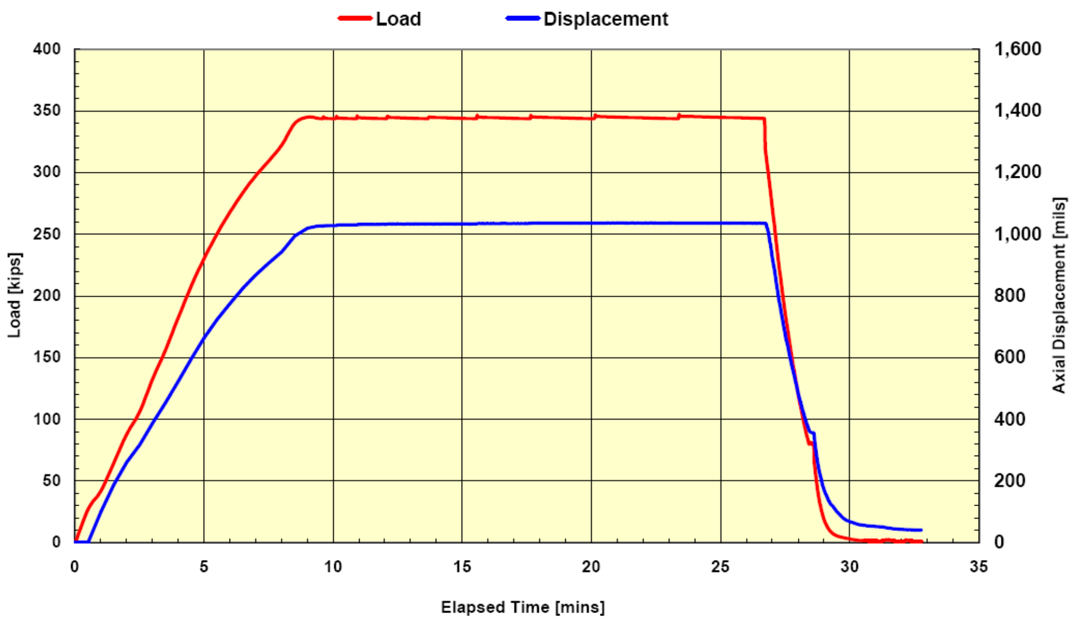
Location of fatigue crack on pipe. Crack is 24 inches from pin make-up shoulder.

Appendix B
Pressure Test 1, Pipe #1



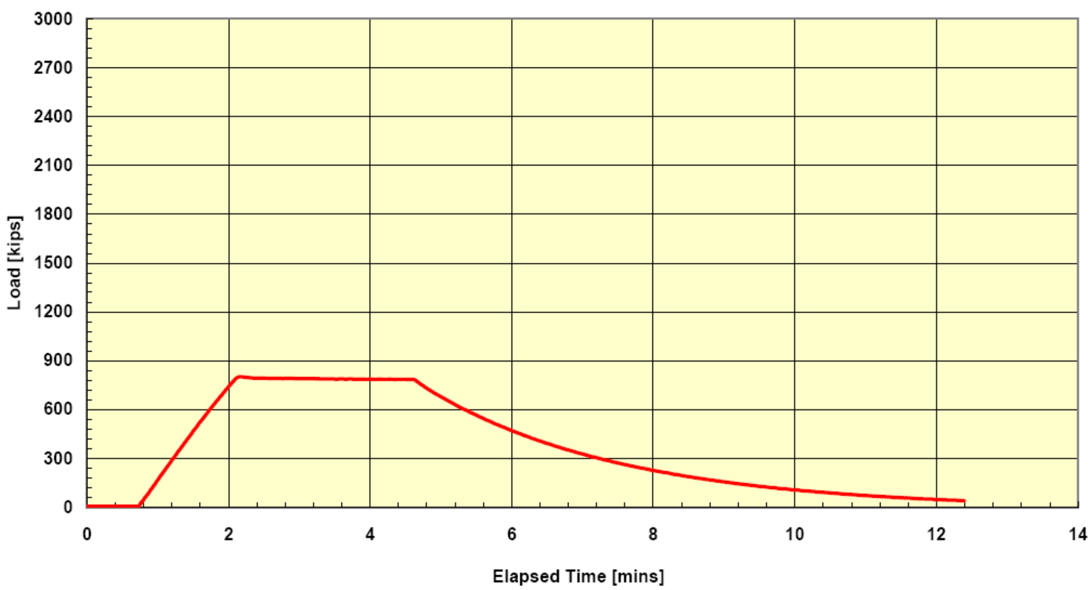
Plot of pressure test before tensile test of pipe #1. Pressure of 2528 psi was applied to bore of drill pipe assembly and held for 15 minutes. A decrease in pressure would have indicated a leak where the inner tube was mated with the tool joint.

Appendix C
Tensile Test Pipe #1



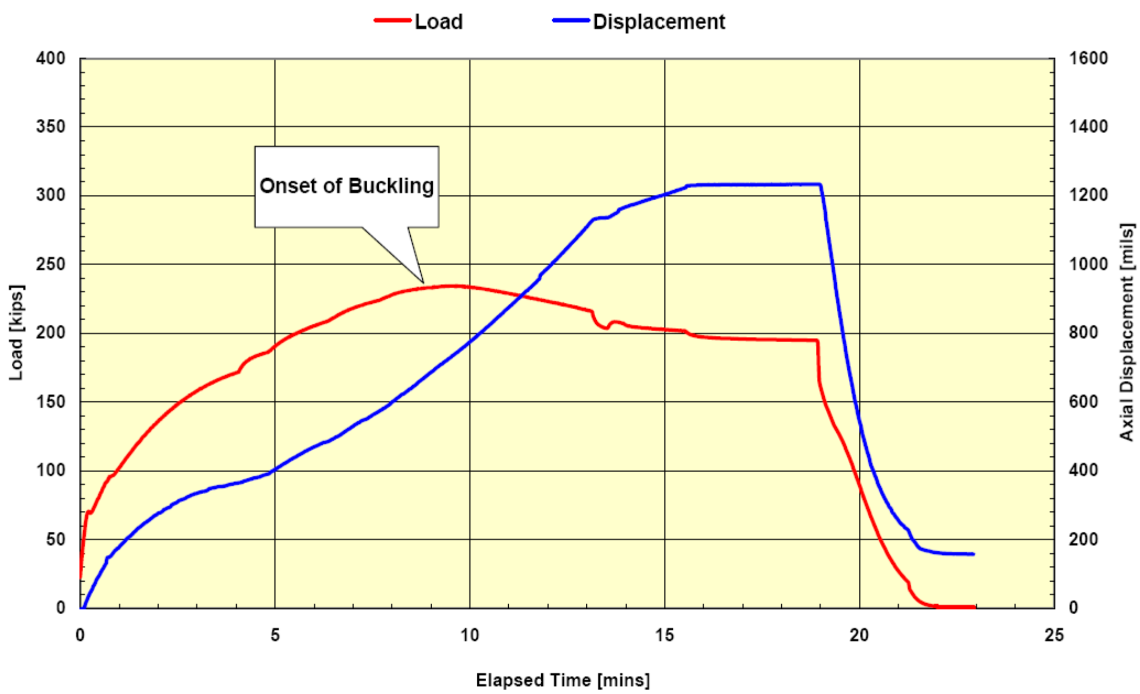
Plot of load and displacement from tensile test of pipe #1. Load was increased from 0 to 347,268 lbs and held for more than 15 minutes. Axial stretch in pipe was measured as tensile load was applied. Pipe stretched 1.037 inches.

Appendix D
Pressure Test 2, Pipe #1



Plot of pressure test after tensile test of pipe #1. Pressure of 802 psi was applied to bore of drill pipe assembly before leakage occurred on box end.

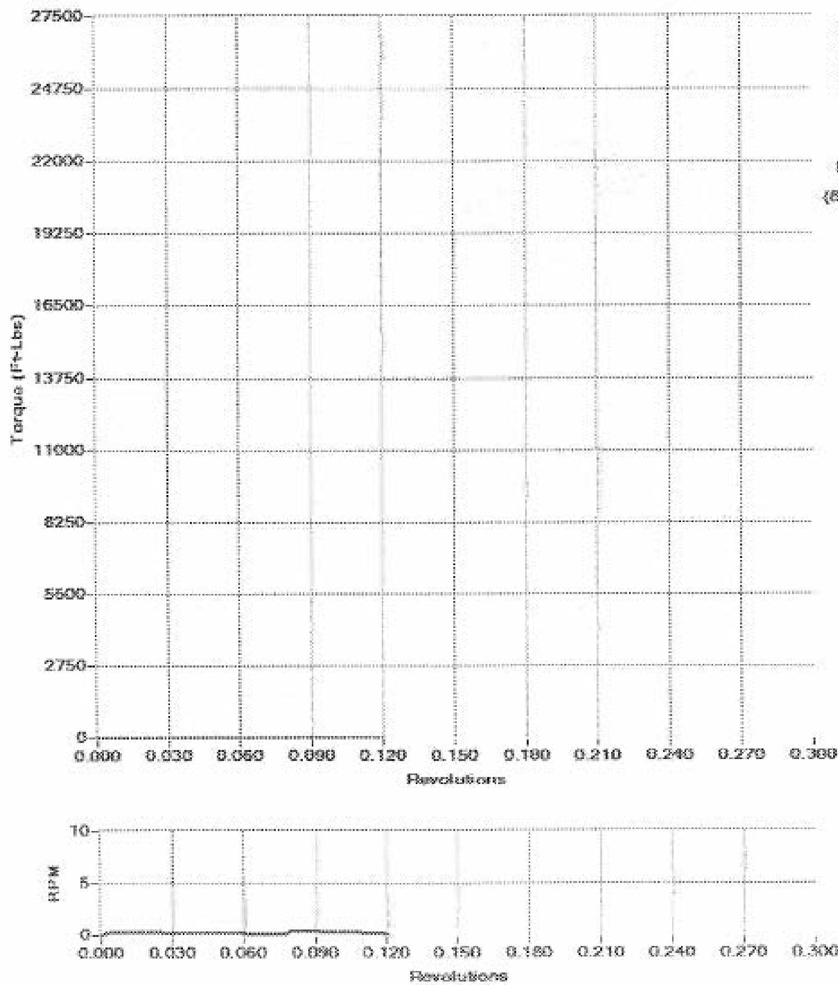
Appendix E
Compression Test Pipe #2



Plot of load and displacement from compression test of pipe #2. Compressive load was increased from 0 to a maximum of 234,519 lbs. The onset of buckling prevented the load from going above this value. The pipe was supported at approximately 7 ft intervals. The axial deformation of the pipe, which includes the effect of buckling, was 1.234 inches.

Appendix F

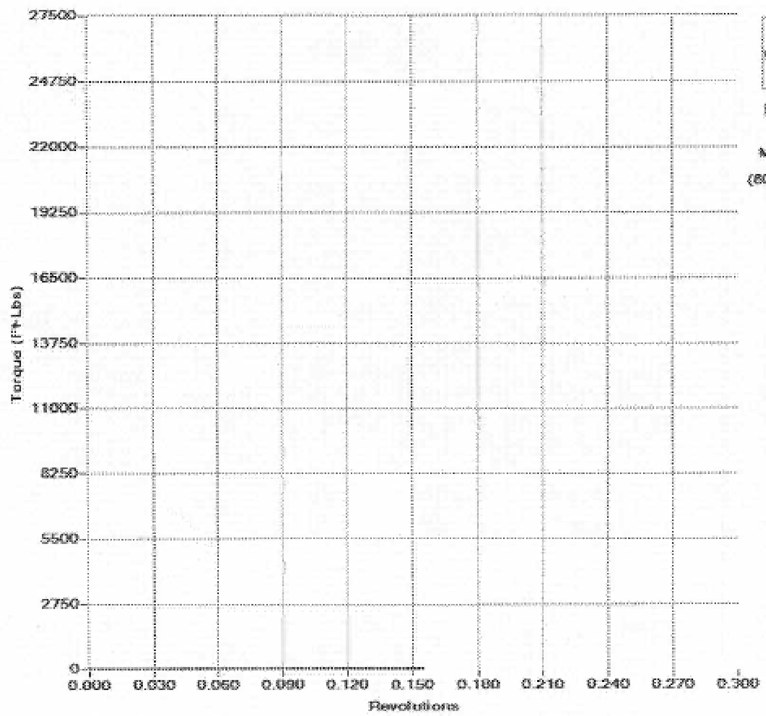
Torque Test Data

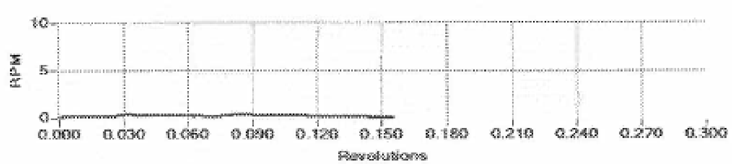


Dispatch@
Bucking
Masters.com
(800) 682-3928

Date: 08-29-2007	Time: 13.10:49
Job: 07-782	Joint: 1
Cust:	STRESS ENG.
Rep:	
PO Number:	115443 JES
Location:	WESTLAND
Description:	3 1/2 DRILL PIPE ASSY.
Operator 1: P.CORTEZ	Operator 2: J.RODRIGUEZ
Dump Torque:	7458 Ft-Lbs.
Dump Torque Reset:	6739 Ft-Lbs.
Arm Length:	12.0 In.
Encoder Pulse/Rev:	33897.0
Final Torque:	**0 Ft-Lbs.**
Peak Torque:	**0 Ft-Lbs.**
Final Revolutions:	**0.120**
Average RPM:	**0.1**
Data Points:	**4136**
Ave Points/Rev:	**34489.1**
Turn Direction:	**Clockwise**
Shoulder Torque:	**0 Ft-Lbs.**
Shoulder Revs:	**0.000**
Delta Torque:	**0**
Delta Turn:	**0.000**
Result:	Accept
Comments:	TEST
Comments:	
Comments:	

Trial Make-up Torque from tongs twisted pipe 0.120 revolutions or 43.2 degrees. Only revolutions were recorded because torque load cell is on back-up tongs. Back-up tongs were not used because end of pipe was held in chain vise.

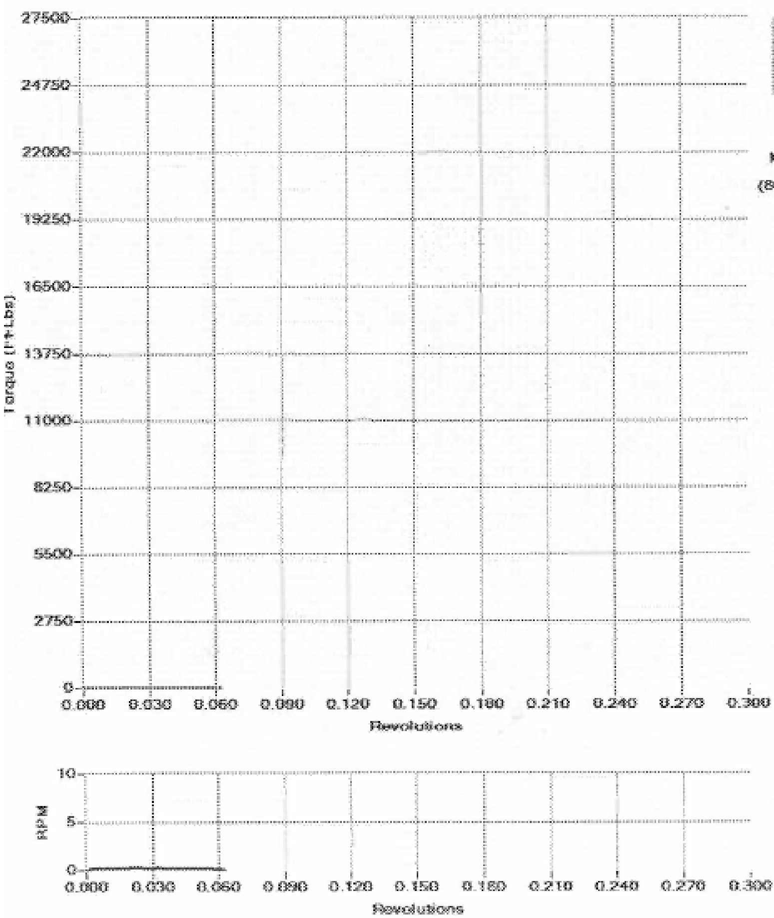




Dispatch@
Bucking
Masters.com
(800) 682-3928

Date: 08-29-2007	Time: 13:28:49
Job: 07-782	Joint: 2
Cust:	STRESS ENG.
Rep:	
PO Number:	115443 JES
Location:	WESTLAND
Description:	3 1/2 DRILL PIPE ASSY
Operator 1: P.CORTEZ	Operator 2: J.RODRIGUEZ
Dump Torque:	7488 Ft-Lbs.
Dump Torque Reset	6739 Ft-Lbs.
Arm Length:	12.0 In.
Encoder Pulse/Rev:	33897.0
Final Torque:	**0 Ft-Lbs.**
Peak Torque:	**0 Ft-Lbs.**
Final Revolutions:	**0.154**
Average RPM:	**0.2**
Data Points:	**3079**
Ave Points/Rev:	**19929.1**
Turn Direction:	**Clockwise**
Shoulder Torque:	**0 Ft-Lbs.**
Shoulder Revs:	**0.000**
Delta Torque:	**0**
Delta Turn:	**0.000**
Result:	Accept
Comments:	1 ST. TRY
Comments:	
Comments:	

Torque Test. Pipe had torque induced that caused a twist of 0.154 revolutions or 55.4 degrees. Rotation was stopped at this point.



Dispatch@
Bucking
Masters.com
(800) 882-3928

Date: 08-29-2007	Time: 13:30:42
Job: 07-782	Joint: 3
Cust:	STRESS ENG.
Rep:	
PO Number:	115443 JES
Location:	WESTLAND
Description:	3 1/2 DRILL PIPE ASSY.
Operator 1: P.CORTEZ	Operator 2: J.RODRIGUEZ
Dump Torque:	7468 Ft-Lbs.
Dump Torque Reset:	6739 Ft-Lbs.
Arm Length:	12.0 In.
Encoder Pulse/Rev:	33897.0
Final Torque:	**0 Ft-Lbs.**
Peak Torque:	**0 Ft-Lbs.**
Final Revolutions:	**0.062**
Average RPM:	**0.1**
Data Points:	**1891**
Ave Points/Rev:	**30465.4**
Turn Direction:	**Clockwise**
Shoulder Torque:	**0 Ft-Lbs.**
Shoulder Revs:	**0.000**
Delta Torque:	**0**
Delta Turn:	**0.000**
Result:	Accept
Comments:	2 ND. TRY
Comments:	
Comments:	

Completion of Torque Test. Rotation was resumed and pipe was torqued an additional 0.062 revolutions or 22.3 degrees for a total of 77.8 degrees. This angle of twist reaches the torsional yield of the pipe.

Appendix G
Handlog – Tensile Test

STRESS ENGINEERING SERVICES INC.

13602 Westland East Blvd.
Houston, Texas 77041
281.469.2177

MOHR ENGINEERING DIVISION

BY: AJW CLIENT: Drill Cool Systems, Inc. SHEET 1 OF
DATE: 6-20-07 SUBJECT: 3½ IDP Test JOB NO.: ~~115448~~ 115443

File 115448_P1.com 1st Gas Press Test

Time	Scan	Press	Load	Disp	
11:37	360	2516	0	0	Start 15 min Hold
11:53	1330	2520	0	0	End Hold No Bbls.

File 115448_T1.com 1st Tension Test

			Kips		
12:46	30	0	343.9	1028	Start 15 min hold
13:03	1005	0	344.2	1035	End Hold

File 115448_P2.com

13:15	150	635	0		Leak at Box End

Appendix H
Calculation Sheets

CLIENT: Cool Drill

PROJECT: 115443

CALCULATION BY: Jack Smith PE

$E \equiv 30 \cdot 10^6 \cdot \frac{lb}{in^2}$

Liner stretch and collapse 3-1/2 13.30 Drill Pipe

$\rho_s \equiv 0.283 \cdot \frac{lb}{in^3}$

$Sy := 135000 \frac{lb}{in^2}$

$D_p := 3.5in$ $L_p := 31.5ft$ $Lpb := 30ft$

$d_p := 2.764in$ $t_n := 0.368in$

$A_p := \frac{\pi}{4}\left(D_p^{\ 2} - d_p^{\ 2}\right)$ $A_p = 3.621 \cdot in^2$

$I_p := \frac{\pi}{64}\left(D_p^{\ 4} - d_p^{\ 4}\right)$ $I_p = 4.501 \cdot in^4$

Stretch of 30 ft long S135 drill pipe pipe body

$\delta := \frac{Sy \cdot Lpb}{E}$ $\delta = 1.62 \cdot in$ $Fc := A_p \cdot Sy = 488824.78\,lb$

Stretch of 30 ft long 1018 liner @ 70 ksi

$Sl := 70000 \frac{lb}{in^2}$

$\delta l := \frac{Sl \cdot Lpb}{E}$ $\delta l = 0.84 \cdot in$

difference $\delta - \delta l = 0.78 \cdot in$

Stress in 1018 when compress 0.78 inches

$\sigma l := \frac{(\delta - \delta l) \cdot E}{Lpb}$ $\sigma l = 65000 \cdot \frac{lb}{in^2}$

$Dprem := D_p - 2 \cdot t_n + (2) \cdot (0.8) \cdot t_n$ $Dprem = 3.353 \cdot in$

$Aprem := \frac{\pi}{4}\left(Dprem^2 - d_p^{\ 2}\right)$ $Aprem = 2.829 \cdot in^2$

90% premium tensile load

$Ft := 0.9 \cdot Aprem \cdot Sy$ $Ft = 343683\,lb$

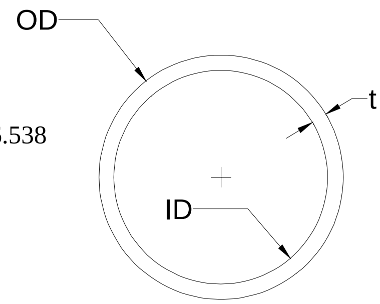
$Aprem \cdot Sy = 381870.168\,lb$

$Ys := 55000 \cdot \frac{lb}{in^2}$ $\quad$ $Dl := 2.375 \cdot in$ $\quad$ $t := 0.065in$

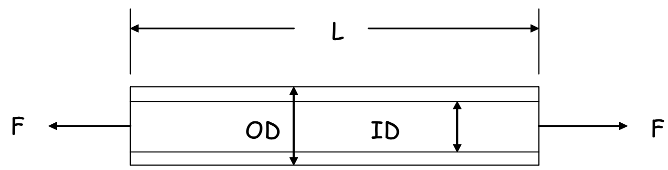
$\sigma_t := Ys$

$dl := Dl - 2 \cdot t$ $\quad$ $dl = 2.245$ $\quad$ $G3 := \frac{Dl}{t}$ $\quad$ $G3 = 36.538$

$P := \frac{2 \cdot t \cdot Ys}{dl}$ $\quad$ $P = 3184.855 \cdot \frac{lb}{in^2}$



Collapse Pressure of inner tube



External pressure $\quad$ $Po := 000 \cdot \frac{lb}{in^2}$ $\quad$ Internal Pressure $\quad$ $Pi := 0 \cdot \frac{lb}{in^2}$

$Ys := 55000$

Wall Thickness $\quad$ $t := 0.065in$ $\quad$ $G3 := \frac{Dl}{t}$ $\quad$ $G3 = 36.538$

Material Yield Strength

Constant A $\quad$ $A := 2.8762 + 1.0679 \times 10^{-6} \cdot Ys + 2.1301 \cdot 10^{-11} \cdot Ys^2 - 5.313 \cdot 10^{-17} \cdot Ys^3$

$A = 2.991$

Constant B $\quad$ $B := 0.026233 + .50609 \cdot 10^{-6} \cdot Ys$

$B = 0.054$

Constant C $\quad$ $C := -465.93 + .030867 \cdot Ys - 1.0483 \cdot 10^{-8} \cdot Ys^2 + 3.6989 \cdot 10^{-14} \cdot Ys^3$

$C = 1206.198$

$$G9 := \frac{3 \cdot \frac{B}{A}}{2 + \frac{B}{A}}$$ $\quad$ $G9 = 0.027$

Constant F

$$F := \frac{4.695 \cdot 10^{7} \cdot G9^{3}}{Ys \cdot \left(G9 - \frac{B}{A}\right) \cdot (1 - G9)^{2}}$$

$F = 1.989$

Constant G

$$G := F \cdot \frac{B}{A}$$

$G = 0.036$

D/t Intersection between yield strength collapse and plastic collapse A11

$$Dtyp := \frac{\left[(A-2)^{2} + 8 \cdot \left(B + \frac{C}{Ys}\right)\right]^{.5} + A - 2}{2 \cdot \left(B + \frac{C}{Ys}\right)}$$

$Dtyp = 14.81$

D/t intersection between plastic collapse and transition collapse

$$Dtpt := Ys \cdot \frac{A - F}{C + Ys \cdot (B - G)}$$

$Dtpt = 25.008$

D/t intersection between transition collapse and elastic collapse

$$Dtte := \frac{1}{G9}$$

$Dtte = 37.207$

Minimum yield strength collapse pressure

$$Py := \frac{2 \cdot Ys \cdot (G3 - 1)}{G3^{2}}$$

$Py = 2928.133$

Minimum plastic collapse pressure

$$Pp := Ys \cdot \left(\frac{A}{G3} - B\right) - C$$

$Pp = 321.6$

Minimum transition collapse pressure

$$Pt := Ys \cdot \left(\frac{F}{G3} - G\right)$$

$Pt = 1016.364$

Minimum elastic collapse pressure

$$Pe := \frac{4.696 \cdot 10^{7}}{G3 \cdot (G3 - 1)^{2}}$$

$Pe = 1017.608$

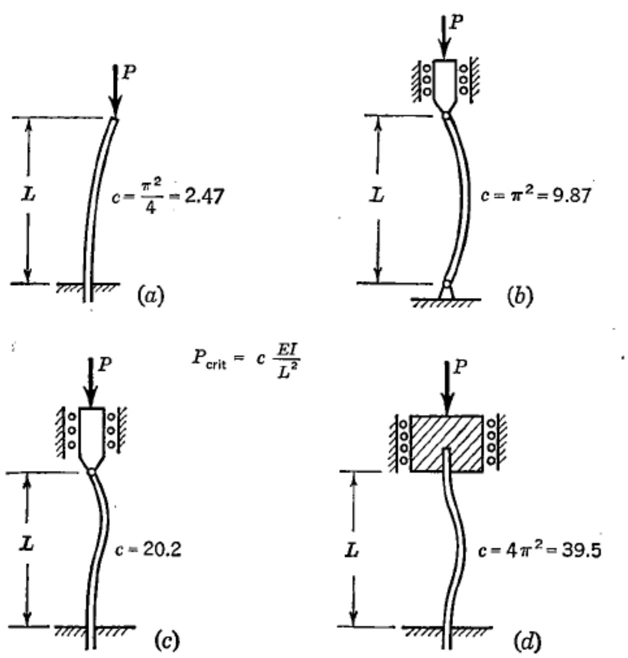
$$\text{Mode} := \begin{cases} \text{"Yield"} & \text{if } G3 \le Dtyp \\ \text{otherwise} & \\ \quad \begin{cases} \text{"Plastic"} & \text{if } G3 \le Dtpt \\ \text{otherwise} & \\ \quad \begin{cases} \text{"Transition"} & \text{if } G3 \le Dtte \\ \text{"Elastic"} & \text{otherwise} \end{cases} \end{cases} \end{cases}$$

$\text{Mode} = \text{"Transition"}$

$$\text{Pcollapse} := \begin{cases} Py & \text{if } G3 \le Dtyp \\ \text{otherwise} & \\ \quad \begin{cases} Pp & \text{if } G3 \le Dtpt \\ \text{otherwise} & \\ \quad \begin{cases} Pt & \text{if } G3 \le Dtte \\ Pe & \text{otherwise} \end{cases} \end{cases} \end{cases}$$

$\text{Pcollapse} = 1016.364$

Buckling



$n := 1$

FIG. 9.17. Buckling loads for (a) clamped-free, (b) hinged-hinged, (c) clamped-hinged, and (d) clamped-clamped columns. In each case the constant c shown is to be inserted in the formula $P_{crit} = cEI/L^2$.

Mom of Inertia

The drill pipe, during the compression test, was lateraly supported in four place. Distance between lateral supports was 7' 4" (7.33 ft).

Each end of pipe was condition (c). The two center sections of pipe was condition (d).

$L := 7.33\text{ft}$

$c1 := 20.2$

$$Pcr1 := \frac{c1 \cdot E \cdot I}{L^2} = 377221\,\text{lb}$$

$c2 := 39.5$

$$Pcr2 := \frac{c2 \cdot E \cdot I}{L^2} = 737634.9\,\text{lb}$$

CLIENT: Drill Cool

PROJECT: 115443

CALCULATION BY: Jack Smith PE

$Sy := 110000 \frac{lb}{in^2}$ $E \equiv 30 \cdot 10^6 \cdot \frac{lb}{in^2}$

$Ap(D, d) := \frac{\pi}{4}\left(D^2 - d^2\right)$ $s \equiv 100 \cdot ft$

$Ip(D, d) := \frac{\pi}{64}\left(D^4 - d^4\right)$ $\rho_s \equiv 0.283 \cdot \frac{lb}{in^3}$

Tosional Deflection of Drill Pipe

$D := 3.5in$	**OD**	
$d := 2.764in$	**ID**	
$L := 29ft$	**Pipe length between upsets**	
$Ys := 135000 \frac{lb}{in^2}$	**Yield Strength**	
$\tau := \frac{Ys}{\sqrt{3}}$	**Max Shear Stress**	
$G := 11.5 \cdot 10^6 \frac{lb}{in^2}$	**Modulus of Rigidity**	
$J := 2 \cdot Ip(D, d)$	**Polar moment of inertia**	$J = 9.002\, in^4$
$T := \frac{2\tau \cdot J}{D}$	**Torsional Strength**	$T = 33413\, ft \cdot lb$
$Ta := 25850ft \cdot lb$	**Applied Torque**	
$\theta := \frac{Ta \cdot L}{J \cdot G}$	**Angle of Twist**	$\theta = 59.743\, deg$

Appendix I
Calibration Sheets

Specialized Tech Services

PO Box 355 Dobbin, Tx 77333

CALIBRATION CERTIFICATE

CUSTOMER:	**MOHR Engineering Division**		
13602 Westland East Blvd			
Transducer Make:	Sensotec	Transducer Model:	TJE/0743-06TJG
Transducer S/N:	648357	Transducer Range:	0 - 5000 psi
Indicator Make	Daytronic	Indicator Model:	3270
SHUNT #	**2506**	S/N:	SES-17
Reference and testing conditions:		979.312 gals	17°C +/- 1.5 deg

CALIBRATION READINGS (as left)

ACTUAL (psi)	READING 1 (psi)	READING 2 (psi)	PERCENT ERROR % of FS
0	0	0	0.000
500	499	500	-0.010
1000	1000	1000	0.000
2000	2001	2001	0.020
3000	3001	3001	0.020
4000	4000	4000	0.000
5000	4997	4998	-0.050

All readings within manufacturer tolerence (+/- .5% F.S.)

The values stated in this certificate of accuracy were determined by direct comparison to a Pressurements S/N 61205 Deadweight Tester calibrated by an independent testing laboratory and is traceable to N.I.S.T.

Technician	L. Wilson	DATE:	December 02, 2006
SIGNED:		RECALL:	December 02, 2007

Specialized Tech Services

PO Box 355 Dobbin, Tx 77333

CALIBRATION CERTIFICATE

CUSTOMER:	**MOHR Engineering Division**		
13602 WESTLAND EAST BLVD			
Transducer Make:	Sensotec	Transducer Model:	TJE/7090-05TJG-01
Transducer S/N:	833321	Transducer Range:	0 - 10000 psi
Indicator Make	Daytronic	Indicator Model:	3270
SHUNT #	4762	S/N:	SES-D03
Reference and testing conditions:		979.312 gals	28°C +/- 1.5 deg

CALIBRATION READINGS (as left)

ACTUAL (psi)	READING 1 (psi)	READING 2 (psi)	PERCENT ERROR % of FS
0	0	0	0.000
1000	998	998	-0.020
2000	2000	2000	0.000
4000	4002	4002	0.020
6000	6002	6002	0.019
7999	8000	8000	0.010
9999	9994	9994	-0.050

All readings within manufacturer tolerence (+/- .5% F.S.)

The values stated in this certificate of accuracy were determined by direct comparison to a Pressurements S/N 61205 Deadweight Tester calibrated by an independent testing laboratory and is traceable to N.I.S.T.

Technician	L. Wilson	DATE:	July 7, 2006
SIGNED:		RECALL:	July 7, 2007

Specialized Tech Services

PO Box 355 Dobbin, Tx 77333

CALIBRATION CERTIFICATE

CUSTOMER:	**Mohr Engineering Division**		
13602 Westland East Blvd			
Transducer Make:	Sensotec	Transducer Model:	TJE
Transducer S/N:	660177	Transducer Range:	0 - 10000 psi
Indicator Make	Daytronic	Indicator Model:	3270
SHUNT #	**4992**	S/N:	SES-17
Reference and testing conditions:		979.312 gals	17°C +/- 1.5 deg

CALIBRATION READINGS (as left)

ACTUAL (psi)	READING 1 (psi)	READING 2 (psi)	PERCENT ERROR % of FS
0	0	0	0.000
1000	1000	1000	0.000
2000	2002	2002	0.020
4000	4004	4004	0.040
6000	6002	6002	0.020
8000	7998	7998	-0.020
10000	9992	9992	-0.080

All readings within manufacturer tolerence (+/- .5% F.S.)

The values stated in this certificate of accuracy were determined by direct comparison to a Pressurements S/N 61205 Deadweight Tester calibrated by an independent testing laboratory and is traceable to N.I.S.T.

Technician	L. Wilson	DATE:	December 02, 2006
SIGNED:		RECALL:	December 02, 2007

APPENDIX C – SCOPE OF WORK: DEVELOPMENT OF INSPECTION PROCEDURE

Phase I -- Phase I of the project will involve the following items:

1. Development of a testing protocol to determine the response of the insulated drill pipe to standard inspection methods:
   a. The program will test the effectiveness of the following inspection methods:
      • Full Length Ultrasonic Testing (FLUT)
      • Ultrasonic Wall Thickness Inspection
      • Ultrasonic Slip/Upset Inspection
      • Electromagnetic Inspection (EMI)
   b. Each inspection method's level of effectiveness will be analyzed based on comparison of the test results for the same set of drill pipe test joints with and without the insulation installed.
   c. The number of test joints will be chosen by consultation between TH Hill Associates and Drill Cool Systems.
   d. Standardized flaws (notches, radial holes, etc.) will be specified for each inspection method. Such flaws will be machined into a reference standard joint, which will be used to standardize each inspection process.
   e. The protocol will outline the standardization and inspection processes as well as the methodology for data collection and documentation.

2. Implementation of the experimental inspection program:
   a. The drill pipe test joints will be obtained, and the standardized flaws will be machined into the reference standard joint. The machined flaws will be accurately measured to ensure proper dimensions and orientations.
   b. The experimental inspections will be performed and completely monitored. The inspections will be performed at a testing facility in Houston.
   c. Data generated during standardization and inspection will be collected and recorded.

3. A report will be prepared that outlines the details and results of the experimental inspection program.

Phase II -- Phase II of the project will involve the following items:

1. Analysis of data generated in Phase I:
   a. The data collected in Phase I will be analyzed to study the drill pipe response (with and without insulation) to the standard inspection methods.
   b. Using the inspection results for the test joints without insulation as the standard, the accuracy and effectiveness of each inspection method on the insulated drill pipe will be analyzed and documented.

2. Development of the inspection program and acceptance criteria for insulated drill pipe:
   a. This process will be based on the conclusions of the Phase I analysis.
   b. The program will be designed to address inspection considerations that are specifically related to insulated drill pipe.
   c. The recommended inspection program and acceptance criteria will be presented in a final report with the supporting data and conclusions from Phase I.

APPENDIX D – INSPECTION PLAN PROCEDURE

Summary:
In support of the Inspection Requirements of the Insulated Drill Pipe (IDP) the following summary describes operations that each of the six pieces of drill pipe will undergo during this phase of testing.

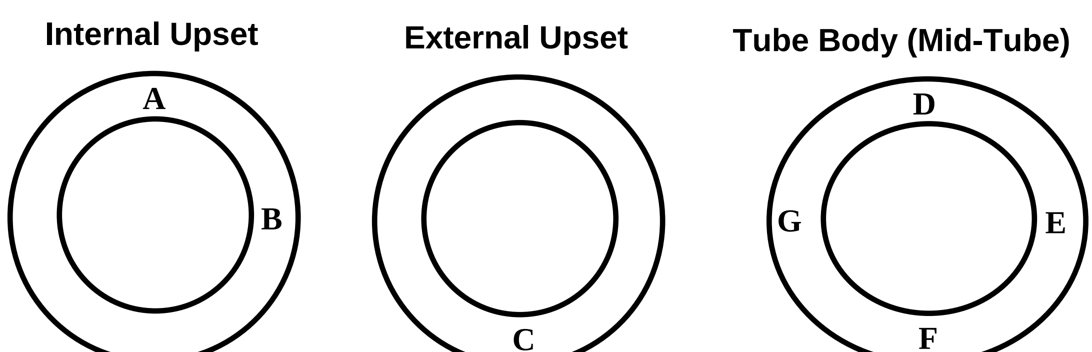
Sample #1 (condition: premium)
6-5/8" S-135 27.7 lb/ft with 5-1/2FH Connections (approx length: 32.0ft)
Sample #2 (condition: premium)
6-5/8" S-135 27.7 lb/ft with 5-1/2FH Connections (approx length: 32.0ft)
Sample #3 (S/N NN97469) (condition: new)
5" G-105 19.5 lb/ft with NC50 Connections (approx length: 31.5ft)
Sample #4 (S/N NN97454) (condition: new)
5" G-105 19.5 lb/ft with NC50 Connections (approx length: 31.5ft)
Sample #5 (S/N K8261) (condition: used)
3-1/2" X-95 13.3 lb/ft with NC38 Connections (approx length: 31.0ft)
Sample #6 (S/N K8252) (condition: used)
3-1/2" X-95 13.3 lb/ft with NC38 Connections (approx length: 31.0ft)

Description of Basic Work Flow for Inspection Testing:
All samples will undergo a total of three inspections. The general flow of this work is as follows:

Step#1: Baseline Inspection
This will be completed to fully characterize each piece of drill pipe in its current state prior to any work being completed. This is done to verify the condition of the pipe and ensure the accuracy of the results.

Each piece of pipe will be oriented radially prior to inspection as to ensure repeatability in inspection and aid in comparing the inspection results. The 0 degree (12 o'clock) position will be positions at the top, vertical point of the pipe. This point corresponds to the point of thread termination (near the shoulder) on the pin of each sample. Prior to inspection a 0 degree line will be scribed into the tool joint (pin end of each sample).

Step #2: Machining of Notch Geometry and IDP Parent Pipe Modifications
Each sample of drill pipe will be machined with a careful selection of notches based on TH Hill's DS-1 Category 5 inspection methods. To minimize machining costs each sample of IDP will receive a custom selection of notches per the following:



General Description of Notches
Type A – 2 Transverse, 5% of wall Thickness (W.T.) from OD & ID, ½” Length
Type B – 2 Oblique at 6° left hand transverse, 5% of W.T. from OD & ID, ½” Length
Type C – 1 Transverse 5% W.T. form OD (External Upset)
Type D – 2 Transverse, 5% of W.T. form OD & ID, ½” Length
Type E – 2 Longitudinal, 5% of W.T. from OD & ID, ½” Length
Type F – 2 Oblique at 6° left hand transverse, 5% of W.T. from OD & ID, ½” Length
Type G – 1 Wall Reduction 5% of W.T. on ID
DS-1 Required Notch Dimensions
Length: 0.5” max
Width: 0.040” max
Depth: 5% of nominal wall ±0.004”

The following Chart indicates the notches to be included on each sample of IDP involved in this test.

	Type A	Type B	Type C	Type D	Type D	Type E	Type F	Type G
Sample #1 (6-5/8”)	X	X	X	X	X	X	X	X
Sample #2 (6-5/8”)	X			X				X
Sample #3 (5”)	X			X	X	X	X	X
Sample #4 (5”)	X			X				X
Sample #5 (3-1/2”)	X	X	X	X				X
Sample #6 (3-1/2”)	X			X				X

It should also be noted that any machining required to convert the Drill Pipe Samples into IDP will be completed during this step. Additionally the fill ports required for IDP will oriented at the 0 degree position described previously.

Step #3: Pre-Fabrication Inspection
Each sample will undergo an additional baseline inspection that will now capture and verify the modifications created in Step #2. The Notch Geometries will also be verified and documented by the inspection company.

Step #4: IDP Fabrication
The drill pipe samples will now undergo the process to fully convert them to insulated drill pipe (IDP). This includes the installation of the liner, termination sleeve, and insulation material. During fabrication certain manufacturing errors will be built into some of the samples as indicated below:

Sample #1: Standard Assembly
Sample #2: Standard Assembly
Sample #3: Standard Assembly with biased liner at Mid Tube
Sample #4: Standard Assembly
Sample #5: Standard Assembly with incomplete insulation fill
Sample #6: Standard Assembly with liner failure and biased liner at Mid Tube

Step #5: IDP Inspection

This final inspection will allow the operator to confirm detection of the machined geometries determined in Steps 2 and 3 but also investigate the possible detection of manufacturing flaws. It may also be desired to produce a full Visonic 3-D image of Sample #1 to aid in the presentation of the results.

Step #6: Post Inspection Destructive Testing & Inspection

It may be desirable to provide a partial section of Samples #3, #5, & #6 to reveal the true characteristics of the manufacturing defects. These sections can then be used to aid in the interpretation of the Inspection Results produced in Step #5.

APPENDIX E – SCOPE OF WORK FOR MARKET SURVEY

Phase 1: Market Analysis

1. Identify HT basins in the US using Spears' proprietary HT database.
2. Using the SmithSTATS database, identify and quantify the activity (average # of rigs per year) of E&P companies drilling in US HT basins (identified in the previous step) during the past three years.
3. Build a list of drilling managers and/or drilling engineers working for those active HT E&P companies (identified in the previous step) using directories from RigData, the Society of Petroleum Engineers, etc.
4. Prepare two questionnaires that address the specific study requirements: one to be used for interviewing E&P companies drilling HT wells and one to be used for interviewing directional drilling service companies working on HT wells.
5. Interview 20 drilling managers and/or drilling engineers working for the E&P companies identified in step 2 using the study questionnaire.
6. Interview five directional drilling service companies to evaluate their perception of the need and impact of using insulated drill pipe for US HT drilling using the study questionnaire.
7. Tabulate interview responses from E&P companies and directional drilling service firms and analyze the data.
8. Prepare forecast of US HT drilling activity by region through 2010 by combining interview results with Spears' proprietary forecast of US drilling activity.
9. Gather information on the estimated maximum operating temperatures, operating life under HT conditions, and cost of failure for selected drilling equipment and materials including LWD/MWD tools, mud motors, and drilling fluids.
10. Gather information on current and expected rig rates and HT well costs.
11. Prepare a report and presentation summarizing the results of the market survey and HT drilling forecast.

APPENDIX F – MARKET SURVEY RESULTS

Drill Cool

In support of the development of insulated drill pipe for the US high temperature drilling market

Prepared by

Spears & Associates, Inc.
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www.spearsresearch.com

14 October 2007

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Research Objectives

Market research to identify the high temperature market for insulated drill pipe in the US

In support of Drill Cool's initiative to develop an insulated drill pipe for application in very high temperature oil and gas wells, Spears & Associates proposed the following work plan:

In Phase 1 of the proposed work plan (the market analysis), *Spears & Associates will interview 20 or more operators drilling high temperature wells in one or all of the following areas: Gulf of Mexico, East Texas/North Louisiana, and South Texas. The research team will contact these operators to determine which ones are drilling high temperature wells.*

Operators drilling high temperature wells in the Gulf of Mexico, East Texas/North Louisiana, and South Texas will be interviewed to identify the following:

What size (diameter) drill pipe is being used.
Which operators are willing to test insulated drill pipe in their high temperature wells.

During August, September and October 2007, Spears & Associates contacted approximately 100 oil and gas companies currently drilling in regions of the US known to include high temperature (>300 degrees F) wells. The firm also contacted all high-end directional drilling service companies known to be working in these same high temperature regions.

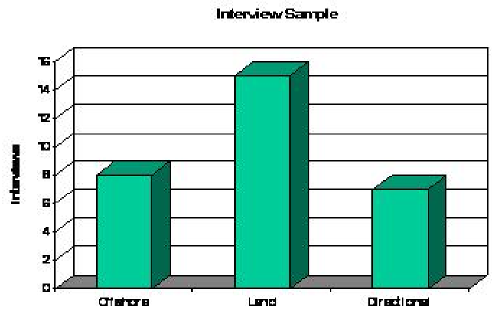
During this period the US oil and gas industry was undergoing record high drilling activity in many regions. Interviewing was slow. The firm often went several days without successfully conducting an interview. This challenge came about in part because the drilling engineers responsible for these projects are extremely busy and found the topic of insulated drill pipe to fall outside their scope of immediate concern.

3

Market Research Analysis

4

Research Sample



Source of Names

To identify oil companies actively drilling in known high temperature regions, Spears used the Smith STATS database of weekly drilling activity to highlight the operators drilling this year along the Texas, Louisiana and Alabama/Mississippi coastal areas and the Gulf of Mexico. Spears cross-referenced this current deep drilling with RigData's operator directory to get contact information for drilling engineers possibly working on these projects.

Offshore Spears used an Offshore Data Services publication to identify operators drilling extremely deep (or long) wells in likely regions of high temperature.

How Do We Know Where HT Wells Are Drilled?

Spears & Associates developed a computer model during the 'Nineties that indexed each county in the US and each depth zone in those counties with the known or assumed thermal profile of geological basins.

We assumed that *high temperature* is around 300 degrees F because the current state of downhole drilling electronics has that as a practical limit. Service companies and operators in past projects have indicated that temperatures below 300 F posed little problem with existing standard downhole gear.

During this project we discovered that basins may be slowly cooling as gas reserves are removed and downhole pressures drop. Unlike interviewing a dozen years ago, we found little evidence of >300 F zones being encountered on land along the US Gulf Coast. Additionally, we believe that HT drilling is only a small fraction of all deep drilling…and this fraction is not growing.

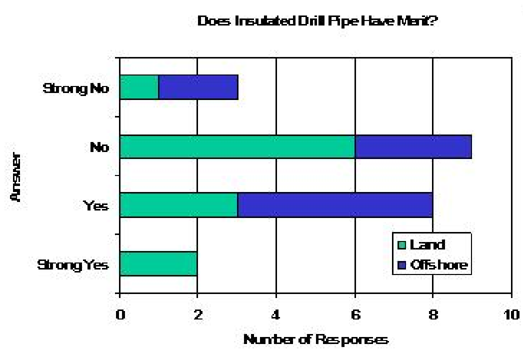
Interview Process

Once a likely operator was identified, Spears would call the company to identify the most likely person responsible for the drilling project. Spears would then call and, most frequently, leave a voice mail with that individual regarding our topic of interest and the scope of the questions we intended to cover. If an operator was cooperative, we would either immediately conduct the interview by telephone, or schedule a time at a later date to conduct the discussion.

We called every operator actively drilling along the Gulf Coast and had successful interviews with 15 on land. We also called every operator drilling deep wells in the Gulf of Mexico and successfully interviewed 8.

Directional drillers are all clients of Spears. We used our existing sources within those service companies to identify people of authority in high temperature techniques. We successfully interviewed 7 directional drillers.

Does IDP Have Merit?



Summary

After describing Drill Cool's insulated drill pipe concept to drilling engineers and managers, Spears asked the open-ended question, does the idea have merit?

Verbatim responses can be seen in the interview summaries later in this report.

Slightly more operators and service companies thought the idea of insulated drill pipe did not have merit than did. This is to be expected for any technology that has yet to be introduced or that is still in its early stages of adoption. We are not concerned by this bias toward "no".

Interview Comments

Maybe. I'd have to see it work.

My (colleague in charge of HT drilling technologies) is not keen on the insulated pipe routine. From a technology standpoint, he doesn't think it will actually work and, if it does, believes it will entail long and rigorous testing and modification before anyone would use it in a real application.

I think insulated drill pipe is a good idea…we're going to need something to keep downhole electronics cool in these very deep, very hot Gulf of Mexico fields that have been discovered. MWD benefits from cooler mud.

But here is Drill Cool's challenge: Chevron's analysis shows that cooling the rock face in a deep, hot well creates massive amounts of formation damage, so they are actually thinking of heating the mud rather than cooling the mud.

Interview Comments

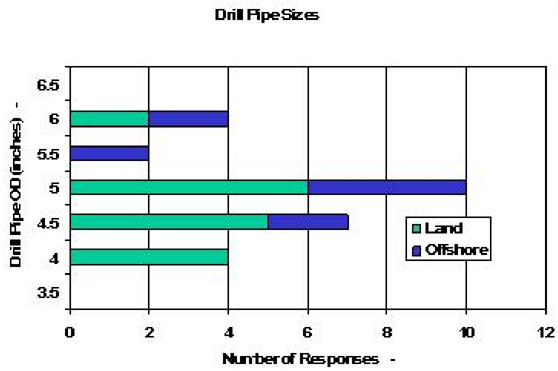
Insulated drill pipe would start being an attractive alternative around 300 degrees F.

I've got no experience on which to base an answer (if the insulated drill pipe has merit or not). I guess it'd be useful once we hit about 270 degrees.

High temperature results in more down time, due to shorter life of mud motors, aging of elastomers. Insulated drill pipe that delivers cooler mud could be a benefit from longer life of elastomers and seals, improved life of electronics.

The benefit from insulated drill pipe would be found in being able to make fewer trips to change out MWD and mud motors. There might be longer life for elastomers and seals. There could be savings in tool rentals as well as rig time for avoiding extra trips.

Drill Pipe Diameter



Summary

The chart to the right shows the size of drill pipe being used by operators drilling high temperature wells along the Gulf Coast.

Given the small sample size, we have indicated drill pipe sizes to the nearest half inch. For example, one operator said he used 5-7/8" drill pipe. We have round this to 6".

5" is the most common OD. 4.5" OD is second, but operators were concerned that insulated drill pipe might restrict ID in pipe approached 4"... and operators are absolutely not willing to sacrifice ID for a variety of reasons.

Interview Comments

You've got to be able to get fishing tools through your ID. So that will be your limiting factor. If I can't get standard fishing down the pipe to free my stuck pipe or to get out my MWD unit, then you can forget about bringing your insulated pipe out to my well.

We use 5 ½" drill pipe. An insulated drill pipe needs to have an ID that is as large as possible.

5 7/8" and 5" would be the best drill pipe sizes. Going down to 4" hampers operations. Sometimes I see times of up to eleven hours to circulate mud.

The smaller 4" drill pipe must be able to accommodate fishing tools.

Interview Comments

For these South Texas land wells we use both 5" and 4" drill pipe. Whatever Drill Cool brings out has to be useful in an oil based environment. And the insulation coating must be durable.

The diameters represented by the tool company (out of California, we think) would not allow the MWD tools to be run and ended up costing ECA about 15 days of rig time due to stuck tools and circulation issues.

Needs to be close to diameters of existing drill strings.

The operator would not want to have a special string for the full length of hole. I'd agree with the other Halliburton engineer who suggested plus or minus 10% in diameters.

Drilling engineers must be convinced that the insulated drill pipe can deliver the tension and the compression dynamics of an offshore well or a deviated land well.

Technical Issues

Summary

The number one concern of drilling engineers considering the insulated drill pipe concept is restricted internal diameter.

Some were specific: IDP must allow standard fishing tools to pass through. Others were less specific, but just as adamant.

The second greatest requirement was that IDP had to come in standard drill pipe sizes. They did not want to deal with unique or rare pipe sizes that would require new handling tools and new drilling fluid hydraulics programs.

Interview Summary

ID must allow fishing tools:	3
ID must be as large as possible:	4
Need high annular velocity:	1
Must allow for oil-based muds:	1
Wired pipe is the direction of deep water:	1
Require standard drill pipe sizes:	2
Must stand up to drilling jar use:	2

Market Drivers & Drilling Forecast

9

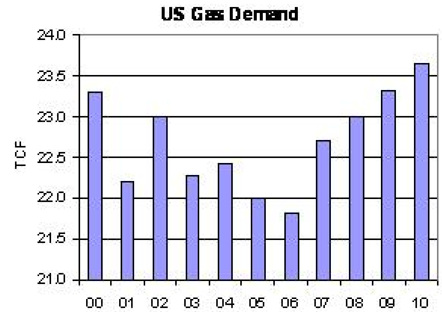
Oil & Gas Demand

Market Analysis

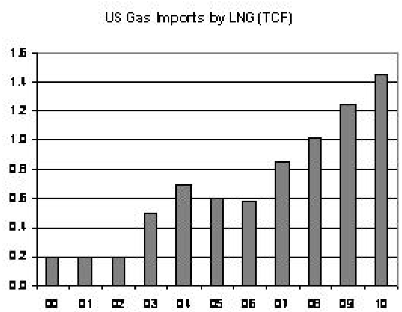
US gas demand is projected to grow 4% in 2007,

Much of that demand growth will be satisfied by LNG. LNG imports will be up 45% this year and 20% in '08. Because LNG is delivered primarily in late summer and early fall, US gas storage is filling up earlier and earlier, depressing demand for newly produced gas during that season.

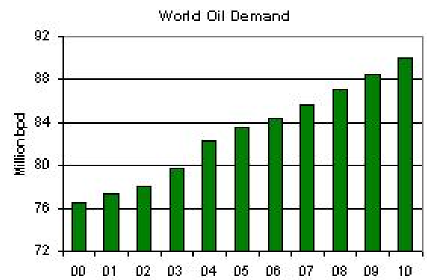
As a result, we expect weak gas prices in September-October to become a regular feature of the gas market.



Source: EIA, Spears



Source: EIA, Spears



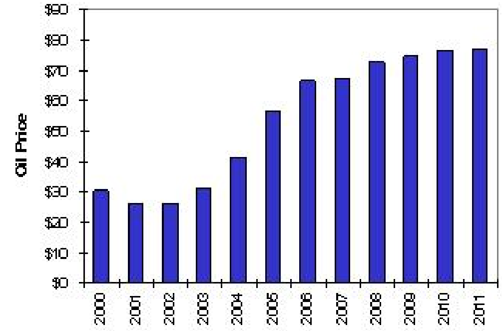
Source: EIA, Spears

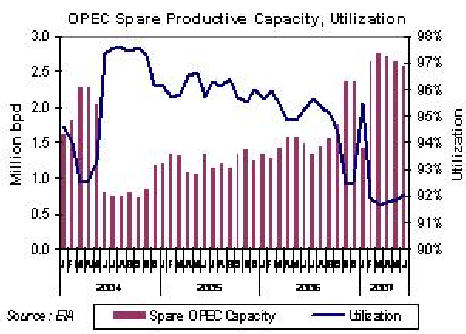
Oil & Gas Prices

Market Analysis

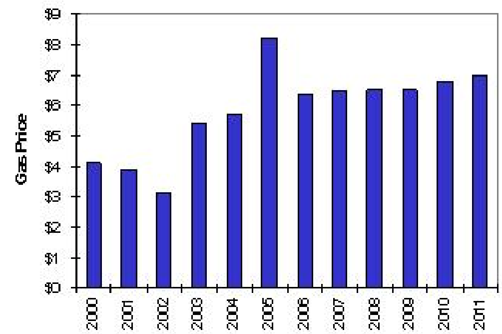
US spot gas prices are expected to average $6.50 per mmbtu through 2011. The LNG imports discussed on the prior page, combined with a remarkable increase in land-based natural gas production from shales and coals keeps plenty of gas in the system.

US spot oil prices are expected to trade in the $70-$75 per barrel range. As the chart below indicates, spare oil productive capacity is tiny...only a couple percent of daily oil demand. This is an all time low and points toward high oil prices through the rest of the forecast period and beyond.





Source: EIA



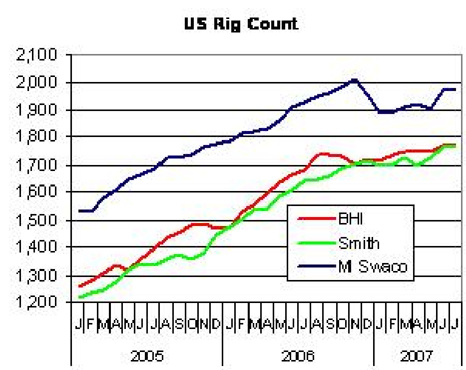
Drilling Rig Counts

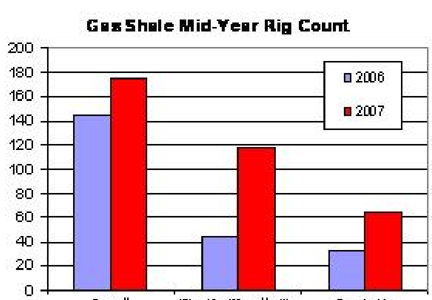
Market Analysis

Spears & Associates tracks several drilling rig surveys – Baker Hughes, Smith and M-I Swaco.

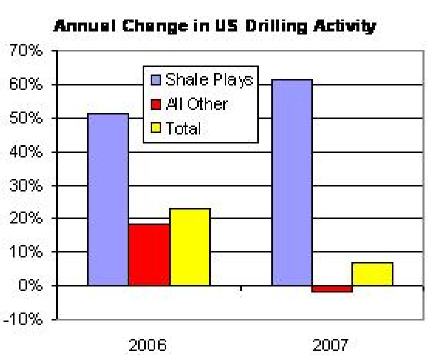
These service company rig counts have increased 4%-5% for the first seven months of '07 vs. 8%-14% for same period in '06. The growth rate in drilling is clearly slowing.

The graph to the lower right shows that 2007 growth is highly concentrated in shale plays (Barnett, etc.) that currently account for 20% of US activity. These shale plays and other unconventional plays are generally shallow and fairly benign.





Source: Smith Tool



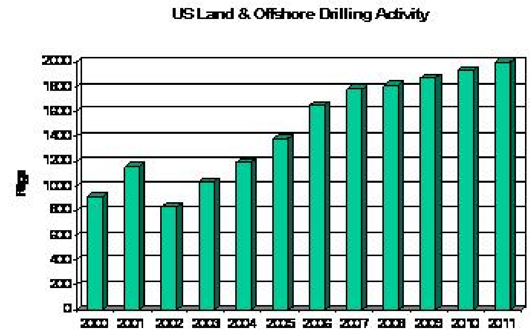
US Drilling Forecast

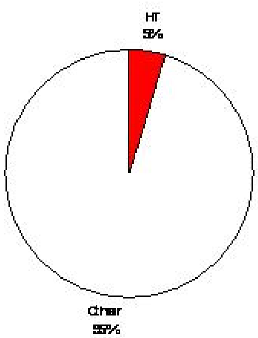
Market Analysis

The chart to the right plots US drilling activity, both land and offshore. It projects the Baker Hughes active drilling rig count. More rigs than this are working; this is the subsegment that is drilling a new well.

The table may be found by double-clicking on the chart.

The rapid growth portion of the market cycle is now finished due to softening natural gas prices and rapidly soaring drilling and completion costs. Until costs decline and gas prices rise, drilling growth will be flatish.





HT Analysis

Seen later in the report, only about 5% of the wells drilled on land each year can be considered high temperature.

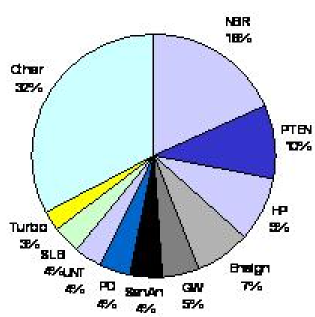
We have defined HT is the temperature at the bottom of the well. The entire drilling process did not encounter high temperatures – only the part within the reservoir is the HT component, generally speaking.

Global Land Drilling Market

Market Analysis

Last year we projected 21% growth for 2007, but the market turned in late 2006 and is falling. We now think that this year's market will be down 8% from the prior year. Steadily rising global rig activity has been more than offset by flat North American drilling and declining dayrates. At this point we are projecting a fall of 4% for 2008 as US dayrates continue to deteriorate in the face of rising rig supply.

Source of the information on this page is Spears' Oilfield Market Report.



Forecast

The global land drilling market will continue to rise through the forecast period due to very strong market fundaments outside North America.

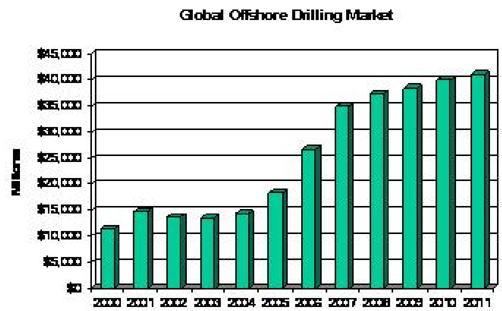
We believe that the North American market will self-correct over the next year or to, launching a new cycle of growth once positive economics of drilling have been introduced.

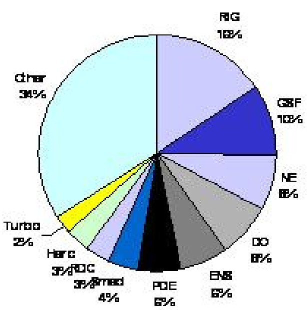
Global Offshore Drilling Market

Market Analysis

Offshore contract drilling is the "boomiest" of the market segments we track. Hampered by oversupply most years, when this market turns, it turns hard. As the neighboring chart shows, this market doubled in just over two years once the supply of rigs became slightly lower than the demand for rigs.

Due to soaring dayrates, especially in deeper water rigs, downhole drilling technologies are being employed at a record pace in hopes that the number of days to drill can be reduced. These drilling technologies include rotary steerable directional drilling, fixed cutter bits, one-trip multiple completions, rigless reentry systems...





Forecast

Assuming that oil prices remain well above $50, we believe that the offshore contract drilling market will rise into 2008 or perhaps into 2009, whereupon a flood of additional drilling rigs will enter the market and the increased competition will drive down dayrates. We expect lower dayrates in the deeper waters starting in 2009 or 2010, markedly dampening sales growth.

US Drilling Costs

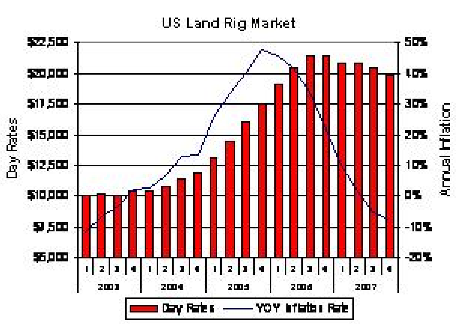
Market Analysis

The table to the right shows estimated US well costs in Q3 2007. Costs on land and on the Shelf are now declining as demand falls.

The US land well shown is a 10-15,000' well into a conventional, normal temperature well. Cost includes completions...frac jobs, packers, completion fluids.

The GOM Shelf well can include high temperature situations for part of the drilling process. HT wells on land in South Texas and in South Louisiana can approach this cost as well.

And deepwater wells are quite expensive.



Well Costs (US)

Q3 2007

Spending Category	Land US	GOM Shelf	GOM Deepwater
Contract Drilling	$315,000	$2,500,000	$36,500,000
Oil Country Tubular Goods	$415,000	$1,100,000	$3,000,000
Directional Drilling Services	$80,000	$500,000	$1,000,000
Wellheads/Trees	$50,000	$200,000	$1,000,000
Wireline Logging	$100,000	$250,000	$1,000,000
Drilling & Completion Fluids	$100,000	$300,000	$800,000
Completion Equipment & Services	$25,000	$150,000	$500,000
Rental & Fishing Services	$100,000	$200,000	$500,000
Logging-While-Drilling	$0	$200,000	$350,000
Solids Control & Waste Management	$50,000	$100,000	$350,000
Drill Bits	$50,000	$100,000	$250,000
Mud Logging	$20,000	$125,000	$250,000
Stimulation	$200,000	$350,000	$450,000
Inspection & Coating	$25,000	$50,000	$200,000
Cementing	$50,000	$100,000	$200,000
Casing & Cementation Products	$15,000	$50,000	$100,000
Casing & Tubing Services	$30,000	$50,000	$100,000
Production Testing	$5,000	$25,000	$100,000
Coiled Tubing Services	$50,000	$100,000	$400,000
Well Servicing	$50,000	$0	$0
TOTAL	$1,750,000	$6,450,000	$47,050,000

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High Temperature Drilling Forecast

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High Temperature Drilling

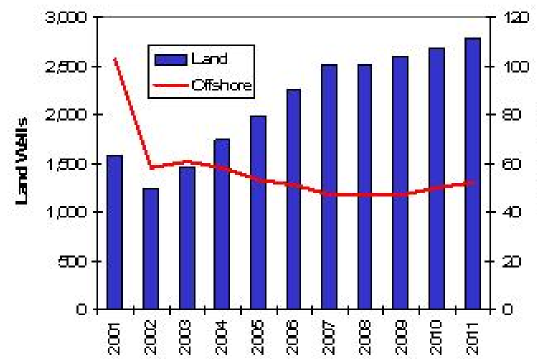
Market Forecast

The chart to the right plots high temperature new well drilling in the US for land and offshore wells. The table driving the graph is seen below.

4-5% of the wells drilled on land in the US are considered high temperature.

6-7% of the wells drilled in the Gulf of Mexico are high temperature.

HT is considered any well with a bottom hole temperature above 300 degrees F.



US HT Wells

Region	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
US HT Wells Drilled											
Land	1,585	1,244	1,463	1,744	1,993	2,252	2,515	2,518	2,592	2,686	2,786
Offshore	103	58	61	58	53	51	47	47	47	50	52
Total	1,688	1,302	1,524	1,802	2,047	2,304	2,561	2,565	2,639	2,736	2,838
Total US Wells Drilled											
Land	34,724	27,255	32,057	38,210	43,669	49,341	55,094	55,165	56,788	58,852	61,034
Offshore	1,516	859	898	853	787	757	687	687	697	731	767
Total	36,240	28,114	32,955	39,063	44,456	50,098	55,781	55,852	57,485	59,583	61,801

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Operator Interviews

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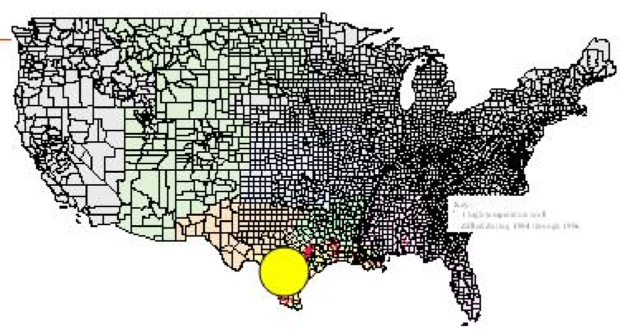
Operator A



Merits & benefits of the insulated drill pipe system

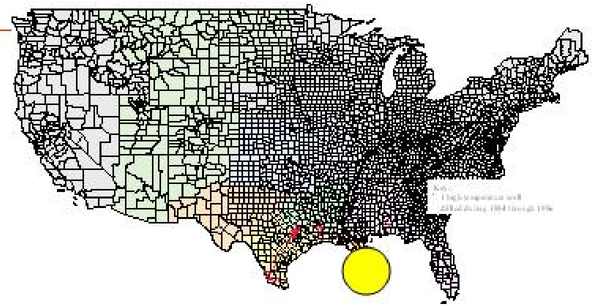
Maybe. I'd have to see it work.

Technical issues

You've got to be able to get fishing tools through your ID. So that will be your limiting factor. If I can't get standard fishing down the pipe to free my stuck pipe or to get out my MWD unit, then you can forget about bringing your insulated pipe out to my well.

Other comments

Operator B



Merits & benefits of the insulated drill pipe system

My (colleague in charge of HT drilling technologies) is not keen on the insulated pipe routine. From a technology standpoint, he doesn't think it will actually work and, if it does, believes it will entail long and rigorous testing and modification before anyone would use it in a real application.

Technical issues

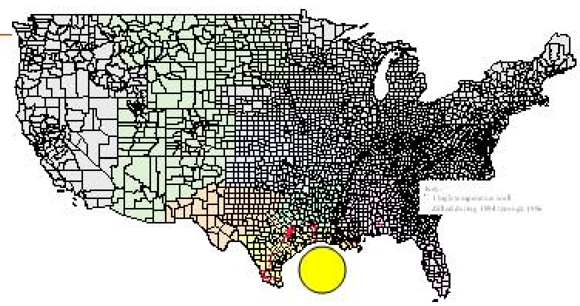
Halliburton and Schlumberger are both looking at starting an HT tool development and both claim to have an interested partner in the wings. We think Total is the partner and is playing both of them, but will only choose one to work with. Obviously, the service companies are trying to get BP on board also.

This is a costly technology area since the HT electronics are very much at or beyond the state of the absolute technology.

Other comments

We are not aggressively pursuing this technology as we only have one or two wells that may need the technology. The rub is, in Gulf of Mexico ultra deep gas, where a discovery could necessitate a few tools, we're not going to drill all that many wells.

Operator C



Merits & benefits of the insulated drill pipe system

High temperatures make it a requirement to circulate cooler mud to the bottom of well.

I think some of the benefits could be longer life of elastomers in the motors, improved life of electronics, lower cost MWD/RST systems, and fewer trips. Possibly less expensive mud additives.

Insulated drill pipe would start being an attractive alternative around 300 degrees F.

Technical issues

Yes temperature is an issue. We running into temperatures up to 350 degrees, but problems start at about 300 degrees.

Total well depths up to 20,000 feet. Most wells are directional.

But I've got a well going in the GOM South Tambalier 81. 18,000', 61' water depth. Vertical exploratory hole.

We use 5 ½" drill pipe. An insulated drill pipe needs to have an ID that is as large as possible.

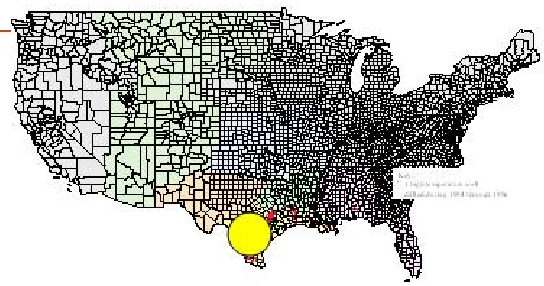
Other comments

High temperature reduces tool life, and that means more round trips, lost time.

When Drill Cool builds this first string of insulated drill pipe may they contact you about possibly running it in one of your wells?

Yes.

Operator D



Merits & benefits of the insulated drill pipe system

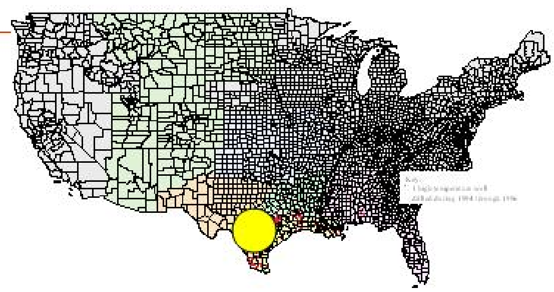
I can't see any benefit for us. Not at present.

I'm not encountering temperatures over 230 degrees F and we're drilling to 14,000 feet. For our steerable systems, we have no temperature problems.

Technical issues

Other comments

Operator E



Merits & benefits of the insulated drill pipe system

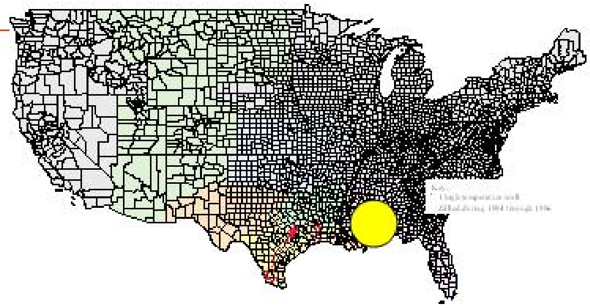
I'm drilling in Hidalgo County, Texas to 15,000'. Vertical, development wells.

High temperature is not a problem.

Technical issues

Other comments

Operator F



Merits & benefits of the insulated drill pipe system

High temperature results in more down time, due to shorter life of mud motors, aging of elastomers. Insulated drill pipe that delivers cooler mud could be a benefit from longer life of elastomers and seals, improved life of electronics.

So it would probably help the mud motors, but there'd probably be no benefit to lower cost of drilling fluid additives.

Technical issues

I want 8-½" and larger hole size. Any drill pipe I use, I'd want to see the main benefit would be in keeping annular velocity high.

5 7/8" and 5" would be the best drill pipe sizes. Going down to 4" hampers operations. Sometimes I see times of up to eleven hours to circulate mud.

I want maximum ID and minimum OD.

Other comments

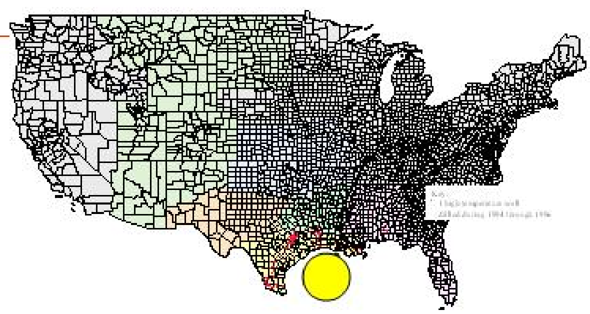
I believe in keeping temperature down by circulating mud faster.

Rankin County, Mississippi, 16,875' vertical development.

When Drill Cool builds this first string of insulated drill pipe, may they contact you about possibly running it in one of your wells?

No, not at this time.

Operator G



Merits & benefits of the insulated drill pipe system

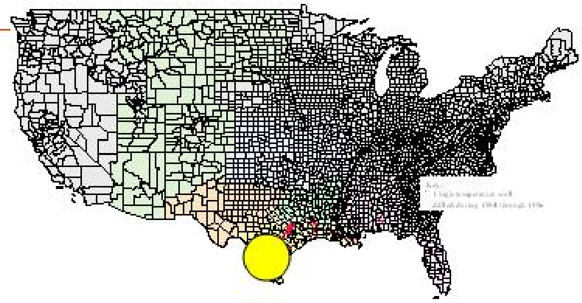
High temperature is never a problem. Rarely a problem

Technical issues

Other comments

We're drilling a well in the Gulf of Mexico West Cameron 62 where the well depth is 23,900 feet, the water depth is pretty shallow – 36 feet. It is a directional gas well and, quite frankly, we don't have anything like a temperature problem.

Operator H



Merits & benefits of the insulated drill pipe system

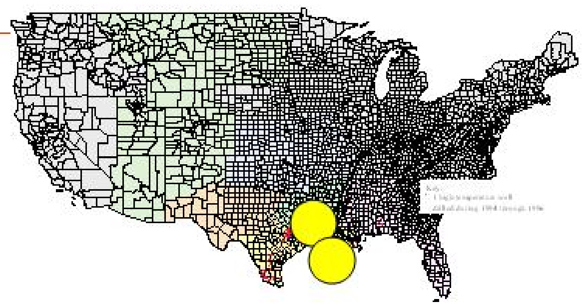
Temperature is not an issue. Top temperature we run into is 300 degrees F.

Technical issues

Other comments

We're drilling in Kenedy County, Texas to 15,000 depth, vertical. These are development wells.

Operator J



Merits & benefits of the insulated drill pipe system

High temperature is generally not an issue. No hot wells currently.

Technical issues

Other comments

Operator J has locations in both Louisiana and Gulf of Mexico. We have a well going in Louisiana to 20,000 feet, and GOM wells are 13,300 to 16,500 feet in depth.

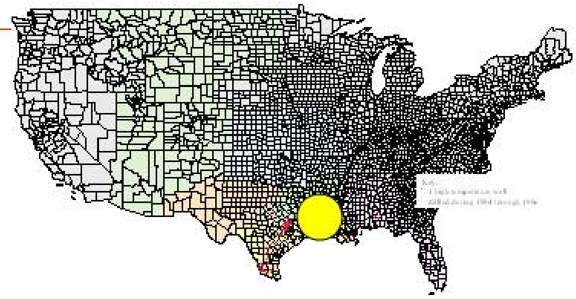
Operator K

Merits & benefits of the insulated drill pipe system

We encounter temperatures of 280 to 300 degrees F. We're drilling to depths of 17,700 to 18,100 feet. Vertical wells.

High temperatures in drilling can cause problems with mud, tools, and fishing and tool repair

I've got no experience on which to base an answer (if the insulated drill pipe has merit or not). I guess it'd be useful once we hit about 270 degrees.



Technical issues

We're drilling with 4 ½".

Other comments

Vermilion County, Louisiana. 15,100' vertical development wells.

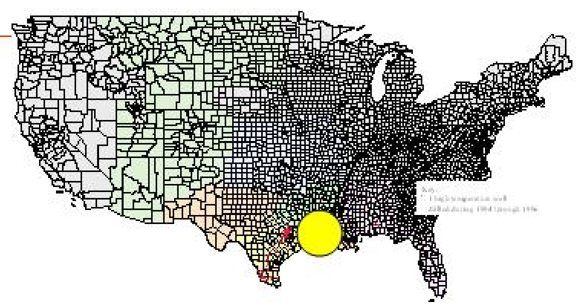
Operator L

Merits & benefits of the insulated drill pipe system

I'm drilling in Louisiana's Cameron County down to 16,000 feet.

With these wells we've got no problems. I don't think South Louisiana is a prospect for insulated drill pipe

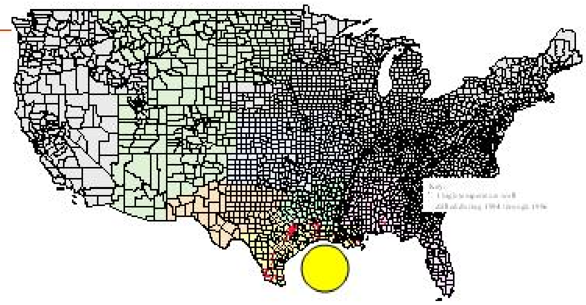
NOTE: Spoke with drilling-completions manager,



Technical issues

Other comments

Operator M



Merits & benefits of the insulated drill pipe system

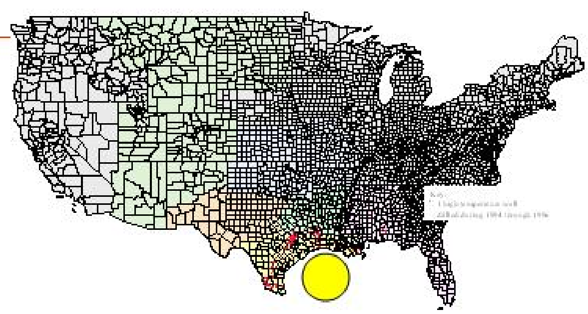
We're not going to be a prospect for insulated drill pipe. All our drilling is farmed out to a contracting company who drills them turnkey for us.

Technical issues

Other comments

Called on well in GOM Cameron to 19,000' depth TVD. Gas well, re-permitted.

Operator N



Merits & benefits of the insulated drill pipe system

Temperature is not a problem. 270 degrees F is the top temperature encountered in our wells out in the Gulf.

Technical issues

Other comments

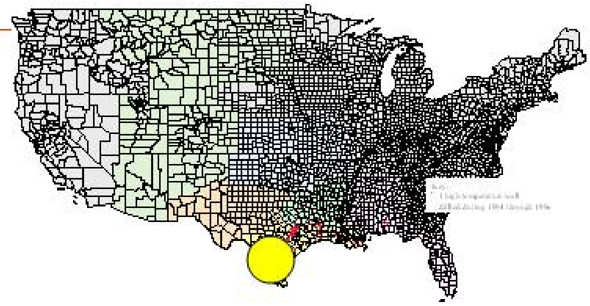
Called on well in GOM East Breaks 301 drilling to 25,000' TVD in 2000' water depth. Vertical oil well.

Operator P

Merits & benefits of the insulated drill pipe system

Our wells are in Hidalgo County, Texas and are 16,500' directional, development wells usually.

Temperature is not a problem.



Technical issues

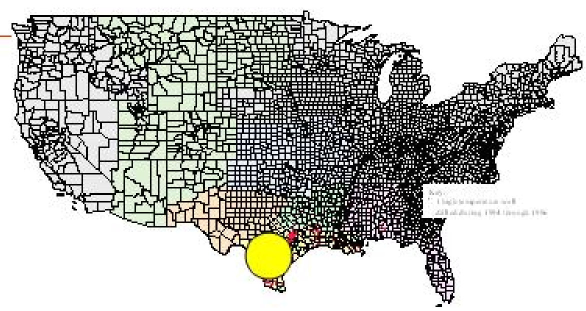
Other comments

Operator Q

Merits & benefits of the insulated drill pipe system

I'm familiar with Drill Cool and tried a short trial using a short section of insulated drill pipe. If my memory is right, the gain was from two degrees to five degrees improvement, with additional costs incurred, but marginal results realized.

The benefit from insulated drill pipe would be found in being able to make fewer trips to change out MWD and mud motors. There might be longer life for elastomers and seals. There could be savings in tool rentals as well as rig time for avoiding extra trips.



Technical issues

MWD stops at 303-305 degrees. High temperature does reduce tool life, shortens use of mud motors. After the MWD comes out, we use turbines to drill, but it is hard to keep a straight hole. The bit wanders.

If you could cool your mud to 303-305 degrees, or low enough to leave the MWD in the hole longer and reduce the number of trips for mud motors.

For these South Texas land wells we use both 5" and 4" drill pipe. Whatever Drill Cool brings out has to be useful in an oil based environment. And the insulation coating must be durable.

The smaller 4" drill pipe must be able to accommodate fishing tools.

Other comments

High temperature is a problem we have to deal with. Our wells frequently encounter bottomhole temperatures of more than 300 degrees F. Some wells have temps up to 435 degrees. We're in Zapata County, Texas drilling to 18,000', vertical, development wells.

Our wells in Zapata County were 17000 to 17700 foot depths, with no steerables in hole below 14000 feet. We made sure the rotary steering tools have been removed from the well at a temperature of about 300 to 303 degrees F.

I'd be happy to talk with Drill Cool when they come up with something that works. I (Jerry Hamilton) had worked with Tom Chamblis and another contact named Mark two or three years ago. Drill Cool had a piecemeal string of about 3 ½" but it was not enough to be much help.

Service Company Interviews

35

Service Company R

Merits & benefits of the insulated drill pipe system

I've heard about this California-based company and I know they provide mud cooling for several majors around the world.

I think insulated drill pipe is a good idea...we're going to need something to keep downhole electronics cool in these very deep, very hot Gulf of Mexico fields that have been discovered. MWD benefits from cooler mud.

But here is Drill Cool's challenge: Chevron's analysis shows that cooling the rock face in a deep, hot well creates massive amounts of formation damage, so they are actually thinking of heating the mud rather than cooling the mud.

Technical issues

Oil companies want a massive amount of data from the drilling process, so we are testing Grant Prideco's IntelliPipe. This is particularly true in deep, exotic wells that are most likely hot. My question is, can the insulated drill pipe ALSO carry a wire to transmit data?

In these deep wells, no matter how fast you circulate mud, you can only get a 5-10 degrees C improvement in your mud temperature...and that is not enough to matter because you are generally way over the 300 degrees F boundary.

I couldn't even hazard a guess how many true HT wells are drilled each year. It is probably measured in the dozens...that is the number I've heard quoted. It is not many. It would be more if we had the technology to do it, but I don't see that happening in my professional career. We've been working on HT tools for 20 years.

Other comments

Chevron is thinking of going to mud heaters, if you can believe that, in their deep Gulf of Mexico wells. They think that this may be the way to go, not cooling. Chevron and all the other majors will always prefer to reduce formation damage and sacrifice the electronics, not the other way around.

It was a big revelation when I heard Chevron detail their analysis. When you drill into deep, hot rock, you remove rock and the physical support. Then the effect of cooling reduces size, creating hoop stress, then the wall fails. They've confirmed this with micro-seismic and logs.

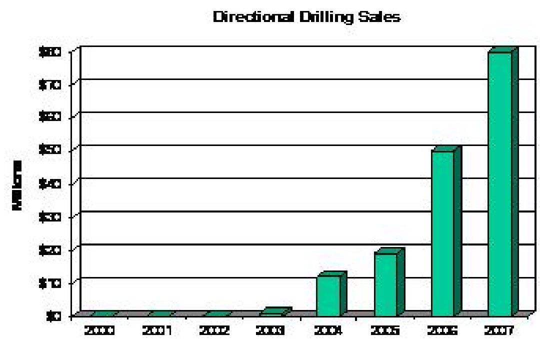
Baker and Halliburton and Schlumberger all have a small fleet of HT MWD with limited mission time capabilities and low reliability. They generally sit on the shelf because the wells they drill are critical, high cost and the tools are simply not reliable. The customer wants HT electronics that will work, but they will not pay more than 2x what they will pay for a standard tool.

Service Company S

Merits & benefits of the insulated drill pipe system

We are not involved with many hot holes in our segment of the business. Having said that, the only one that we participated in was an ECA well in Brazoria County south of Houston about 10 months ago which utilized this insulated drill pipe technology.

The drilling foreman in our office thinks that the premise of insulated pipe makes quite a bit of sense.



Technical issues

The diameters represented by the tool company (out of California, we think) would not allow the MWD tools to be run and ended up costing ECA about 15 days of rig time due to stuck tools and circulation issues.

Other comments

Service Company T

Merits & benefits of the insulated drill pipe system

I have not heard of Drill Cool's insulated drill pipe. Yes, the idea has merit. In the range of 200 degrees to 300 degrees there would be limited market potential, but in the range of lowering mud temperature from 400 degrees to 300 degrees, there would be much greater application.

With cooler mud you'd improve the life of elastomers, longer bit life, possibly better bit penetration due to cooler mud with more viscosity, less use of expensive mud additives, and more application of currently available tools rated to temperatures of cooled mud…below 300 degrees.

Technical issues

Stay in the range of plus or minus 10% larger or smaller than presently used pipe.

Drill Cool will want to contact John Hardin, Mechanical Engineer, Houston. Phone: 936 442-4845. He would probably be directly involved in this application.

NOTE: Spears tried to contact Mr. Hardin several times.

Other comments

Don't know how many wells this would effect. Most wells would be in the Gulf, and maybe most of those below 15000 feet TVD.

Drill Cool would want to market this to the directional drilling company.

Service Company U

Merits & benefits of the insulated drill pipe system

Yes, I know about Drill Cool's idea. I had previous contact with Drill Cool about five years ago.

I think the idea has merit, if applied right.

Benefits would be marginal at 200 degrees F, but if the temperature were to be 175 degrees C, there would be more application. There are more instruments with qualified electronics that could be applied at that temperature.

Technical issues

Needs to be close to diameters of existing drill strings.

The operator would not want to have a special string for the full length of hole. I'd agree with the other Halliburton engineer who suggested plus or minus 10% in diameters.

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Other comments

Hard to say how many wells could need this type drill pipe, but I think there would be more HT wells drilled if the technology were available to support more high temp drilling.

I could see it being used where you are encountering the high temperatures. Use would be application dependent, perhaps section by section. In the deep water of the Gulf of Mexico there possibly could be some cooling of mud by sea water.

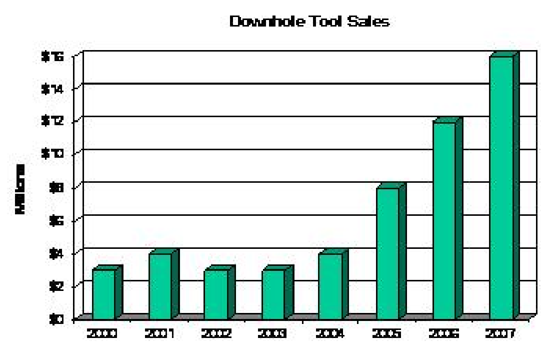
I don't know how you'd go to market, but the situation varies, but you'd need to work with both the directional company and the operator. It is partially dependent on who sources the pipe.

I've left Service Company U and started my own consulting company (Storm Energy).

Service Company V

Merits & benefits of the insulated drill pipe system

I don't know how many wells are drilled to greater than 300 degrees...land wells mostly top out around 300 degrees F.



Technical issues

Operators like to see the largest OD/ID drill pipe possible for their HT wells.

Any insulated drill pipe must stand up under a million pounds of shock force when the hammer is pulled on the jar.

Drilling engineers must be convinced that the insulated drill pipe can deliver the tension and the compression dynamics of an offshore well or a deviated land well.

Other comments

We rent and sell drilling jars into the HT market along the Gulf Coast and out in the Gulf of Mexico. We have about 25% of the Gulf offshore market and maybe 15% of the land, but it is the high end market along the coast.

We lose jars in 1-2% of the jobs we're on. We're run about 2000 jobs and we'll lose 20-30 jars a year.

HT wells all have sticking problems, so all operators use a jar to avoid fishing or to retrieve these million dollar MWDs.

Service Company W

Merits & benefits of the insulated drill pipe system

Yes, I have heard of Drill Cool's insulated drill pipe idea. It may have merit.

It could work to extend the life of tools, elastomers, and mud.

I imagine the greatest benefit would be in deep Gulf wells, and also in US onshore wells wherever high temperatures are encountered.

Technical issues

The insulated drill pipe would need to stay close to existing dimensions (of drill pipe commonly used). Drill Cool would not want to try much larger or smaller than what (the drilling engineers) are accustomed to using.

Other comments

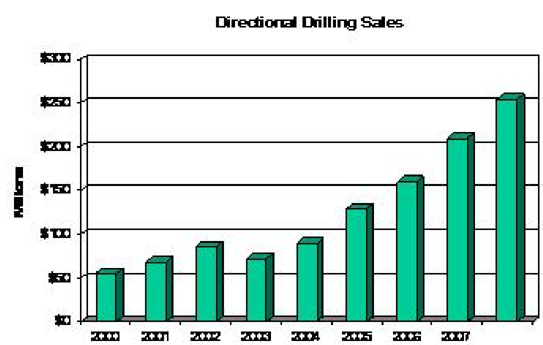
I really can't say how many HT wells are drilled in the US each year. I really don't know.

I think Drill Cool would need to do both (sell to the operators and market through the directional drillers), to familiarize operators with the benefits of the system and to give the directional drilling company maximum support that would help convince the operators to try it.

Service Company X

Merits & benefits of the insulated drill pipe system

We really don't touch the high temperature drilling. We can handle anything up to about 150 degrees C or 175 degrees C, but most our work is much cooler than that.



Technical issues

Other comments

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