METHOD FOR ELIMINATING WEAR FAILURES OF WELL CASING

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Field of Search 73/151; 166/254, 255; 175/40, 175/50

References Cited
UNITED STATES PATENTS
2,930,137 3/1960 Ards

3,130,785 4/1964 McCullough
3,399,723 9/1968 Stuart

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Attorney—J. H. McCarthy and T. E. Bieber

ABSTRACT

A method for eliminating wear failures of the casing of a well borehole adapted to be extended into a subterranean earth formation by determining where casing wear takes place, quantifying casing wear continuously, designing the casing for wear, reducing the amount of wear, and replacing casing worn to the tolerable limit.

28 Claims, No Drawings
METHOD FOR ELIMINATING WEAR FAILURES OF WELL CASING

BACKGROUND OF THE INVENTION

1. Field of the Invention

The invention relates to the installation and wear of well casings; and more particularly, to a method for eliminating wear failure of the casing of a well borehole adapted to be extended into a subterranean earth formation.

2. Description of the Prior Art

Casing wear is a serious problem in the drilling of well boreholes. A casing-wear hole may develop in less than 25 days or may not occur in a year. When casing wear is not quantified, casing-wear failures, unnecessary installation of inner strings, and unnecessary suspension of drilling can result. A blowout which includes a shallow casing-wear hole is one of the most dangerous situations encountered in a well.

Known prior art techniques for coping with such problems involve running caliper surveys or installing drill pipe rubbers. The caliper survey has the disadvantage that the survey itself causes wear, it is not known when to run the survey, and the results are questionable. Drill pipe rubbers have the disadvantage that it is not known where to install them; and the results are also questionable. In any event, the use of caliper surveys and drill pipe rubbers have not eliminated casing-wear failures.

SUMMARY OF THE INVENTION

It is an object of this invention to provide a method for eliminating casing-wear failure in a well borehole.

It is a further object of this invention to provide a method for determining the force-onto-the-wall of a well borehole caused by a tubing means extending therethrough.

It is a still further object of this invention to provide a method for quantifying wear of the casing of a well borehole caused by tubing means extending therethrough.

It is an even further object of this invention to provide a method for eliminating wear failure of casings of a well borehole.

These and other objects are preferably accomplished by determining where casing wear takes place, quantifying casing wear continuously, designing the casing for wear by increasing the physical properties of the casing, reducing the amount of wear, and replacing casing worn to the tolerable limit.

DESCRIPTION OF THE PREFERRED EMBODIMENT

It is well known in the petroleum industry that, in the art of drilling of a well borehole into a subterranean earth formation in search or production of minerals and/or energy, certain casing strings are needed. In offshore wells, caissons (drive pipe) are required; and in both offshore and onshore wells, conductor casing, surface casing, protective casing, protective casing liner strings and protective casing inner strings may be, or are, required under certain geological conditions as, for example, shown in U.S. Pat. No. 3,399,723. In all the aforementioned casing strings, by definition, formations are drilled below the casing. A casing string is sectionalized and is made up of interconnected sections, commonly referred to as joints, and the joints are generally in the range of either about 30 feet or 40 feet long. The joints are made up at upset collars or flush-joint couplings. When drilling is concluded and the minerals and/or energy are to be produced, casing to produce the well will be needed and such casing may be a production casing string, production casing liner, and a production casing inner string. Sometimes, a protective string may be used as a production string. In a given casing string, the outside diameter is generally constant. The grade (yield strength) is varied; and the wall thickness (or weight) is increased by reducing the inside diameter.

The purpose of casing and liner strings is quite rigid; and when the string fails to serve its intended function, the results are serious.

Techniques are well known for determining that the weights and/or grades of one interval are varied from another interval in a casing string to accommodate the variations in tensile load during and after installation, and the hydrostatic head of fluids inside and outside of the casing during drilling operations, including kick control, and added surface pressures during producing operations. A casing string to meet these requirements may be designed at minimal cost.

It is also well known that during drilling and completion operations, tubing means, such as tubing strings and wirelines, are run into the well borehole and through the casing strings. During drilling, the tubing means generally consists of a rock bit, drill collar, and drill pipe connected to a Kelly joint; and this string is commonly referred to as the drill stem. The drill pipe is also sectionalized and the length of each section, or joint, is about 30 feet. The coupling may be flush joint but is usually upset and called a tool joint. Rotation of the rock bit is required to drill, and this is generally accomplished by rotating the entire drill stem but may also be accomplished with the use of a motor above the bit. Trips are required to change worn-out bits and run logs or surveys. The surveys include electrical logs, density logs, sonic logs, directional logs, dipmeter logs, etc., all of which require wireline runs. During completion, cleanout trips, wireline runs, and installation of a tubing string are required. The tubing string usually has a constant inside diameter. All this movement involves rubbing metal against metal and induces wear. The movement is vigorous, and the wear is severe.

Studies have been made to determine the wear and fatigue to which the drill stem is subjected, and as aforementioned, techniques are well known to design a casing string with a safety factor for the tensile and pressure forces imposed upon it.

However, it is not known how to determine where, why, when, and how much wear occurs in a casing string; consequently, there are now no methods to (1) design a casing string for casing wear, (2) monitor and quantify casing wear continuously during operations, (3) reduce the amount of wear, (4) determine when casing has been worn to the tolerable limit, and (5) replace casing worn beyond the tolerable limit.

When used throughout this specification, the term "tubing means" will be used to refer to casing, liner, tubing, drill stem strings, and the strings used to drill and produce a well borehole such as the tubing string or wireline string.
In drilling a well, techniques are well known in the art of directionally surveying the trajectory of the well bore. Directional survey instruments used in practice measure the inclination of the hole with the vertical and the direction of the hole. The directional survey comprises a series of these measurements at pre-determined depths, and each depth of measurement is commonly called a station. The single-shot survey may be run while drilling and a multi-shot survey may be run while pulling out of the hole. Both of these surveys are made with the instrument seated in a non-magnetic drill collar. A directional survey may be run with an instrument attached to a wireline and lowered in the open hole. The direction in these instruments is obtained by a magnetic compass. A gyroscopic directional survey may be run on a wireline with the instrument inside a casing string. The original purpose of a directional survey was to compute the points-in-space of a well bore; however, in more recent years, the directional survey has been used to compute the hole curvature, also called dogleg severity or angle changes. For example, two stations A and B, may be used to establish the hole direction between them, and this direction may be extrapolated to the depth of station C. Stations B and C will establish another direction, and the angle change, or difference between the two directions may be computed manually using trigonometry. Manual calculations of dogleg severity are very tedious, repetitive, and time consuming and therefore are seldom done. This led to the development of nomographs, but the calculations are still tedious to make. More recently, dogleg severity calculations have been programmed for a computer. In one example, a computer output was taken of the dogleg severity of the surface hole, i.e., the hole to be cased with surface casing, in example well No. A. These computations are of the single-shot directional survey. It is common to refer to dogleg severity in degrees per 100 feet; however, hereinafter these angle changes will be computed in minutes per foot as a dogleg may exist in less than 100 feet. This output showed that angle changes were as high as 4.8 minutes per foot and as low as zero. These tests also showed that a high angle change was concentrated over a relatively short interval and that high angle changes were few in number. A high angle change covering a short interval may generally be reduced by string-reaming the dogleg. This, in effect, spreads the dogleg over a longer interval. String-reaming is accomplished by placing a roller bit, having the same gauge as the rockbit, at a point above the rockbit so that the desired weight will be in effect below the roller bit.

Casing wear is caused by the force of either the drill stem or wireline onto the casing wall and, with everything else being equal, is proportional to this force. This is expressed as Equation (1).

\[ V \text{Worn} = F \times CW \times D \]  

(1)

Where

- \( V \text{Worn} \) = Volume Worn;
- \( F \) = Force-onto-the-wall;
- \( CW \) = Coefficient-of-wear; and
- \( D \) = Duration or time of wear.

In turn, the main force-onto-the-wall is equal to twice the sine of one-half the angle change (dogleg severity) times the tension due to effective weight of the drill stem or wireline below the angle change. This is expressed as Equation (2).

\[ F = 2TS\sin(\theta/2) \]  

(2)

Where

- \( F \) = Force-onto-the-wall in pounds per foot;
- \( T \) = Tension of drill stem or wireline at angle change; and
- \( \theta \) = Angle change.

At very small angles, an equation of tension times either the sine of the angle change or the tangent of the angle change would approximate the answer; but the error increases as the angle change increases. The effective tension is the weight of the drill stem, or wireline, (in air) below the angle change calculated for the vertical component less the buoyancy factor of the fluid in the borehole. Tension is expressed as Equation (3) and buoyancy factor as Equation (4).

\[ T = (W_t \times V_{L2} + W_b \times V_{Lq} + W_z \times V_{Lg} \text{ etc})BF \]  

(3)

Where

- \( T \) = Tension in pounds;
- \( W_{t,0,5} \) = Weight per foot of each interval of drill stem in pounds;
- \( V_{L2,0,5} \) = Vertical length of each interval of drill stem in feet; and
- \( BF \) = Buoyancy Factor.

\[ BF = \frac{DENS - [0.12 \times \text{fluid weight}]}{DENS} \]  

(4)

Where

- \( BF \) = Buoyancy Factor;
- \( DENS \) = Density of metal of drill stem-grams/cc;
- 0.12 = Converts pounds per gallon to grams/cc; and
- Fluid weight is in pounds per gallon (ppg).

Tension is maximum at the surface and decreases to zero at bottom. Tension may be calculated at any projected depth either before the open hole is drilled or any depth during drilling operations. Therefore, with the tension and angle change known, the force-onto-the-wall may be calculated either before, when, or after the hole is drilled for a known angle change. Tension and force-onto-the-wall may be done manually, but again it is very tedious. A computer calculation was made of the tension and force-onto-the-wall at the doglegs of the surface hole of example well No. A with the proposed drill stem suspended to the projected total depth. The effective tension was found to be 154,480.1 pounds at the surface and 100,604.6 pounds at 4,064 feet. Also, the force-onto-the-wall was found to vary from 202.9 pounds per foot to zero. Five doglegs with forces-onto-the-wall of over 100 pounds per foot were found.

Casing wear will be concentrated in relatively few, isolated positions; these positions of casing wear exist where high angle changes and high tension coincide.

There is a component due to the unit weight of the drill stem that alters the tensional force-onto-the-wall. For example, in a hole slanted at 14 degrees from the vertical, a drill pipe having an effective weight of 16.6 pounds per foot would yield a force normal to a foot of casing of 4 pounds per foot. This would be added in angle drop-off and subtracted in angle build-up. Thus, it is seen that the force component due to the unit weight of the string may be taken into consideration.
but alters the tensional force-onto-the-wall only to a minor extent.

Significantly, the technique of force-onto-the-wall may be used to calculate the force-onto-the-wall of the borehole by the casing string itself. Thus, the technique of this invention may be used to properly centralize casing and prevent differentially stuck casing while running and cementing this string.

A directional well, by the fact it is deflected out to reach its target objective, must contain angle changes. The tendency is to make these deflections at shallow depths because the formations are softer and because, for a given slant, a greater horizontal distance may be obtained. As aforementioned, casing wear is greater at shallow depths for a given angle change. A vertical well is intended to be drilled straight and therefore, theoretically, there would be no angle changes or casing wear. However, as there is no such thing as a perfectly straight hole, angle changes exist in vertical holes to some degree. Generally, dogleg severity is greater in directional wells than vertical wells. Therefore, slant well boreholes with shallow angle changes are generally more susceptible to casing wear.

During drilling operations, the drill stem or wireline seeks a position on the casing wall due to the force-onto-the-wall and wears a groove. Viewing the longitudinal contact of the drill pipe on the casing, in 4½ inch extra-hole drill pipe having 6-inch OD tool joints, the radius of the tool joints would be three-fourths inch greater than the drill pipe. The sine (and tangent) of 15 minutes (one minute per foot) over a 15-foot distance (mid-point of a joint of drill pipe) amounts to about three-fourths inch. Therefore, the drill pipe comes to rest against the wall of casing with hole curvature in excess of 1 minute per foot. Thus, below that figure, all the wear may be attributable to the tool joints, while above one minute per foot, both would be expected to cause casing wear. As angle changes increase, wear due to the body of drill pipe increases. At high angle changes, most of the wear is due to the body of the drill pipe; and as aforementioned, generally casing wear is a problem where high angle changes exist and at shallow depths.

The volume of a groove in cubic inches per foot may be divided by 12 to obtain the cross-sectional area in square inches. The cross-sectional area of the casing-wear groove is crescent shaped. The drill stem crescent is formed by an arc of the inside of the casing and an arc of the outside circle of the drill stem. After the drill stem crescent is formed, a wireline crescent will be formed by the drill stem arc and arc of the outside circle of the wireline. In new casing, the wireline crescent will be formed by the casing and wireline arcs. Each chord of each arc are common to each other. When the chord of the wireline arc is equal to the diameter of the wireline, additional wireline wear will be plug-shaped. The area of all these crescents (and plugs) may be approximated by drafting them on grid paper and either (1) counting squares or (2) planimetering. This procedure is repetitive, tedious, and time consuming. Nomographs may be constructed for the crescent, but their use would still be tedious.

The area and dimensions of a crescent may be expressed in the following Equation (5):

\[ A = \frac{1}{2} \left( \sqrt{(2r_d + d)(2r_i + d)} - (r_i - r_d - d)^2 \right) \]

Where:
- \( A \) = Cross-sectional area of the crescent;
- \( r_i \) = Outside radius of either the drill stem or wireline;
- \( r_d \) = Inside radius of either the casing or outside radius of the drill stem; and
- \( d \) = Wall of casing that has been worn away, being the maximum thickness of the crescent.

Equation (6) is another equation that expresses the area and dimensions of a crescent:

\[ A = \frac{1}{2} \left( \frac{x_i - x_d}{r_d} \right) \left[ \frac{1}{2} + \frac{1}{2} \frac{1}{x_i - x_d} \left( \sqrt{r_i^2 - x_i^2} + x_i \right) \right] \]

Where:
- \( A \) = Cross-sectional area of the crescent;
- \( r_d \) = Outside radius of either the drill stem or wireline;
- \( r_i \) = Inside radius of either the casing or outside radius of the drill stem;
- \( x_i \) = Distance between centers of the two circles (the circles of \( r_i \) and \( r_d \));
- \( x_d \) = Distance between the chord (where it intersects the abscissa) and the center of the casing ID circle; and
- \( x_i - x_d - r_d \) = Wall of casing that has been worn away.

Calculations using either Equation (5) or Equation (6) are difficult to do manually. They may, however, be solved easily by a computer using the iteration method. When the radii are known, given the area "A," the wall worn away "d." (Equation 5) may be computed; and, vice versa, given "d," the area "A" may be computed. The area of the plug worn by the wireline after the chord of the crescent becomes equal to the diameter of the wireline may be expressed by the following Equation (7):

\[ ARPLG = DIAWL \times PWLP \]
Inches per foot of casing is required to wear a hole in the casing. This represents 59.2 percent more metal; and, all other parameters being equal, 59.2 percent more drilling time before failure occurs.

The coefficient-of-wear per unit of force may be obtained from a similar well borehole in which a casing hole has been worn. The wear factor may also be determined in a well borehole where a groove has been worn, the casing has been recovered, and a dimension of the crescent is measured. Laboratory tests may also be used to determine the coefficient-of-wear for field conditions. Thus, the coefficient-of-wear may be determined for either the drill stem or the wireline.

As discussed above wherein a computer calculation was made of the tension and force-onto-the-wall at the doglegs of the surface hole of example well No. A, any number of high forces-onto-the-wall may be selected by visual examination or by a computer. For example, a computer output of the five greatest forces-onto-the-wall and their interval may be taken. The initially designed casing string for tensile and pressure requirements will be known; and the joints of tensile-pressure designed casing string opposite the doglegs will also be known. Casing size is 13.5% inch in example well No. A. Using the aforementioned equations, the duration to failure may be determined either manually or by the computer. A computer output of the time-to-failure of the determined five greatest forces-onto-the-wall of example well No. A was found to vary from 27.7 to 44.9 days. It is recalled that the force-onto-the-wall in example well No. A is that for the drill stem suspended at the projected total depth. The actual drilling time will be higher as the weighted average force-onto-the-wall to drill the well will be less than that at total depth, but will be in relative proportion.

It was also found that the weakest interval was from 619 to 654 feet wherein the days-to-failure was 27.7. It was also noted that the casing weight opposite this interval was 54.5 pounds per foot and the wall thickness of 0.380 inch. Casing with a weight of 61.0 pounds per foot with a wall of 0.430 inch is in the casing string and may be placed in the interval 619 to 654 feet. Heavier casing with thicker wall is also available. Therefore, the casing string may be optimized with respect to weights. This may be done either manually or by the computer. In another example, the string was optimized by use of four weights. The time-to-failure was found to have increased from 27.7 to 42.9 days. This was accomplished by substituting heavier casing in four of the dogleg. Only five joints of casing were affected. The fifth dogleg, 3086 to 3120, was not affected by weight optimization.

There is a practical limit to increasing the wall thickness, i.e. weights, of casing, which reduces the inside diameter. Most factory-made weights are within a range to run a particular size rock bit (outside diameter). Further increase in weight would require drilling with a smaller rockbit, in which event, a smaller borehole would be drilled.

The tolerable limit of casing wear will be dictated by burst strength to contain pressures, primarily for kick control during drilling operations or surface pressures during producing operations. For example, a surface casing string may be intended to hold a back pressure of 2,000 psi to bring an expected kick under control, or a protective casing may be intended to hold 2,500 psi surface pressure during producing operations. In a hydropressure well, the surface casing string may be intended to hold only the pressure required to circulate the drilling fluid. Prudent operations would include a safety factor in such designs. The safety factor should be greater than tolerance of error of the coefficient of wear. When the casing reaches this state, it is spoken of as having reached its tolerable limit or as no longer safe for drilling.

Burst strength can be expressed by the following Equation (8):

\[
P_I = K \times 2.0 \times MYLST \times REWALL \times CASEOD
\]

Where:
- \(K\) = Coefficient;
- \(P_I\) = Remaining burst strength — psi;
- \(MYLST\) = Minimum yield strength — psi, or grade;
- \(REWALL\) = Remaining wall — inches; and
- \(CASEOD\) = Outside diameter of casing.

The following table shows some grades used in the petroleum industry as follows:

<table>
<thead>
<tr>
<th>Grade</th>
<th>Minimum Yield Strength (psi)</th>
<th>Ultimate Yield Strength (psi)</th>
<th>Minimum Brinell Hardness (bhn)</th>
<th>Minimum Rockwell Hardness (Re)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H-40</td>
<td>40,000</td>
<td>60,000</td>
<td>120</td>
<td>—</td>
</tr>
<tr>
<td>J-55</td>
<td>55,000</td>
<td>95,000</td>
<td>190</td>
<td>13.5</td>
</tr>
<tr>
<td>C-75</td>
<td>190</td>
<td>190</td>
<td>205</td>
<td>16</td>
</tr>
<tr>
<td>N-80</td>
<td>80,000</td>
<td>190</td>
<td>205</td>
<td>16</td>
</tr>
<tr>
<td>P-110</td>
<td>110,000</td>
<td>125,000</td>
<td>255</td>
<td>25</td>
</tr>
<tr>
<td>V-150</td>
<td>160,000</td>
<td>321</td>
<td>34</td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>55,000</td>
<td>95,000</td>
<td>190</td>
<td>13.5</td>
</tr>
<tr>
<td>E</td>
<td>75,000</td>
<td>100,000</td>
<td>205</td>
<td>16</td>
</tr>
<tr>
<td>G</td>
<td>105,000</td>
<td>120,000</td>
<td>245</td>
<td>24.0</td>
</tr>
<tr>
<td>S</td>
<td>135,000</td>
<td>150,000</td>
<td>302</td>
<td>32</td>
</tr>
<tr>
<td>X-95</td>
<td>95,000</td>
<td>110,000</td>
<td>229</td>
<td>20.5</td>
</tr>
</tbody>
</table>

In a given casing size where the tolerable limit is a fixed burst strength, it is seen that the required remaining wall may be reduced by increasing the minimum yield strength. This means more volume of casing may be worn before the tolerable limit is reached.

In addition, Table A shows that Brinell hardness correlates with ultimate strength. Ultimate strength correlates with minimum yield strength, or grade. Therefore, by increasing grade, Brinell hardness is increased and the coefficient-of-wear is decreased. Optimization of a casing string by grade may be done manually but, again, it is quite tedious. In another example, the casing string of example well No. A was optimized by both four weights and two grades. The second grade had a coefficient-of-wear that was 30 percent less than the first grade. There was found to be 27 different combinations of a stronger casing string. Also, the use of four weights and two grades was found to have increased the time-to-failure from 27.7 to 61.3 days, or 121.3 percent.

A casing string is no stronger than its weakest interval. After progressively upgrading each interval, but only to extent that it does not remain the weakest interval, it was found that eventually a state was reached wherein one interval can no longer be upgraded.
As aforementioned, the foregoing example computations are those for the single-shot directional survey. A directional well may be either a "L" type or "S" type. The "L" type is accomplished by deflecting the well bore to the desired slant and maintaining the slant to total depth. The "S" type is accomplished by deflecting the well bore to a desired slant, maintaining the slant until the desired horizontal distance is reached, and then the well bore is permitted to return to vertical. Thus, both types contain the first bend, and the "S" type contains a second bend. The top of the first bend is commonly called the kick off point (KOP). The first bend may be accomplished by either (1) a down-hole motor with a bent sub, (2) a jet bit, or (3) a whippstock. The angle changes may generally be kept to lower values with the down-hole motor assembly, followed by the jet bit, and are generally higher with the whippstock. On the other hand, the formations may be such that the desired deflection cannot be obtained by the down-hole motor assembly, followed by the jet bit, and the whippstock is then required. Thus, steps can sometimes be taken to keep angle changes to lower values in the first bend.

Some up-the-hole doglegs will be partially wiped out automatically during drilling. As aforementioned, other doglegs may be reduced by string-reaming the interval which, in effect, spreads the angle change over a longer interval. It is common practice to place the KOP just below a casing shoe. This precedes spreading the angle changes of this bend. Therefore, it is part of this invention that the KOP be placed a sufficient distance below the last casing shoe so that formations will exist above as well as below the KOP to permit string reaming. Therefore, before casing is installed, angle changes may be (1) kept to relative low values and (2) may be reduced. Equations (1) and (2) show that the reduction of the angle changes reduces the force-onto-wall. This, in turn, reduces the amount of wear, which increases the allowed drilling time. As aforementioned, a multi-shot, wireline, or gyroscopic directional survey may be run before the casing is installed, and, where high dogleg severity and high forces-onto-the-wall exist, the directional survey may be run at 30-foot stations, when necessary, to obtain the accurate dogleg severity conditions in the well borehole. Again, dogleg severity, force-onto-the-wall, days-to-failure of the originally designed casing string, and the optimized casing string by weights and grades, all may be determined.

The positions where wear will be concentrated is generally in that part of the string where the thinnest wall and lowest grade are required for pressure-tensile requirements. A string of thick wall and high grade throughout increases the cost of the string quite substantially and will require an addition to the tensile requirements. The extra cost to optimize a casing string is nominal.

Tension of the drill stem may also be decreased by decreasing the weight of the drill stem. Equations (1) and (2) show that the reduction of tension reduces the amount of wear. The weight of the drill stem may be reduced by tapering the drill pipe. For example, 4 ½-inch, 16.6 pound per foot, may be used in the upper part of the string and 3 ½-inch, 13.3 pound per foot in the lower part of the string. Another way to reduce tension is to substitute a drill stem composed of a metal lighter than steel. For example, aluminum drill pipe may be used. The body of the drill pipe is aluminum-steel whereas the tool joints are steel. Some of the aluminum physical difference with steel, and some aluminum drill pipe physical dimensions and properties, are tabulated in Table B.

### TABLE B

<table>
<thead>
<tr>
<th>Aluminum-Alloy</th>
<th>Steel</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nominal</strong></td>
<td><strong>Body</strong></td>
</tr>
<tr>
<td>OD</td>
<td>OD</td>
</tr>
<tr>
<td>4 ½-in.</td>
<td>5.031</td>
</tr>
<tr>
<td>4-in.</td>
<td>4.625</td>
</tr>
<tr>
<td>3 ½-in.</td>
<td>3.875</td>
</tr>
<tr>
<td>3-in.</td>
<td>3.35</td>
</tr>
</tbody>
</table>

From Table B, it is seen that 4 ½-in. OD, 3.6-in. ID aluminum-alloy drill pipe weighs 10.75 pounds per foot whereas 4 ½-in. OD, 3.64-in. ID, steel drill pipe weights 20.0 pounds per foot. In addition, it will be noted the effective density of aluminum drill pipe ranges from 3.156 to 3.324 grams per cubic centimeter as compared to 7.85 for steel. Therefore, as shown in Equation (3) and Equation (4), a decrease in density decreases the buoyancy factor which decreases the tension. For example, a 4 ½-in. OD string of steel drill pipe weighing 100,000 pounds in air will weigh 75,541 pounds in a 16-ppg mud; whereas, a 4 ½-in. OD string of aluminum drill pipe also weighing 100,000 pounds in air will weigh 40,832 pounds in 16-ppg mud. Thus, drilling time before the tolerable limit is reached may almost be doubled by using aluminum drill pipe instead of steel drill pipe.

Drilling time may also be increased by using a larger drill pipe down through the weakest dogleg. As discussed above, an increase in the drill pipe diameter increases the volume of casing required to wear a hole in the casing. In addition, aluminum and steel are dissimilar metals and when rubbed against each other, they provide a "bearing" surface. This same bearing effect is accomplished by either (1) galvanizing (hot dip) or (2) electroplating either the inside wall of the casing string or outside wall of the drill pipe.

As discussed in U.S. Pat. No. 3,399,723, a fluid medium is needed to drill. This fluid may be gas, either air or hydrocarbon gas, in "hardrock" country, or a liquid in both "hardrock" and "soft-rock" country. Lubricants may be added to the drilling fluid medium which in turn reduces the coefficient-of-wear of the drill stem and casing. These lubricants include graphite, asphalt, crude oil, refined oil, walnut shells, etc. The lubricity is increased substantially when water-base muds are replaced with oil-base muds.
Some materials in the drilling fluid increase the coefficient-of-wear. Those that are harmful and are normally added to the drilling fluid may be either left out or replaced by additives that are not harmful.

Some materials that increase wear are picked up during drilling. Sand, for example silica sand, when added to the drilling fluid increases wear substantially. In a mud, the sand may be recirculated; but this problem is reduced when steps are taken to de-sand the mud.

Corrosive materials may be added or picked up while drilling, but steps may be taken to neutralize such corrosion. For example, carbon dioxide may exist in the pore fluids of the formations and enter into the drilling fluid. The carbon dioxide combines with water to form carbonic acid which is corrosive and increases wear. Additions may be made to neutralize this acid into harmless residues.

All the aforementioned tests may be taken in accordance with my invention before drilling is undertaken below the casing and/or liner.

While drilling is undertaken below a casing and/or liner string, the casing wall opposite one or a selected number of doglegs may be monitored continuously or periodically for casing wear. For example, the volume of wear may be accumulated; and the wall worn away, remaining wall, and remaining burst strength may be calculated each day. The calculations may be broken down for either wireline and drill stem operations. For example, the cumulative volume of wear and cumulative wall worn away for drill stem operations may be obtained. The wear for a subsequent wireline operation may be calculated, and the wall worn away may also be computed. Thus, the remaining wall of the wireline groove inside the drill stem groove may be obtained, and the burst strength computed.

The volume of the wireline groove must be taken into consideration when drill stem operations are resumed. Until the wireline groove is "wiped out" by the drill stem, the remaining wall will be due to the wireline groove and remains the same. After the drill stem groove wipes out the wireline groove, additional wear by the drill stem will determine the remaining wall. Most formation-evaluation logs, e.g., the electrical survey, must be run in open hole; however, it would be possible to defer all wireline surveys until the open hole has been drilled and just before it is to be cased (or abandoned). In this event, only the drill stem groove would be involved in casing wear.

When the tolerable limit of the casing and/or liner is reached, drilling and/or wireline operations may be suspended; but steps may be undertaken, as hereinafter described, to permit additional operations.

In all probabilities, the first tolerable limit of casing wear will be reached at a relative shallow interval in either surface casing or protective casing, but the following steps are not restricted to these two casing strings.

If no additional drilling is permissible with surface casing, a protective casing string may then be installed. This installation automatically leads us to the following:

When the tolerable limit of wear of the protective casing is reached, an inner casing string may be installed. It is understood that all casing and/or liner strings are to be optimized as was discussed hereinabove. It is recalled that the amount of wear that will occur may be computed before the casing and/or liners are installed and the number of days to failure may be calculated for an estimated weighted average tension. The number of days required to drill to the target objective may also be estimated. Therefore, it may be ascertained whether or not any casing string and/or liner will be adequate for the required operations.

It is common practice to cement surface casing, protective casing, and protective liners in well boreholes. Liners are generally cemented throughout. The surface and protective casing may sometimes be recovered by backing it off or cutting it in two in the borehole; but generally such a recovery may only be accomplished by that amount of protective casing inside the surface casing and that amount of surface casing inside the conductor string. However, such steps may not be possible except when the well is abandoned.

It is common practice to cement inner strings. It is recalled that an inner string is, by definition, a casing string installed inside another casing string. It is a part of this invention that inner casing strings be installed in order that they may be recovered when desired. Thus, when an inner casing string reaches the tolerable limit, it may be replaced with a new inner casing string. This may be repeated indefinitely. Therefore, casing wear may be eliminated as a limitation in drilling operations.

The bottom of the inner string requires a rigid seat such that a joint or joints will not back-off during drilling. This may be accomplished by a recoverable packer. The bottom of the inner string may also be attached by a permanent packer or may be cemented. In this event, a back-off coupling is provided above the packer or cemented zone. Centralization may be provided above and below the coupling to facilitate backing-off the old inner string and stabbing the new inner string.

The tolerable limit of casing wear may be reached by either the drill stem groove and/or wireline groove, and additional wireline operations are desired. In this event, either an open-ended drill pipe string, open-ended casing string, or open-ended tubing string may be run through worn spots of the casing string, and the wireline operations continued without limitation. The wireline wear then occurs in the open string, and the casing string is protected. The open-ended string may be re-oriented a few degrees of a circle periodically and wireline wear will not be concentrated in one groove in the string.

The drill pipe opposite the angle changes may be equipped with stabilizers. The stabilizer designed for casing wear would be one which the inside is stationary against the drill pipe and outside is stationary against the casing, with the rotation occurring inside the stabilizer. The stabilizer may be a prepac lubricated, sealed, roller-bearing. The stabilizer may also be designed with a lubricated bearing of two dissimilar metals, such as the main bearing of an automobile engine. With such a "bearing" stabilizer, there is neither rubbing of drill stem against the casing nor rubbing of stabilizer against drill stem, nor rubbing of stabilizer against the casing, as all movement will occur in the bearing of the stabilizer.

In accordance with my invention, the aforementioned stabilizers should be placed opposite the intervals where casing wear will be concentrated as discussed above. Further, two stabilizers are placed on
each joint, one at the tool joint and one at the middle of the joint of drill pipe, opposite the intervals of critical wear. Corrugation of the stabilizer improves its efficiency.

As discussed before, casing wear is broken down into that caused by the drill stem and that caused by wireline operations. The components of drill stem operations may also be subdivided. For example, drill stem operations may be broken down into the time of: rotation for drilling, rotation to condition mud, trips, fishing, and no drill stem operation. The drill stem operations of wells in a geological environment with a drilling routine are similar with one another. Therefore, using day's operations normalizes these components, and the wear calculated for one well will agree closely with another well.

If the drilling routine is different, the operations may be broken into the additional components. The rotary speed (revolutions per minute) may be taken into account during drilling, and time can be accumulated in rpm-hours-force. The drill collar weight is designed for weight-on-bit, and the weight-on-bit may be deducted from the drill stem weight while drilling. When mud is conditioned, the rotary speed is reduced, but the full weight of the drill collars are added to the drill pipe string. During a trip, the weight of the drill pipe string includes the drill collars when starting out of the hole and reaches zero at the surface, and this weight is reversed when the drill stem is run into the hole. Trip movement is longitudinal as compared to rotation for drilling. Wear is different when fishing: working the drill stem involves adding to and slacking off the full weight of the drill stem. Again, these component calculations may be done manually but preferably are carried out by a computer.

It is recognized that there are many factors to well casing wear. For example, the hard-facing of tool joints may be expected to increase the coefficient-of-wear of casing. Here, the objective is the protection of the drill stem, and more particularly, the tool joints.

Drill pipe rubbers have been installed on the drill pipe of the drill stem. The results of such installation are questionable. Installation is made at the tool joints on each joint, every other joint, every third joint (three, or stand) through all or most of the casing string. Thus, drill pipe rubbers are used primarily for the protection of the tool joints. As aforementioned, casing wear at high angle changes is caused by the body of the drill pipe. Former drill pipe rubbers were susceptible to impregnation by gas, and very large swelling sometimes resulted when the rubber was pulled out of the hole. In fact, recovery of the drill stem to eliminate swelled drill pipe rubbers was a difficult operation. While rubbers are now available that are impervious to gas swelling, there is the possibility that sand becomes impregnated in the rubber causing more wear than the drill pipe body. There has always been the problem of drill pipe rubbers being torn loose. In any event, the use of drill pipe rubbers has not solved the problem of casing-wear failures.

If drill pipe rubbers are found to reduce the wear of the casing by the drill stem, placement of the rubbers would be similar to the placement of the aforementioned stabilizers at the center and end of each joint opposite the intervals where wear will be concentrated.

SUMMARY OF METHODS FOR ELIMINATING CASING-WEAR FAILURES

I. Intervals along the well borehole where wear will be concentrated are first determined and reduced, as discussed hereinabove and summarized below:

1. The angle changes in a well borehole may be held within acceptable limits while drilling the well borehole. A slant well borehole may be deflected out to the desired horizontal distance with angle changes still held within acceptable limits, with preference given to a down-hole motor assembly, then a jet bit, and finally a whipstock to deflect the borehole. The kick-off point (KOP) may be selected so that formations exist above and below. A directional survey of the well borehole may be made while drilling to determine the magnitude and depth interval in the well borehole of angle changes (dogleg severity).

2. The force-onto-the-wall by the drill stem may be computed for each dogleg using the tension of the drill stem projected to both (a) the target objective, (b) its estimated weighted average to reach the target objective, or (c) any depth above the target objective. The force-onto-the-wall may be calculated by a mathematical equation.

3. The wall of the well borehole may be string-reamed at high angle changes, if necessary, to reduce them by distributing them over a longer distance. This may include the first bend as formations will exist above and below.

4. Portions of the hole, if necessary, may be directionally surveyed again and dogleg severity calculated again. The high doglegs, particularly those causing the high forces-onto-the-wall or those over a long interval, may be resurveyed at 30-foot stations.

5. Steps I.3 and/or I.4 may be repeated until the reduction of angle changes is optimum and the high angle changes are accurately determined within 30-foot stations.

6. Step I.2 may be repeated. Intervals where force-onto-the-wall of the drill stem is abnormally high and casing wear will be concentrated may be determined.

7. The following mathematical equation may be used to calculate to force of drill stem onto-the-wall for Step I.2, hereinabove. Force equals the product of twice the sine of one-half the angle change times the tension at the angle change.

8. The days to failure can be determined for the tensile-pressure designed casing string.
    a. The mathematical formula for a crescent is used in calculating days-to-failure.

II. The tensile-pressure designed casing or liner string may be also designed for casing wear by strengthening those intervals where wear will be concentrated. This may be accomplished by:

1. Installing thicker-walled casing in those intervals where wear will be concentrated as determined in Step I.6.

2. Installing higher grade casing in those intervals where wear will be concentrated as determined in Step I.6. Grade reduces the coefficient-of-wear and permits more steel to be worn before the tolerable limit is reached.
3. Optimizing the casing string for wear with the weights and grades available in the string at the rig site.
4. Optimizing the casing string for wear with the weights and grades available from the steel-mill factory.
5. Calculating the projected time that casing will be worn to where it is no longer safe (tolerable limit is reached).
6. Monitoring continuously casing wear so that the remaining wall and burst strength will be known at all times.
   a. The remaining wall may be calculated with mathematical formula of the crescent. The burst strength may also be calculated with a mathematical formula.
7. Suspending drilling before the casing fails.
8. Installing an inner string if additional drilling is needed to reach the target objective, designed for casing wear in the same manner as the casing and liner string.
9. Installing an inner string if needed to hold high surface pressures to produce minerals and/or energy.

III. The rate of wear of the casing string may be reduced in the following manner:
1. A tapered drill stem may be installed that reduces tension and force-onto-the-wall, which in turn reduces the amount of wear.
2. A drill stem may be installed which is composed of a metal with less density than steel and which reduces tension and force-onto-the-wall. The reduction of the force-onto-the-wall reduces the amount of wear.
3. A drill stem with a larger-diameter drill pipe body may be installed opposite the intervals where wear will be concentrated. The larger-diameter drill pipe body will require wearing of more volume of casing steel before the tolerable limit is reached.
4. The lubricity of the drilling fluid may be increased.
5. The abrasiveness of the drilling fluid may be decreased by removal of deleterious solids.
6. The corrosiveness of the drilling fluid may be decreased.
7. Stabilizers may be installed on the drill stem opposite those intervals where casing wear will be concentrated.
   a. Two stabilizers may be installed on each joint, one at the tool joint and one mid-way between tool joints, opposite the intervals where wear will be concentrated.
   b. The inside of the stabilizers may be fixed to the drill stem and outside remain stationary on the casing wall with the rotation occurring in a "55 bearing" within the stabilizer.
   c. The bearing may be pre-packed and lubricated.
   d. The bearing may be a roller-bearing.
   e. The stabilizer may be corrugated.
   f. The stabilizer may be an improved adaptation of the drill pipe rubber.
8. Either the inside of the casing or the outside of the drill stem may be either galvanized or electroplated.

IV. Retrievable inner tubular strings (either inner drill pipe, inner tubing, or inner casing strings) may be installed:
1. A retrievable inner casing string may be installed with the bottom at least below the critical intervals found in either Step I.2 or Step I.6 down to the liner casing top. The bottom of inner casing may be affixed rigidly to the outer casing string such that drilling can be conducted. The bottom attachment may be accomplished by a retrievable packer which will permit recovery. The bottom may also be attached by either a permanent packer or by cementation, and a special coupling may be provided at a predetermined depth but at least below the critical intervals. The inner string will be retrievable and replaceable to the coupling. Centralization of the coupling will facilitate stabbing the replacement string.

   The retrievable casing string may be replaced before casing is unsafe as determined in II.6, or if needed for high surface-pressured well boreholes. Replacement can be repeated over and over again, as required.
2. A retrievable inner tubular string may be run past the critical intervals when surveys are run on wirelines. Wireline wear then occurs on the inner tubular string and not on the casing string.
   a. The inner string may be used for wireline work when the casing is no longer safe for drilling as determined in Step II.6, hereinabove.
   b. The orientation of the inner string may be changed so that the positions of grooves of wear within the inside circumference are changed as desired.

V. The coefficient-of-wear used in Step I.8 and Step II.6 may be adjusted for greater accuracy by acquiring a dimension of the crescent as follows:
1. A hole may have been worn in the casing in a well not drilled with these techniques. The wall worn away then equals the wall thickness.
2. Casing is recovered and a dimension of the groove is measured.
3. An improved caliper survey is run and provides a dimension of the crescent.
4. A down-hole televiwer is run and provides a dimension of the crescent.

I claim as my invention:
1. A method of determining the force-onto-the-wall by tubing means adapted to be extended down a well borehole adapted to be extended into a subterranean earth formation comprising the steps of:
   a. Drilling a well borehole into said formation; directionally surveying where angle changes take place in said well bore;
   b. Determining the magnitude of the angle changes; installing a tubing means in the well borehole;
   c. Determining the tension of the tubing means at the angle changes; and
   d. Determining the force-onto-the-wall at the angle changes by said tubing means using the predetermined tension and magnitude of the angle changes.
2. A method of quantifying wear of first tubing means, extended into a subterranean earth formation, by a second tubing means adapted to be extended down said first tubing means, said method comprising the steps of:
   a. Drilling a well borehole into said formation; directionally surveying where angle changes take place in said well bore;
determining the magnitude of the angle changes within said well borehole;
installing said first tubing means in said well borehole in fixed relationship thereto;
drilling below said first tubing means in said well borehole;
extending said second tubing string down said first tubing string;
determining the tension of the second tubing means at the predetermined angle changes in said well borehole;
determining, via the predetermined tension and magnitude of angle changes the force-onto-the-wall of the first tubing means by the first tubing means;
quantifying the amount of first tubing means wear in the interval of each angle change using force-onto-the-wall, coefficient-of-wear, and time; and
accumulating the amount of wear and wall worn away of the first tubing means casing while undertaking operations in said well borehole below said first tubing means.

3. A method for eliminating wear failure of first tubing means adapted to be extended into a subterranean earth formation, a second tubing means adapted to be extended down into said first tubing means after said first tubing means is installed in said well borehole, said method comprising the steps of:
drilling a well borehole that is to be cased;
directionally surveying where angle changes take place in said well borehole;
determining the magnitude of each angle change between at least two survey stations;
installing said first tubing means in said well borehole in fixed relationship thereto;
drilling below said well borehole into said formation;
extending said second tubing means down said first tubing means;
determining the tension of the second tubing means at said angle changes;
determining via the predetermined tension and magnitude of angle changes the force-onto-the-wall of the first tubing means by the second tubing means, thereby determining intervals where first tubing means wear will be concentrated;
quantifying the amount of first tubing means wear at each angle change via the predetermined force-onto-the-wall, coefficient of wear, and time;
accumulating the amount of wear and wall worn away of the first tubing means while undertaking operations below it; and
suspending operations when the tolerable limit of the first tubing means is reached.

4. The method of claim 3 including the step of determining the day-to-failure of the first tubing means for a given projected tension of the second tubing means prior to drilling the borehole, thereby determining where first tubing means wear will be concentrated and thereby determining the time when the tolerable limit will be reached.

5. The method of claim 3 including the step of running a reaming means down said well borehole prior to installing said first tubing means therein; and reaming via said reaming means, said well borehole at a plurality of said intervals where wear will be concentrated and where high angle changes exist to thereby reduce the magnitude of said angle changes.

6. The method of claim 3 wherein the step of determining the force-onto-the-wall of said first tubing means by the second tubing means includes the step of determining the force-onto-the-wall by taking the product of twice times the sine of one-half the angle change of said well borehole times the tension of said angle change.

7. The method of claim 3 wherein the step of installing the first tubing means includes the step of providing first tubing means having a wall with a thickness, adjacent to at least some of said intervals where wear will be concentrated, greater than the thickness of the wall of the first tubing means either just above or below said interval.

8. The method of claim 3 wherein the step of installing the first tubing means includes the step of optimizing the first tubing means for wear with respect to wall thickness by placing joints of greater wall thickness opposite the intervals where wear will be concentrated and are involved in the optimization.

9. The method of claim 3 wherein the step of installing the first tubing means includes the step of providing said first tubing means with a wall having a higher grade of material, adjacent to at least some of said intervals where wear will be concentrated, than the grade of material of the wall of the casing string either just above or below said interval.

10. The method of claim 3 including the steps of:
extending said second tubing means down said well borehole within said first tubing means; and
providing stabilizers on said second tubing means that are selectively spaced therealong so as to be adjacent to said intervals where wear will be concentrated in said well borehole and are adapted to stabilize the force of said second tubing means on the wall of said first tubing means.

11. The method of claim 3 and in addition deflecting said borehole to reach a target, the point at which said borehole is deflected being located a sufficient distance below the last casing shoe to permit reducing the angle of change of the borehole by string reaming.

12. The method of claim 3 and in addition optimizing the installation of the first tubing means by placing joints of higher grade opposite the intervals where wear is concentrated.

13. The method of claim 3 and in addition installing an inner tubing means as a substitute for said first tubing means at intervals where wear is concentrated.

14. The method of claim 13 wherein said inner tubing means is retrievable.

15. The method of claim 3 wherein the wear on the first tubing means is reduced by using a metal less dense than steel for forming said second tubing means.

16. The method of claim 3 wherein said second tubing means comprises a wire line and the wear on the first tubing means is eliminated by installing a third tubing means in the borehole prior to running said wire line in the borehole.

17. The method of claim 3, and in addition optimizing the installation of the first tubing means by installing tubing means having increased physical properties opposite intervals where wear is concentrated.

18. The method of claim 3 wherein the volume of the first tubing means worn away is quantified by mathematically calculating the area of the crescent worn in the first tubing string.
19. The method of claim 3 wherein the wear on the first tubing means is reduced by reducing the load of the second tubing means on the first.

20. The method of claim 3 wherein the borehole is directionally surveyed at substantially 30 ft. intervals where angle changes occur.

21. The method of claim 3 wherein said second tubing means comprises a drill string having two stabilizers disposed on each joint of drill pipe, said stabilizers being positioned at intervals where casing wear will be concentrated, one of said stabilizers on each joint of pipe being disposed at the middle of the joint, the other stabilizer being disposed at the end of the joint.

22. The method of claim 21 wherein said stabilizers include an internal bearing.

23. The method of claim 3 wherein the wear on the first tubing means is reduced by reducing the coefficient of wear.

24. The method of claim 23 wherein the coefficient of wear is reduced by using a second tubing means having a plated outer surface adjacent the intervals of wear.

25. The method of claim 23 wherein the coefficient of wear is reduced by using a second tubing means having a relatively large diameter adjacent the intervals of wear.

26. The method of claim 2 wherein the burst strength of the remaining first tubing means is determined.

27. The method of claim 23 wherein the coefficient of wear is reduced by increasing the lubricity of the drilling fluid.

28. The method of claim 3 wherein the coefficient of wear is adjusted by obtaining physical data relating to the wear of the casing string.

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