Reverse method for determination of the qualitative wear occurring in the intermediate casing installed in oil and gas wells

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Abstract. The aim of the present paper is to set up a method for enhancing the casing design with emphases on the intermediate casing or liners, regarding the wear of the casing wall, which is appearing while drilling the subsequent horizontal production hole. By using this method, the well designer has the opportunity to prepare a “working envelope” in such a way that the further considerations as the well trajectory, dog leg severities, drilling parameters, type of mud, tool join geometry, should keep the casing wear in within technological limits imposed by the oil and gas operator, in order to maintain the intermediate casing (liner) integrity and do not diminish or affect at least the upcoming well stimulation programs, and well control measures. More than this, by using this method, the well trajectory can be optimized from the begging in such a way that the lateral forces on tool joints to be full as per recommendations of API RP7G [1], so increasing the safe work of the drilling string bellow the fatigue stress limits.

Keywords: intermediate casing, oil, gas, drilling, liner, well.

1. Introduction

The casing program is the core for any well design. In complex high-profile wells, as extended reach, long horizontal 2D and 3D even slant, S or J profile, having a big step out, if these wells are to be drilled in deep water, H₂S/CO₂, HPHT environment, then the integrity of the intermediate casing/liners covering the curved portions of the hole with high dog leg severities, is becoming a paramount.

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It is well known and demonstrated by practice that the intermediate casing or liners having the shoe set at the top of pay zone, should keep their integrity in full, for the body and at the connections level, in such a way that the well control measures should not be affected, the upcoming well stimulation programs should not be downgraded, and the tools, devices, equipment required inside of this casing should be installed and operated in proper conditions. In other words, the intermediate casing/liners should keep the burst and collapse pressure as rated in their technical specifications.

Unfortunately, drilling the subsequent sections will affect more or less the above conditions. Casing wear is a very known phenomenon which has direct and indirect causes.

As direct causes [2]:
- Wellbore Dog Leg Severity;
- Casing internal diameter and external diameter of drill string/tool joint;
- The nature of casing and drill string surface;
- Lateral forces on tool joints, time exposure while rotating and penetrating inside casing;
- Casing wear coefficient.

As indirect factors:
- Annulus dimensions;
- Flow rate;
- Drilling fluid type;
- Temperature;
- pH value;
- Sand content.

Studies and experiments have shown that if the depth of wear in the casing wall is 10% of the wall thickness, then the burst pressure will drop at 90% of its original value and for a wall loss of 20% the collapse pressure is dropping to 80% of its original value [2]. Therefore, even the casing wear calculation is not standardized in industry, oil and gas operators are limiting the casing wear in between 4 - 6% as technologic limits [3].

In order to meet this requirement, the well designer should perform in advance casing wear simulation to see how the well trajectory (DLS – Dog Leg Severity), drilling parameters, type of drilling fluid, type of tool joints, time of exposure will affect the casing wear in such a way, that if the casing wear cannot be maintained under the technological limits, then some lengths should be reconsidered by changing the wall thickness.

2. The concept and method of calculation

The "Reverse" method is based on the hypothesis that during drilling with any bit diameter, having any intermediate casing diameter already set in place, using any type of special connections for the drilling string, the lateral forces shall be
developed on the respective connections, covering a large spectrum of forces on tool joints, according to the API RP7 G diagram in figure 1 [1].

Fig. 1. Lateral Force on tool joint [1]

In order to use this method, the following sequence of rationales should be applied:  
**a.** Choose the sequence of intermediate casing that are intended to be run and will cover or is covering the area of buildup / drop down inclination and /or turning to the target azimuth.  
**b.** Choose the sequence of drilling pipe with the connections proposed for use or which are used and rotated in the intermediate casing during drilling in the horizontal or subsequent deviated section.  
**c.** All data are gathered as in the table 1.
Table 1. Sequence of casing, drill pipe and tool joints proposed for study

<table>
<thead>
<tr>
<th>Intermediate casing</th>
<th>Drill pipe inside Casings</th>
<th>Drill pipe Tool joints</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dc, Dp, L, Dx, Sr</td>
<td>Pp, Vp, Hp, Ip, Ex</td>
<td>3</td>
</tr>
</tbody>
</table>

- 1000 m horizontal drilling right after intermediate casing;
- Motor drilling / 60 rpm at surface (RPM);
- 4.2 m / hour - penetration rate (ROP);
- Average wear factor (FF) 5.6-10 psi-1 corresponding for metal connections smooth [3].

As a mathematical model, the following theories, assumption and equations shall be used:

As per White and Dawson (1986), Archard (1953) casing wear caused on the inner surface of a casing string by the rotating tool joints of the drilling string is induced by the adhesive wear and depends mainly by the contact load between tool joint and casing surface, the hardness of the surface being worn away, the contact length between the two surfaces, and a wear coefficient [2].

In adhesive wear model [2], the energy required to remove a certain amount of material is compared with the total work done.

The wear efficiency is expressed as a report between the energy absorbed in wear and the total mechanical work done [2]:

$$K = \frac{V H}{\mu F S}$$  \hspace{1cm} (1)

where:

- K is wear efficiency;
- F - friction coefficient / specific energy or wear factor;
V – volume of metal removed from the worn surface [in\(^3\)/ft];
H – Brinnell hardness;
\(\mu\) – coefficient of friction between the wearing surfaces;
S – distance of sliding contact de contact traveled by the rotating tool joint;
\(F_n\) – normal contact forces between the surfaces.
K and H, respectively F values table 2 [2] are given for different casing steel garde

Reputable oil and gas operators have performed experiments and laboratory tests in
order to validate and modify the developed casing wear models to be applicable in
real life and practical results.

### Table 2. Wear properties of casing grades (White and Dawson, 1985) [2]

<table>
<thead>
<tr>
<th>Mud type</th>
<th>Casing grade</th>
<th>Wear efficiency, K</th>
<th>K/H, [in(^3)/lbf]</th>
<th>Hardness, H [psi]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water based</td>
<td>K55</td>
<td>0.0001</td>
<td>3.6(^{-10})</td>
<td>277778</td>
</tr>
<tr>
<td></td>
<td>N80</td>
<td>0.00023</td>
<td>8.1(^{-10})</td>
<td>283951</td>
</tr>
<tr>
<td></td>
<td>P110</td>
<td>0.00063</td>
<td>1.4(^{-10})</td>
<td>450000</td>
</tr>
<tr>
<td>Oil Based</td>
<td>K55</td>
<td>0.0006</td>
<td>2.2(^{-10})</td>
<td>272727</td>
</tr>
<tr>
<td></td>
<td>N80</td>
<td>0.0012</td>
<td>3.9(^{-10})</td>
<td>307692</td>
</tr>
<tr>
<td></td>
<td>P110</td>
<td>0.0017</td>
<td>4.2(^{-10})</td>
<td>404762</td>
</tr>
</tbody>
</table>

### Table 3. Experimentally determined wear factors [3]

<table>
<thead>
<tr>
<th>Drilling fluid</th>
<th>Tool joint</th>
<th>Wear factor (F), [E(^{-10}) psi(^{-1})]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water + bentonite + barite</td>
<td>Smooth</td>
<td>0.5 - 1</td>
</tr>
<tr>
<td>Water + bentonite + lubricant 2%</td>
<td>Smooth</td>
<td>0.5 - 5</td>
</tr>
<tr>
<td>Water + bentonite + drilled solids</td>
<td>Smooth</td>
<td>5 - 10</td>
</tr>
<tr>
<td>Water</td>
<td>Smooth</td>
<td>10 - 30</td>
</tr>
<tr>
<td>Water + bentonite</td>
<td>Neted</td>
<td>10 - 30</td>
</tr>
<tr>
<td>Water + bentonite + barite</td>
<td>Slightly rough</td>
<td>20 - 50</td>
</tr>
<tr>
<td>Water + bentonite + barite</td>
<td>Rough</td>
<td>50 - 150</td>
</tr>
<tr>
<td>Water + bentonite + barite</td>
<td>Very rough</td>
<td>200 - 400</td>
</tr>
</tbody>
</table>

Regardless what is the source of selection for the wear factor, this is measured in
E\(^{-10}\) psi\(^{-1}\) so for example, a wear factor of “8” means 8 E\(^{-10}\) psi\(^{-1}\) which shall be used
effectively in calculations. In the models used to predict the qualitative wear it is
very important to pick up a realistic wear factor F.

The formula (1) should be re-written in a more convenient form for further
calculations, therefore the following abbreviations and considerations shall be used
in such a way that it can be obtained the term V which is the volume of material
removed from the inner face of the subject casing, due of the adhesive wear.

\[ V_z = \frac{K \mu S}{r_{TJ}} \]

\(V_z\) - Rate of penetration [ft/hr];
\(L_h\) – Length of the subsequent borehole to be drilled – usually the length of the
production hole having already set the intermediate casing which is the exercise
subject casing [ft];
\(r_{TJ}\) - Tool joint radius [in];
\(D_{TJ}\) - External diameter of the tool joint [in];
L_{TJ} - Length of the tool joint [ft];
ω - Rotation per minute / rotational speed of the drilling string;
DP_{JL} - Length between two consecutive tool joints (drill pipe body length) [ft];
T - Exposure time [3]:
\[ T = \frac{L_{TJ} \omega}{DP_{JL}} \quad \text{[hrs]} \]  

R - Well curvature radius for each point where the calculations are done in order to determine the axial forces [ft];
S - Sliding distance of the tool joint while rotating / unit of drilled hole [ft];
F_a - Axial force in drilling string in each calculation point (every 100 ft or every 30 m);
F_n - Normal force on tool joint:
\[ F_n = L_{TJ} \frac{F_a}{R} \quad \text{[lbs/ft]} \]  

L = Lateral load on drill pipe:
\[ L = F_n \cdot L_{TJ} \cdot DP_{JL} \quad \text{[lbs/ft]} \]  

As has been mentioned above, the wear factor which controls the wear efficiency, is determined effectively in laboratories for different conditions [2, 3]. The equation (1) can be re-formulated as:
\[ V = \frac{60 \pi F L D_{TJ} \omega L_h}{V_z} \]  

where:
V is the volume of casing wear / unit length [in\(^3\) / ft];
F - wear factor factorul de E\(^{10}\) psi\(^{-1}\);
L - lateral load on drill pipe / unit length [lbs/ft];
D_{TJ} - external diameter of tool joint [in];
L_h - drilled length [ft];
V_z - rate of penetration [ft /hr];
\( \omega \) - rotations per minute.

The length of tool joint and the length of drill pipe tube does not appear in the above equation because they are not affecting under linear model considerations the metal quantity lost by wear.

Equation (5) is applied for the lateral forces are picked up from the diagram of figure 1, respectively from 25 lbs to 3500 lbs (11 daN to 1540 daN), and the drilling parameters as per Section d.

Also, in this paper calculations are done just for the 7 in casing covering 3-unit weights and two type of tool joints. The results are representing the qualitative wear results, and are displayed in table 4. The graphic representation, is reflected in figure 2, including the technological limits for the collapse pressure and the allowable normal forces on tool joint imposed by well design (trajectory shape, subsurface equipment limitations, maximum dog legs, friction factors etc.)
Table 4. Qualitative wear, in %, for a specific casing and tool joint

<table>
<thead>
<tr>
<th>Casing</th>
<th>Tool Joint</th>
<th>L80</th>
<th>Formations</th>
<th>WTAB on 5-1/2&quot; OD28 mm</th>
<th>WTAB on 4 1/2&quot; OD21 mm</th>
</tr>
</thead>
<tbody>
<tr>
<td>35</td>
<td></td>
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<td></td>
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<tr>
<td>30</td>
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</tbody>
</table>

| 425 0.181 | 1550 0.682 | 1000 0.60 | 14 0.14 | 4,267 | 425 0.181 | 1550 0.682 | 1000 0.60 | 14 0.14 | 4,267 |
|--------|------------|---------|-------|-------|--------|------------|---------|-------|-------|--------|
3. Graphic interpretation

- The well designer is imposing a range of normal forces on tool joint deriving from the limits of miscellaneous equipment which shall be operated / installed in the hole while drilling the production hole or while running completion; in this case 350 to 550 daN on tool joint. At this point the Dog Leg Severity, the shape of the well does not matter.
- The well designer is imposing the technological limits for the intermediate casing qualitative wear, as per the Company policies, in this case 4 to 6%.
- From the casing design (biaxial or triaxial) has resulted as acceptable, an intermediate casing of 7 in OD; L80; 51.1 kg/m.
- The drilling contractor will provide a drilling string consisting of drill pipe OD 4 in; G105 with HT40 tool joints, working inside of the intermediate casing.
- The subsequent horizontal section will have 1000 length, and shall be drilled with positive displacement motor having 60 RPM applied from surface top drive system.
- The assumed ROP will be 4.2 m/hr.
- From the imposed lateral forces on tool joint and drilling with the above conditions, the estimate of qualitative wear is going to be 4 to 6% being as per the Company policies. Consequently, the well planner - directional drilling service company can set a well trajectory which may induce as per the torque and drag...
models, lateral forces on tool joint no more than 550 daN, providing there are not other technical limitations. Therefore, this casing is accepted from the qualitative wear standpoint.
- If the well planner, after running torque and drag models related to the trajectories & operations, comes up with lateral forces on tool joint over 550 daN (say 800 daN for example), and he can not optimize the dog leg severities, trajectory shape etc., for realistic technical reasons, then because the qualitative wear will jump to 9%, sure the subject intermediate casing profile should be changed, and also the drilling string/tool joints reconsidered.

4. Conclusions and recommendations

Based on the results and analysis, the following conclusions are extracted:
• Among other factors, casing wear is dependent of the well trajectory path, with emphasis on the Dog Leg Severity values, drilling parameters including the ROP.
• Although this method is referring only to the qualitative aspect of the casing wear, neglecting totally the wear geometry and the depth of the wear groove, still remains a fast tool in order to assess the percentage of the casing wear.
• This method is sensitive with the selection of the wear factor.
• Beside of the percentage of casing wear per unit length, the casing wear is developing under a very specific pattern and geometrical form, and dimensions. This subject is not treated in this paper, but this is another very important matter to be considered.
• The casing wear values and positions, even from qualitative stand point only, is to be carefully considerate in well design – casing design and drilling operations for directional, ERD, horizontal wells, HPHT, critical sour wells with emphasis on well control scenarios, well stimulation scenarios, and all operations which are related with the casing burst and collapse pressures.
• The calculation of lateral forces on tool joints should be included in any scope of work for any well planner-directional drilling service company.
• Using this method, it will keep safe not only the intermediate casing from the qualitative wear stand point, but also the drilling string because using the API RP7G lateral forces on tool joint diagram, will imply in fact rotating these pipes in curved holes having maximum dog leg severity below the values generating high fatigue stress.

In order to reduce the casing wear, oil and gas operators, well designers, field representatives, are encouraged to use some preventive measures as:
- design the well at minimum DLS and take into considerations real DLS 1.75 – 2 times higher than designed;
- reduce RPM at the rotary table / top drive system so use motor performance drilling;
- minimize the exposure time by increasing the ROP;
- employ the drill pipe protectors;
- use tool joint materials to minimize the casing wear;
- use thicker wall casing along such intervals where the casing wear is to occur at high values;
- keep the drilling fluid clean and add lubricant to minimize the casing wear;
- perform time to time casing wear prediction calculations, and if the well is high profile, run specific caliper logging suites to determine the real casing wear and compare against the predicted.

References
[1] *** API RP 7G.