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Casing Wear Prediction in Horizontal Wells

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Abstract

Casing is considered one of the main well barrier elements to keep well integrity. Casing wear reduces the casing thickness and hence reduces the well integrity. Therefore, the aim of this article is to predict the reduction in wall metal quantity of the casing for horizontal wells. The connection between the hydrocarbons well design (well path, dog leg severities, casing design, loads in drilling string) and the casing wear is explained, with the related consequences which are resulting off this undesired phenomenon. Furthermore, the wellbore trajectory is optimized and the dogleg severity is computed in order to determine casing wear. Drillstring loads' distribution are also determined. A sensitivity analysis is implemented in order to show the impact of weight on bit (WOB), drillstring rotation (RPM), rate of penetration (ROP), and wear factor (WF) on casing wear prediction. A horizontal well WP1A is taken and studied to predict the casing wear. The maximum DLS resulted in this well is 12°/30m. The higher the RPM values, the higher WOB, the higher WF, and the lower ROP are; the higher casing wear, the higher reduction of casing thickness and the higher probability to loss well integrity are.

Keywords: *Casing wear prediction; Horizontal wells; Trajectory optimization; Sensitivity analysis; Drag and buckling conditions.*

1. Introduction

Casing wear is an ordinary phenomenon that is taking place and influencing on the inner wall surface of a casing pipe due to the following actions [1-2]:

- Drillstring rotation and the interaction of abrasive materials
- The pressure resulting from the contact between the outer surface of the drillstring/ tool joints and the inner surface of casing string

Based on field experience and offset well design studies, there are direct and indirect factors which generate the casing wear. On one hand, direct factors [1-2,4] are wellbore dogleg severity, casing internal diameter, external diameter of drillstring/ tool joints, the nature of casing and drillstring surfaces, lateral forces on tool joints, time exposure while rotating and penetrating inside casing, and casing wear coefficient. On the other hand, indirect factors [1-2] are annulus dimensions, flow rate, and drilling fluid type, temperature, PH value, sand content and acid content.

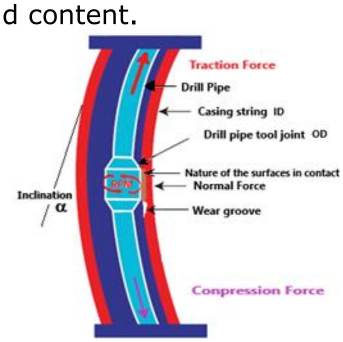

Fig. 1 Factors generating casing wear [1-2]

The casing wear can be quantified by measuring the reduction in wall metal quantity of the casing pipe or by directly localizing in specified points of the casing string. The quantity of the metal lost is representing the reduction of casing thickness after the wear process took place in a certain pipe section. The wall thickness reduction of the casing results in the reduction of the rated burst pressure and the rated collapse pressure for the specific length of the worn casing. Therefore, this will affect all the further/or future operations in the well while performing something related to internal and external pressures [1-2]. Additionally, this will decrease the well integrity in which one of the most important well barriers is going to be weakened.

In spite of casing wear problem, the Industry does not have an exact and typical method for the casing wear evaluation and predictions. However, there are some theoretical prediction models which have been developed and then modified by the oil and gas operators such as Eni based on their options, field conditions and experience and laboratory tests. Moreover, the casing wear has been modeled and analyzed on the petroleum industry through many studies and researches [1-6]. These studies have reached a conclusion that, at 250 psi contact pressure, the wear caused by the interaction between casing inner wall and drillstring outer surface is inducing a qualitative change in which the wear mechanism is transformed from abrasive to adhesive wear. Also, it's known that the adhesive wear is much severe than abrasive wear [1].
According authors experience in drilling field operations and well design, they have been noticed that:

- In vertical wells, the casing wear is relative minor and is located just at a couple of casing joints below of the well head, but this issue is becoming extremely important from the burst pressure stand point for the well control situations. Furthermore, if the subject vertical well is suffered major trajectory corrections having as result high values of the dog leg severity, then the casing wear may occur over these intervals.
- In directional wells regardless the trajectory path, the casing wear intervals will occur between the kick off point and the end of build point. Likewise, the casing wear will be important over the all intervals having high values for dogleg severity.

An accurate prediction of casing wear is crucial to enhance well integrity and the hole life, decrease the over-engineering of casing designs in progressively complex drilling programs, and prevent catastrophic casing failures produced by wear as well. Therefore, from the technical stand point, the question is what might be an acceptable wear of the subject casing and where this wear has appeared along of the casing string. In order to provide an optimum well design in such way to insure the desired well life is non-altered by the casing wall thickness reduction induced by casing wear, the well designer should strongly cooperate with all subsurface team members and the field operations team.

Table 1 Wear properties of casing grades [1]

Mud type	Casing grade	Wear efficiency K	K/H [In^2/lbs]	Hardness H [psi]
Water based	K55	0.0001	3.6-10	277778
	N80	0.00023	8.1-10	283951
	P110	0.00063	1.4-10	450000
Oil based	K55	0.0006	2.2-10	272727
	N80	0.0012	3.9-10	307692
	P110	0.0017	4.2-10	404762

Table 2 Wear factors [2]

Drilling fluid	Tool joint	Wear factor (F) [E^{-10} psi^{-1}]
Water + bentonite + barite	Smooth	0,5 - 1
Water + bentonite + Lubricant 2%	Smooth	0,5 - 5
Water + Bentonite +Drill Solids	Smooth	5 - 10
Water	Smooth	10 - 30
Water + bentonite	Smooth	10 - 30
Water + bentonite + barite	Slightly rough	20 – 50
Water + bentonite + barite	Rough	50 - 150
Water + bentonite + barite	Very rough	200 - 400

The aim of this paper is to determine the connection between the hydrocarbons well design (well path, dogleg severities, casing design, loads in drilling string) and the casing wear prediction, with the related consequences which are resulting off this undesired phenomenon. In order to show this impact of well design on casing wear, there are several items that should be computed before making wear prediction such as casing wear formulas, loads distributions, survey calculation, dogleg formula, and wearing factor selection.

Table 3 Experimentally determined wear factors [4]

Selections		Wear factor E^{-10} psi^{-1}
Mud type	Water or water based, steel tool joint	0.5 to 40
	Oil based mud, steel tool joint	0.3 to 5
Tool joint material	Smooth tungsten carbide	8.5
	Very rough tungsten carbide	1625
	Other proprietary casing friendly hard banding	1 to 6
Rotating drill pipe protectors	Pipe protector started with rusted casing	4.1
	Pipe protector with average casing interior	2.1
	Pipe protector after polishing casing	0.06

2. Casing wear prediction

Based on the energy concept, basics of adhesive casing wear due the action of the drillstring tool joints in the inner wall surface of casing have been developed and modeled [1-4]. The energy concept is based on comparing the energy required to remove a certain amount of metal to the total work done. Reputable oil and gas operators such as Eni 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. In order to compute the metal volume removed from the worn surface of casing worn away by rotating the tool joints, the following derived equations are provided and utilized [1-4].

$$V=\frac{Energy\ absorbed\ in\ wear}{Total\ mechanical\ work\ done}=\frac{\text{Energy input per Foot}}{\text{Specific Energy}}=\frac{V\ H}{\mu Fn\ S} \quad (1)$$

$$F=\frac{Friction\ Factor}{Specific\ Energy} \quad (2)$$

$$Input\frac{Energy}{ft}=Friction\frac{Force}{ft}\ x\ S \quad (3)$$

$$Friction\frac{Force}{ft}=f_f\ .Tool\ Joint\frac{Load}{ft} \quad (4)$$

$$S=n\ .D\ .N\ (RPM).T \quad (5)$$

$$T=\frac{S\ L_{TJ}}{P_R\ L_{DPJ}} \quad (6)$$

$$S=\frac{60\ \pi\ D\ N\ S\ L_{TJ}}{P_R\ L_{DPJ}} \quad (7)$$

$$Input\frac{Energy}{ft}=f_f\ .TJ_{LLPF}\left[\frac{60\ \pi\ D\ N\ S\ L_{TJ}}{P_R\ L_{DPJ}}\right] \quad (8)$$

$$V=\frac{60\ \pi\ D\ F\ L\ N\ S}{P_R} \quad (9)$$

where

$$L=\frac{TJ_{LLPF}\ L_{TJ}}{L_{DPJ}} \quad (10)$$

$$TJ_{LLPF}=\frac{F_a\ L_{TJ}}{R} \quad (11)$$

D= Tool Joint Diameter [in]; F = Wear factor [in^2/lbs] or [psi^{-1}]; Fa= Axial force in drilling string at each point of calculation [lbs] f_f= Friction Factor; L= Lateral Load on drill pipe per foot [lbs/ft]; L_{DPJ} =Drill Pipe Joint Length [ft]; L_{TJ}= Tool Joint Length [in]; P_R=Penetration Rate [ft/hr]; R= Curvature radius of the hole at each point of calculating axial forces; S=Drilling distance [ft]; T= Time exposure of tool joint; TJ_{LLPF}= Tool joint lateral load pound per foot = Normal force on Tool Joint; N=Rotary speed of the drilling string [RPM]; V= Wear volume per foot [in^3/ft].

It's essential to note that the tool Joint and drill pipe lengths do not appear in Eq. 9 because they do not influence the amount casing wear in the linear model [2]. Additionally, the Wear Factor, F, is controlling in fact the wear efficiency and it is estimated by laboratory experiments in various conditions [1-2]. A paramount in casing wear prediction is the accuracy of the Wear Factor F. Sources are generally provided by the Oil in Gas Operators studies, determinations and experiments or Industry Reports as the Table 4 [2]. Regardless the source for selecting the Wear Factor, it's measuring unit is E-10 psi-1 so for example a Wear Factor of "8'' means 8 E-10 psi-1 for calculations. The K and H values (Table 3) are given for different casing steel grade in the presence of water and oil based mud [1], or in Table 4 as per ENI Casing Design Manual [2].

3. Drillstring loads' distribution

In order to predict the casing wear; the loads distribution of drillstring and its parameters while drilling and rotations, and well trajectory parameters should be determined. The drag equations 12 through 13 for linear and curved holes and the buckling conditions as defined by the equations 14 through 18 are presented and explained [3-6].

$$\sum_{i=2}^{n} F_i = \sum_{i=2}^{n} F_{i-1} + \sum_{i=2}^{n} [\beta w \Delta L \, cos\alpha]_i \pm \sum_{i=2}^{n} [\beta w \Delta L sin\alpha \;\; \mu \;\; sin\Psi]_i \;\gg\; linear \tag{12}$$

$$\sum_{i=2}^{n} F_i = \sum_{i=2}^{n} F_{i-1} + \sum_{i=2}^{n} \left[F_{i-1} \;\left(e^{+(-)\mu_i \theta_i} - 1 \right) \sin \Psi_i \right] + \sum_{i=2}^{n} [\beta w \Delta L sin\alpha \;\; \mu \;\; sin\Psi]_i + \sum_{i=2}^{n} \{\beta_i \, w_i \, \Delta L_i \, [\frac{sin\alpha_i - sin\alpha_{i-1}}{\alpha_i \; - \; \alpha_{i-1}}]\} \quad \gg \; inclined \tag{13}$$

$$F_{cr} = 2 \left(\frac{E \, I \;\, \beta \, W}{r} \right)^{1/2} \tag{14}$$

$$F_{cr} = 2 \left(\; E \; I \;\;\beta \; W \, \sin \frac{\alpha}{r} \right)^{1/2} \qquad \gg inclined \; hole \tag{15}$$

$$F_{cr} = 2.55 \; (E \; I \;\; [\beta \; W]^2)^{1/3} \qquad \gg vertical \; hole \tag{16}$$

$$F_{EI} = (2 \; [2]^{1/2} - 1) \;\;\; F_{cr} \qquad \gg inclined \; and \; horizontal \; hole \; sections \tag{17}$$

$$F_{EI} = 2.18 \;\; F_{cr} \tag{18}$$

where:

F_{cr} = Critical force at sinusoidal buckling [N]; F_{EI} = Critical force at helical buckling [N]; W = Unit weight of the tubulars [N/m]; β = Buoyancy coefficient of the tubulars; α =Borehole inclination angle at the measuring point [rad]; E = Elasticity modulus [N/m^2]; I = Inertial momentum of the tubular material section [m^4]; r = Tool Joint radius [m].

In case of the higher the axial load in compression than the critical loads (Eq. 14), the tubulars will enter in sinusoidal buckling and the critical loads equation will become equations 15 through 16 for curved and vertical holes respectively. For a vertical borehole, the tubular material will buckle fast due of friction forces effect in hole as appeared in preceded equations [3-6]. The sinusoidal buckling effect deduced from the friction forces is somehow typical and acceptable in the drillstring. When the compression loads is overcoming the subsequent critical forces, a new pattern in buckling is to happen. This is helical buckling, which is generally developing in horizontal and inclined wellbore sections. In vertical wellbore sections, the helical buckling is confirmed to be 2.2 times more than the sinusoidal buckling as has been established in previous studies [3-6]. Inserting the well parameters, drilling string and BHA parameters, drilling parameters as weight on bit, rotations / minute and rate of penetration, and taking into consideration the sign as "+" is for pulling out the drilling string and "_" is for running in drilling sliding and reaming, the loads of the drilling string (buckling regime) and the normal force on the tool joint, in such a way that using the previous equations can therefore be estimated. Hence, the percent of casing wear per meter can also be determined.

4. Horizontal wellbore trajectory

Trajectory optimization and computations of a borehole are considered a key factor in casing wear prediction. Mathematical calculations of hole trajectory have been presented and provided for vertical, inclined and horizontal wells [7-9]. However, solving the kick off point (KOP) problem, selecting the mud density, and the most common surveying method (Minimum Curvature Method, MCM) are here presented. More details have already been discussed and provided. In order to determine KOP, the mathematical equations 19 through 23 for calculating KOP in the combination trajectory horizontal well plan are simultaneously solved by programming. The other problems appeared during planning a horizontal turn and vertical turn in the horizontal section of the planned wellbore have been solved and presented [7-9]. Moreover, mud weights for horizontal wellbore are selected based on equation 24. The MCM equations for well trajectory planning and directional survey evaluation are also shown as follows

$$Inclined\ TVD = R_1 sin\varphi_1 + T\cos\varphi_1 + R_2(sin\varphi_3 - sin\varphi_1) \quad (19)$$

$$Inclined\ DEP = R_1(1 - cos\varphi_1) + T\sin\varphi_1 + R_2(cos\varphi_1 - cos\varphi_3) \quad (20)$$

$$Inclined\ MD = R_1\,\varphi_1 + T + R_2\varphi_2 \quad (21)$$

$$Departure\ of\ the\ REACH = REACH\ x\ sin\varphi_3 \quad (22)$$

$$Change\ in\ TVD\ of\ the\ REACH = REACH\ x\ cos\varphi_3 \quad (23)$$

$$MW_{horizontal} = MW_{vertical} + (OBW - LOT)\frac{1-cos2\varphi}{1.6} \quad (24)$$

$$F = \frac{\Delta MD}{\beta}\tan\frac{\beta}{2} \quad (25)$$

$$\Delta X = (sin\varphi_1 cos\vartheta_1 + sin\varphi_2 cos\vartheta_2)RF \quad (26)$$

$$\Delta Y = (sin\varphi_1 sin\vartheta_1 + sin\varphi_2 sin\vartheta_2)RF \quad (27)$$

$$\Delta Z = (cos\varphi_1 + cos\varphi_2)RF \quad (28)$$

$$DLS = \frac{100}{\Delta MD}[\Delta\varphi^2 + (\Delta\vartheta\ \Delta\varphi)^2]^{1/2} \quad (29)$$

where:
RF= Ratio Factor; DLS= Dog-leg severity, deg./100 ft; β= Dog-leg angle, deg; φ=inclination angle; deg. ϑ=Azimuth angle, deg.; MW= Mud weight, ppg; OBW = Overburden weight (Overburden stress), ppg; LOT= Leak off test value, ppg.

5. Casing wear prediction flow diagram

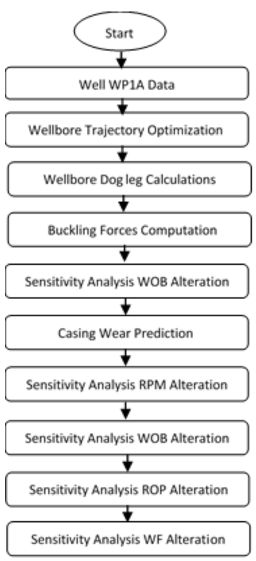

Fig. 2 Casing wear procedures

Fig. 2 shows a flow diagram of the casing wear prediction procedures. The procedures of casing wear are required to determine the wellbore trajectory, the dogleg severity, drag forces, and buckling conditions in order to determine the percentage of wall thickness worned from the casing.

Table 4. Main Data Well WP1A

MD [m]		5460
TVD [m]		2872.3
KOP [m]		2670
Last casing P110	OD [inch]	7
@ 3060/2899 m MD/TVD	ID [inch]	6.125
	q [lbs/ft]	29
Drilling diameter [inch]		6.125
Drilling fluid density [ppg]		9.6

Table 5. Tubulars and drilling string parameters Well WP1A

Parameter	OD [inch]	ID [inch]	M/Up Tq. [lbs ft]	w Corrected [lbs/ft]	Tension [lbs]
PDM	4.75	1.75	23 602	40.3	45 000
NMDC	4.75	1.5	23 602	54.3	49 4000
MWD/LWD	4.75	2.25	23 602	46.7	60 700
PF1 S135 New	4	3.24		17.87	261 000
TJ HT40	5.25	2.56	39 872		
HWDP Premium	4	2.5625		30.9	407 000

Parameter	OD [inch]	ID [inch]	M/Up Tq. [lbs ft]	w Corrected [lbs/ft]	Tension [lbs]
TJ T 40	5.25	2.56	39 872		
PF2 S135 new	4	3.24		17.87	586 000
TJ HT40	5.25	2.56	39 872		

6. Well WP1A case study

In order to make visible the influence of hole dogleg severity and the drilling parameters as the weight on bit, rate of penetration (ROP) and rotations (RPM) of the drilling string over the casing wear values, a horizontal well WP1A has been considered and studied. Well design and simulation data are:

- Wear Factor F=5.6 E^{-10} psi^{-1} **(**Clear Drilling fluid for the pay zone water, bentonite +lubricant 2**%). (Subject to a sensitivity study).**
- Tool Joint Type HT 40 Length = 0.6 m (1.96 ft) Steel smooth AISI 4145.
- OD Tool Joint 5,125” (130.1 mm).
- Intermediate Casing OD 177,8 mm (7”) P110 x 42,3 Kg/m (31,6 lbs/ft); shoe set at 3060 m (10099 ft) MD
- Horizontal section (production to be drilled) length= 2400 m (7895 ft)
- Rate of Penetration while drilling in Reservoir ROP = 6m/hr. (19.7 ft/hr.) **(Subject to a sensitivity study).**
- RPM RT/TDS RPM=60 to 100 **(subject to a sensitivity study)**
- Weight on Bit WOB=5000 daN (11240 lbs) to 10000 daN (22480 lbs) **(subject to a sensitivity study).**
- Lateral / horizontal production section Drilling Diameter 155.7 mm (6,125”).
- Mud density: 1.2 SG (9.96 ppg.).
    - BHA and drilling string as per the **Table 5.**

7. Results and discussion

WP1A well is a horizontal well with measured depth MD = 5460 m, true vertical depth TVD = 2872.3 m and the selected KOP= 2670 m based literature basics and past field experience. In order to predict the casing wear in well WP1A, directional and horizontal parameters should firstly be determined. The trajectory respective vertical projection, horizontal projection and DLS variation is shown in the Figs. 3 through 5. The maximum DLS resulted in this well is 12^{o}/30m.

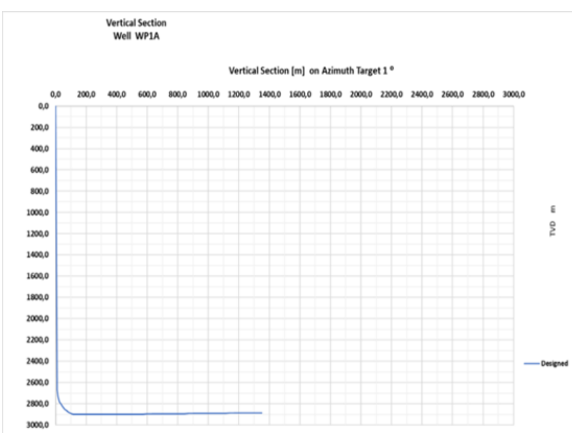

Fig. 3. Vertical projection of well WP1A

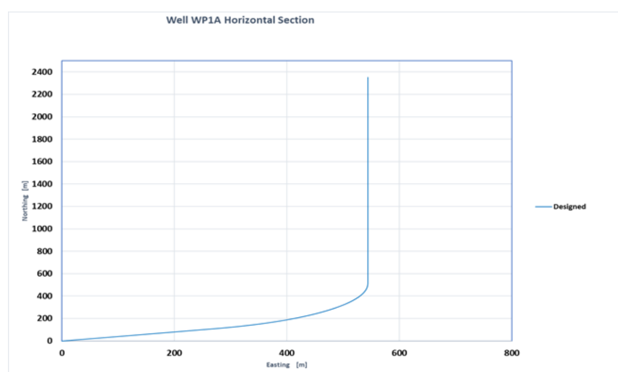

Fig. 4. Horizontal projection of well WP1A

Using well WP1A data, trajectory parameters, the drilling string parameters, drag equations 12 through 13, and the buckling conditions as defined by the equations14 through 18; the loads distribution in drilling string while drilling with rotations are determined at WOB=5000 lbs, ROP= 6 m/hr. and RPM = 60. Buckling conditions (axial forces) are appeared in Figs. 6

and 7. Moreover, the conditions of buckling show that, under normal accepted drilling parameters, the buckling status of the drillstring is well below of the critical sinusoidal buckling values. If the WOB increases to 15000 daN for unforeseen reasons, then the drillstring will buckle slightly over the sinusoidal and helical buckling (2600 m MD & Figs. 6&7) with consequences over the casing wear.

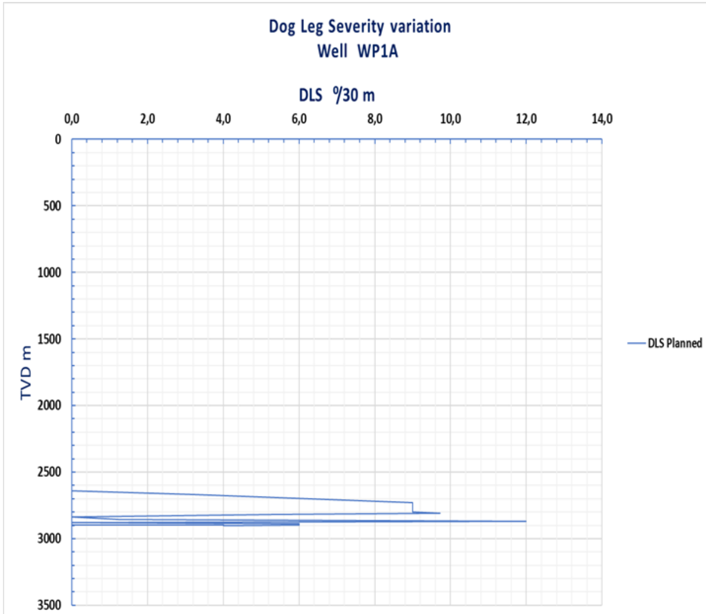

Fig.5. DLS variation of well WP1A

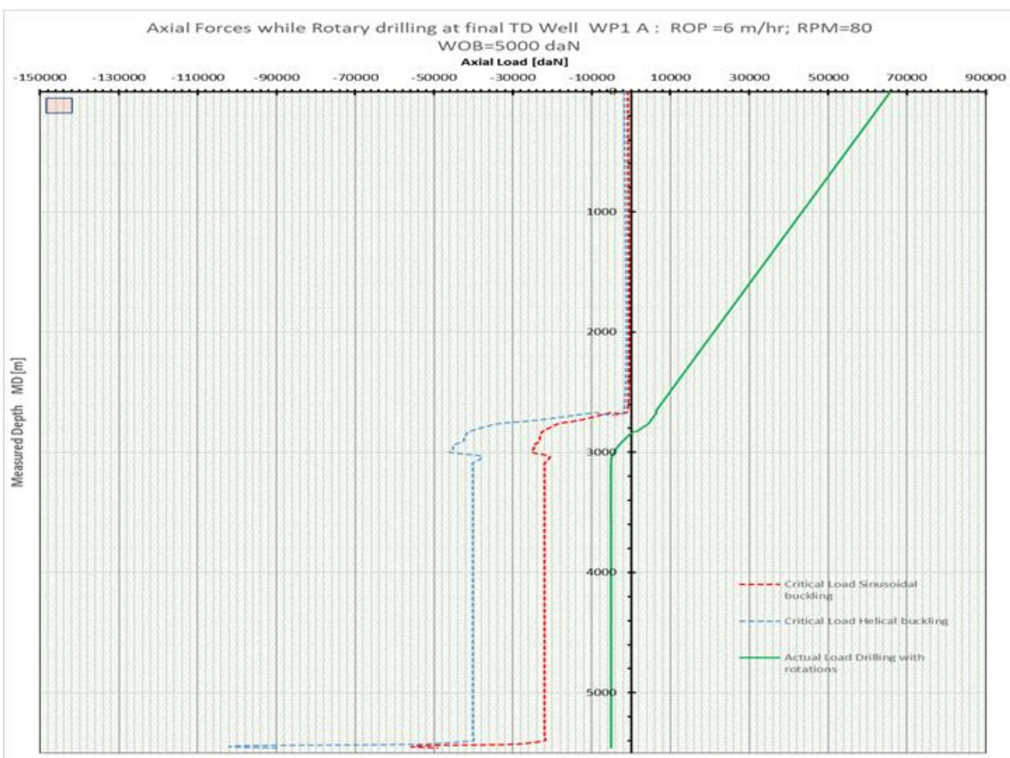

Fig.6. Buckling status in drilling string Well WP1A at WOB 5000 daN

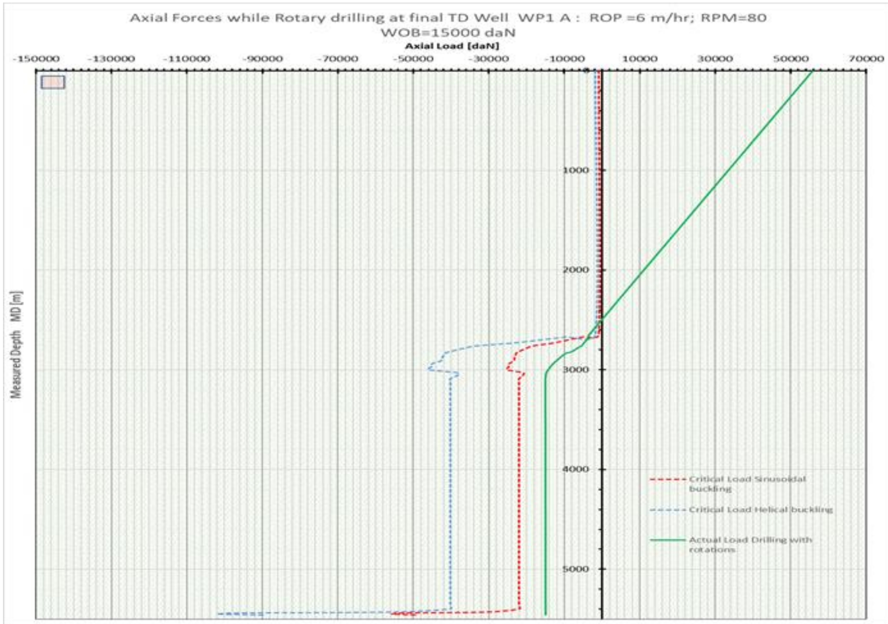

Fig.7. Buckling status in drilling string well WP1A at WOB 15000 daN

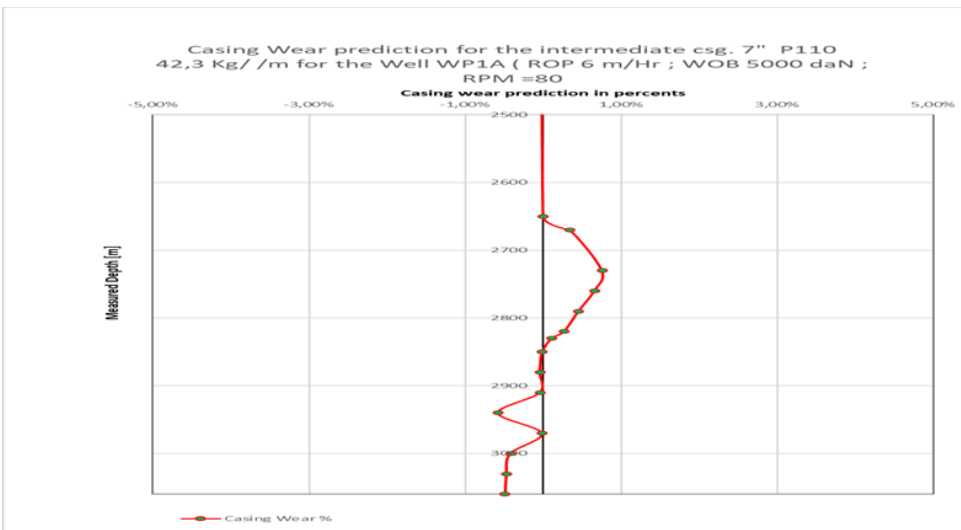

Fig.8. 7” WP1A well casing wear prediction

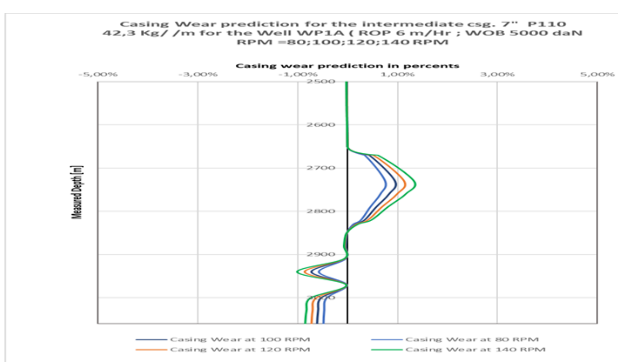

Fig.9. Casing wear trend as RPM is increasing

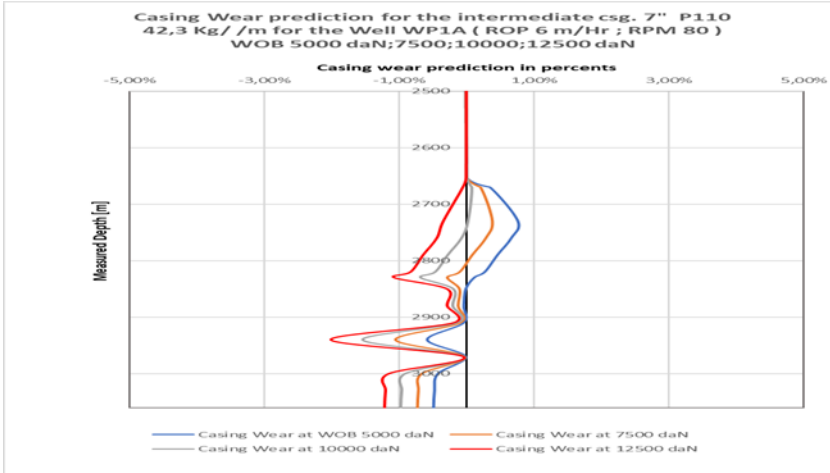

Fig.10. Casing wear trend as WOB is increasing

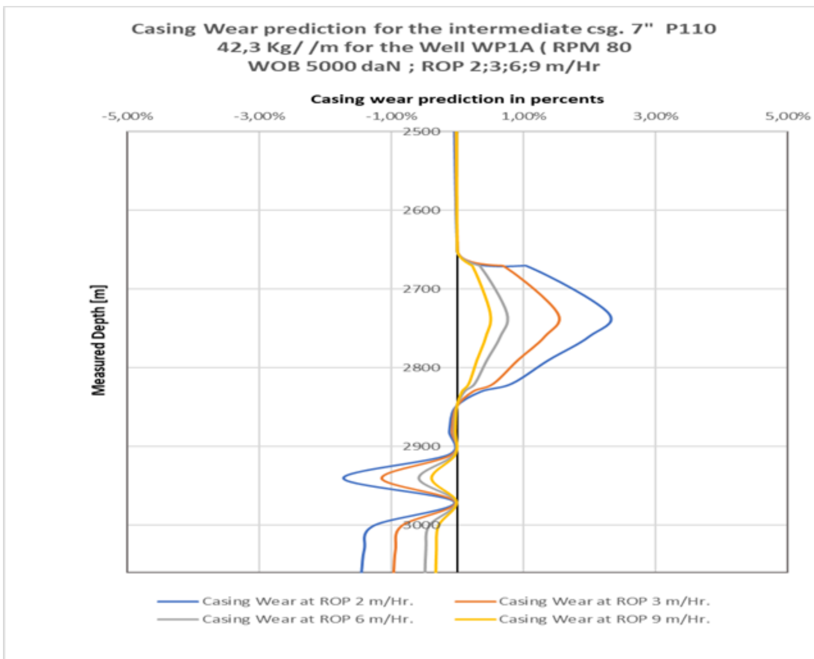

Fig.11. Casing wear trend as ROP changes

After that, casing wear can be predicted taking into consideration that the zero normal forces in the vertical interval of the well, and the non-zero forces in the horizontal and deviated sections. There is no any casing set in horizontal section, therefore the prediction will be done just for the 7" casing P110 42,3 Kg/m with emphasis on the buildup interval which is from the KOP (2670 m MD) to the casing shoe (3060 m MD). According to convention, the calculated drag forces acting will be positive while pulling up the drilling string and negative while slacking off the drilling string (drilling, reaming, and sliding). Having the normal forces, drag forces, wellbore trajectory, and dogleg severity calculated, the casing wear percentage can be calculated and predicted for 80 RPM, 5000 daN WOB and 6 m/hr. ROP as shown in Fig.8. A sensitivity analysis of casing wear is done due to RPM, WOB, ROP, and wear factor alterations as shown in Figs. 8 through 12. By convention sign, "negative wear" means that the low side of casing will be worn and "positive wear means that the high side of the inner surface casing will be worn.

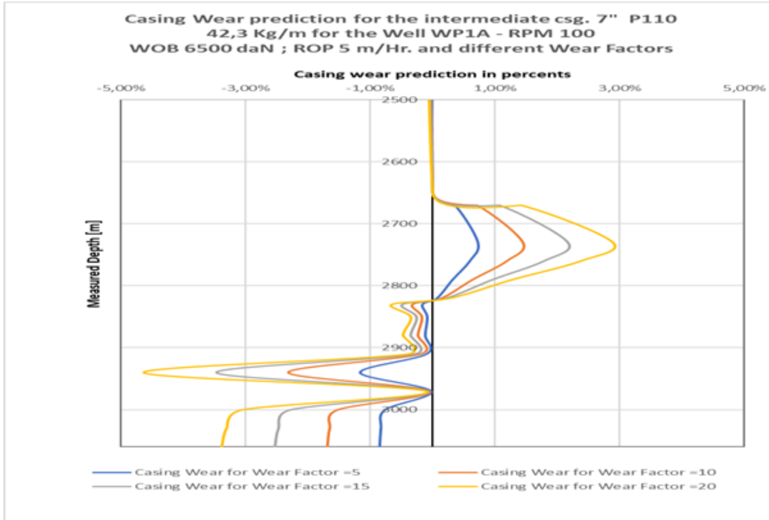

Fig.12. Casing wear trend as wear factor is increasing

After that, casing wear can be predicted taking into consideration that the zero normal forces in the vertical interval of the well, and the non-zero forces in the horizontal and deviated sections. There is no any casing set in horizontal section, therefore the prediction will be done just for the 7" casing P110 42,3 Kg/m with emphasis on the buildup interval which is from the KOP (2670 m MD) to the casing shoe (3060 m MD). According to convention, the calculated drag forces acting will be positive while pulling up the drilling string and negative while slacking off the drilling string (drilling, reaming, and sliding). Having the normal forces, drag forces, wellbore trajectory, and dogleg severity calculated, the casing wear percentage can be calculated and predicted for 80 RPM, 5000 daN WOB and 6 m/hr. ROP as shown in Fig.8. A sensitivity analysis of casing wear is done due to RPM, WOB, ROP, and wear factor alterations as shown in Figs. 8 through 12. By convention sign, "negative wear" means that the low side of casing will be worn and "positive wear means that the high side of the inner surface casing will be worn.

In order to show the effect of RPM on the casing wear, all parameters are kept constant (WOB, ROP and Wear Factor F) and the RPM will be modified from 80 to 100, 120, and 140 rotations per minute. It can be seen that the casing wear is increasing as the RPM values are increasing (Fig.9). If the WOB; RPM and Wear Factor are constant, but the ROP is decreasing, then the casing wear is increasing. However, if the ROP, RPM and Wear Factor are kept constant and WOB is increasing, then the casing wear is increasing (Fig.10). As the WOB is increasing, the casing wear zone is shifting towards the low side of the inner surface casing due of the buckling in the drilling string. The casing wear can reach high values, so is not advisable to drill with the drilling string buckled at high values. For ROP changes, the higher ROP, the lower the casing wear percentage (Fig.11). This means that increasing the ROP reduces the exposure time of casing and hence reduces the casing wear. Another key point for the casing wear is the quality of the drilling fluid and its solid contents. In the preceded calculations, the Wear Factor was taken 5.6 x E^{-10} $psi^{-1.}$ Because the drilling fluid is Water + bentonite + Lubricant 2% and tool joints are smooth. If the same drilling fluid has a higher solids content, the wear factor should then be considered for instance 8.25 x E^{-10} psi^{-1}. The higher the wear factor, the higher the casing wear percentage (Fig.12). The quality of the drilling mud including the solids content and barite content is a very sensitive subject because it can drive the wear factor at very high values on the daily basis in field operations.

8. Conclusions and recommendations

Based on the results and analysis, the following conclusions are extracted:

- Casing wear is dependent of the well trajectory path with emphasis on the dogleg severity values, and drilling parameters including the ROP.

- Casing wear is influenced by the type and the quality of the drilling fluid
- The prediction of the casing wear is very sensitive with the selection for 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 is to be carefully considered in well 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.

In order to reduce the casing wear, oil and gas operators, well designers, field representatives, and article results 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.

Conversion factors

Ft x 0,3048 = m	*psi/ft x 22,62 = kPa/m*
Ft x 12 = in	*pf/gal x 0,1198 = kgf/l*
Bbl x 0,15894 = m^3	*Nm x 0,102 = kgf m*
Atm msl x 14,691 = psi	*Bar x 14,503 = psi*
Kgf/l x 62,4278 = lbs/ft3	*Kgf x 2,20462 = lbf*
In^3*/ft x 53,7633 =* cm^3*/m*	*Lbf x 0,4448 = daN*
Lbf/ft x 1,4881594 = Kg_f*/m*	*Psi x 0,0689475 = bar*

Lx61.025844=in^3

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