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Computerized Kill Sheet for Most Drilling Operations

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ABSTRACT

This paper addresses a portion of what is actually needed for deep water operations involving well control procedures for directional and horizontal drilling.

Drillpipe pressure schedules were investigated together with the analysis of surface pressure gauge limit to avoid further gas influx and predict the onset of casing shoe fracture.

Examples are run mainly using directional and horizontal well data illustrating the procedure and operation.

INTRODUCTION

Standard kill sheets are limited in their use to vertical wells, and pressure drop calculations are simplified mainly to facilitate filling out the forms. A computer kill sheet by Leitão et. alli.[1] was developed to handle common well control drilling problems from land to deep waters with and without deviation control. The method made use of more accurate pressure drop calculations using the drilling fluid rheological data throughout a wide span of shear rates (basically the 6 FANN35 readings). Several kill muds could be used throughout the control sequence and a computer program was written to handle the calculations on a personal computer with interactive graphic capabilities to provide the user with an operational procedure update after every actual operation.

As a continuation to what has already been developed, the theory in this paper will address a practical problem that is normally shown on the conventional kill sheets through one or at most two numbers - the maximum casing pressure (or kill line pressure for offshore floating vessels) at which the casing shoe fracture or casing burst will occur Fig 1.

References and figures at end of paper.

WELL CONTROL PROCEDURE

The basic task in well control is to circulate out the kick maintaining the bottom hole pressure constant and sightly higher than the pore pressures within the exposed formation. Several methods have been developed for such purposes [2] including one rigorous one [1].

This paper also deals with a second constraint, the casing shoe pressure, at which formation fracture will occur (an example of these pressure values is given in the Appendix). Once the fracture is initiated, the circulation losses could lower the bottom hole pressure and therefore promote further formation fluid influx that could quickly lead to an underground blowout. It is important to quickly recognize when this situation has occurred.

Casing wear can sometimes require an unexpected reduction in the maximum allowable casing pressure. The procedure in a critical well control situation, where casing rupture pressure is being approached, is to operate the choke such that the casing shoe pressure remains sightly below the fracture pressure until these pressures drop as the gas phase (or intrusion fluid phase) passes by that point. Of course this procedure will incur in an additional influx of fluids from the higher pressure formation since bottom hole pressure was necessarily lowered during this operation. Fortunately the computer program can handle all these situations since this problem is an accounting one to keep track of the fluid boundaries (interfaces) and therefore can calculate the new drillpipe schedule to be followed, assuming that the new gas or fluid influx was smaller than the first one, otherwise there is no solution to the problem and the ability to safely shut-in the well will be lost.

Assuming an offshore situation with the wellhead placed at the mudline, the measurement of the shoe pressure is done by reading the surface kill line gauge pressure corrected by the fluid densities within the kill line and casing.

The kill line fluid density is assumed here to be known and constant. Unfortunately such an assumption isn't appropriate for the casing annular space since there will be several different fluids and fluid mixtures throughout the circulation process starting with the original drilling fluid while taking the kick, followed by a gas cut mud (for a gas kick), gas, and one or more kill drilling fluids and this will certainly alter the hydrostatic difference between the well head and the casing shoe.

The single phase fluid calculations are well known and straight forward for both drilling fluid and gas. The problem arises for multiphase flow in straight and specially deviated portions. In theory if an accurate prediction is possible the calculation for the surface pressure gauge reading would follow what is show in Fig. 2. The pressure distribution would be calculated in the annular space and the difference between the well head pressures and shoe pressures could be obtained through subtraction. The graph shows that only while multiphase region does not enter the casing annulus the pressure difference is constant. The graph also shows that another constraint is the wellhead or casing pressure upper limit (P_{ww}) that shouldn't be exceeded.

The calculations described to this point have made use of the knowledge of the pressure distribution within the annular space and therefore a model for such predictions is necessary. The accuracy of such a model is important if the onset of formation fracture is to be predicted with a high degree of confidence.

MATHEMATICAL MODEL AND COMPUTER PROGRAM FOR THE WELLBORE CHOKE-LINE PRESSURES

The theory and the computer program selected have been described in detail by Otto Santos [3].

MATHEMATICAL MODEL AND COMPUTER PROGRAM FOR THE DRILLPIPE PRESSURE SCHEDULES

The theory and the computer program have been described in detail by Leitão et. alli. [1].

FIELD SIMULATED EXAMPLES

The three examples that will be presented were designed to demonstrate the impact of the water depth, maintaining all other parameters constant (casing shoe pressure resistance will also change), on the kill line pressure safety region which limits shoe fracture pressures and additional kicks from formation fluids.

The basic well characteristics during the drilling stage of these examples are shown in Fig. 4. Notice that we are considering an offshore situation with a floating vessel, and a wellhead placed on the mud line. The water depth scenarios to be studied are shown in Fig. 5.

As all pertinent data is given to calculate the drillpipe pressure schedule using the rigorous method the computer program given in Ref. 1 (complete listing of the program is provided in that paper) is run and the output is show in Fig. 5.

During the first few minutes the drillpipe pressure rapidly increases as the pump is ramped up to its normal operating speed. Only during the pump start up the surface casing pressure is controlled through the use of the choke, to follow the pressure schedules shown in Fig. 6 for well #1. This allows for a constant bottom hole pressure during the starting up, at this stage of the well control process (around 1 to 3 minutes).

After the pump reaches it steady state condition the drillpipe schedule should be followed and will indicate a drop in pressure due to the higher mud weight of the killing fluid, and will decline in a linear fashion in the straight part of the well. As soon as the buildup portion is reached, the pressure schedule becomes non-linear reaching a minimum at the point at which the hydrostatic pressure gradient equals the changes in the pressure losses due to hydrodynamic friction after which this last effect predominates up to the horizontal section. In the horizontal section a linear pressure schedule is shown as only changes in hydrodynamic friction are taking place. As soon as the new mud strikes the bit there is a sharp pressure change due to the difference in pressure losses of both drilling fluids through the bit after which the pressure should stabilize if constant bottom hole pressure is to be maintained.

To make the drillpipe pressure schedule for the rigorous method of any practical meaning several viewing functions were incorporated into the program such as:

1. A scroll table at the upper right hand corner that allows for a digital readout as precise graphic values would be hard to obtain;
2. Zoom capabilities to easily blowup any part of the graph;
3. A printscreen function to obtain hard copies quickly;
4. As many kill drilling fluids can be used in sequence and a function key was included to keep track of the last killing mud used;
5. A main menu can be selected to update information or data.

Due the computing flexibility built-in to the program (written in Turbo C), there is no constraint in adapting it immediately to any automated well control procedure.

A little more on Fig. 5. As the true vertical depth of all three wells are the same and there is no change in them but the sea water depth, this figure pertains to all three cases. Fig. 6 is exclusive to well #1 since it depends on the water depth.

Up to this point we have discussed and presented the rigorous method, that assures constant bottom hole pressure throughout the well control operation and has been adequately implemented on a computer allowing for the use of several different killing drilling fluids, even sea water if necessary.

The next step consists in assuring that during the well control operation that the maximum allowable casing pressure is not reached. In addition we would like to be able to quickly detect when formation fracture has occurred.

As shown in the Appendix, the best way to assure this is to monitor the kill line and not the choke line pressure gauge, cheking to see if the upper safety limit is not exceeded. This upper limit is a function of the drilling fluid flow rate, its rheology and the annular and choke line geometries and spatial configurations.

Using the theory initially explained the kill gauge pressure safe working region is shown in Fig. 7 for well #1. Again we emphasize that the upper limit depends upon the quality of the pressure predictions within the two phase flow region (gas and mud) within the annular space and the kill line. Otto's [Ref. 2] model was used here.

Above the upper limit, the fracture will occur and below the lower limit a new kick will take place. If these two lines ever meet, formation fracture is predicted. This graph is what we suggested be used at rig site or while planning and/or designing the well. Only the upper limit is actually monitored since the lower limit should be taken care of through the correct use of the drillpipe pressure schedule.

Another practice such as the one shown in Fig. 8 is not recommended. This practice suggests using the shoe pressure corrected by a hydrostatic column of fluid to the kill line gauge up to the moment the gas top reaches the shoe (using the gas slug displacement model). After this the upper limit is considered to be the BOP or casing resistance (whichever is lowest) at the mud line corrected by the hydrostatic fluid of liquid in the kill line. For this particular example it is easily seen that this procedure can lead to errors above 4,000 psi. The same is true for wells #2 and #3 shown in Fig. 11 and 14 respectively.

Another practice is to select the smallest pressure value among the BOP, Casing and casing shoe (corrected to the kill line surface gauge pressure) and assume this as the upper limit. For shallow waters (900 ft or less) shown in Fig. 8 the error could be as large as 270 psi meaning that the operator could induce a kick unnecessary since he could allow a pressure increase at this value. As water depths increase Figs. 11 and 14 this error decreases 170 psi for well #2 (water depth of 2,100 ft) and 100 psi for well #3 (water depth of 3,000 ft). This means that the error on the upper limit is more pronounced for shallow waters.

To shown the water depth influence in the annular region pressures similar graphs as those discussed up to now were plotted and are shown in Figs. 9, 10, 12 and 13. All previous discussion applies to these graphs too.

CONCLUSIONS

The rigorous method allow for a precise drillpipe pressure schedule to maintain the bottom hole pressure constant. This lower limit should not be violated unless a higher priority constraint is to be exceed such as the maximum allowable pressure without casing burst.

The analysis of the pressure behavior in the annular region lead to a kill line surface pressure limit that should not be exceeded at any time since casing fracture jeopardizes the entire well control operation and could lead to a disastrous situation.

Through the use the computer procedure suggested complex calculations can be easily handled by the well control operator including several killing muds since all accounting is taken care of.

Erros in assuming the kill line gauge pressure upper limit based on the smallest pressure values of the wellhead, the BOP and the casing resistance are more critical for shallow water depth wells.

NOMENCLATURE

A	= Area, in^2
D	= Depth, ft
G	= Pit Gain, bbl
m	= Mole Mass
M	= Molecular Weight
n	= Total Moles
P	= Pressure, psi
R	= Universal Gas Constant, $10.732 \frac{(psi)(ft^3)}{(lbmole)(R)}$
S	= Pump Speed, $Strokes$
T	= Temperature, F
V	= Volume, bbl
Z	= Gas Deviation Factor
ρ	= Specific Mass, lb/ft^3

Subscripts

A	= Point on Fig. 15
B	= Point on Fig. 15
cr	= Casing Shoe Resistance
cs	= Casing Shoe
csg	= Casing
g	= Gas
h	= Kill Line Hydrostatic
ku	= Kill Gauge Upper Limit
m	= Minimum
wh	= Wellhead
ww	= Wellhead Weak Spot
e	=Equivalent
BHP	=Bottom Hole Pressure

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References

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2. Bourgoyne Jr., Adams T.; Chenevert, Martin E.; Millhein, Keith K.; Young Jr, F. S., "Applied Drilling Engineering", SPE Textbook Series, Vol 2, 1986.

3. Santos, Otto A., "Important Aspects of Well Control for Horizontal Drilling Including Deepwater Situations", IADC/SPE 21993, 1991 IADC/SPE Drilling Conference, Amsterdam, March 1991.

Appendix

STUDY OF KILL GAUGE PRESSURE UPPER LIMIT FOR A GAS SLUG MODEL.

This example is based on the configuration shown in Fig. 15. This appendix is intended to draw the following conclusions:

i) The kill line pressure gauge should be used to control the annular pressure upper limit to predict formation fracture or wellhead breakdown. To demonstrate this Part 4 illustrates the error that occurs using the choke line pressure gauge against the kill line one.

ii) Two phase flow models could reduce the error in the kill line gauge pressure limit depending on how accurate they can predict the annular pressures. This is shown in Part 5.

NOTE:
The gas single slug model was used in this appendix example (in the main text and the programs, a two phase flow model was used). Parts 1 and 2 illustrate the annular pressure changes using the slug model.

1) Equation for a static column of gas:

$$PV = nR(T+460)Z \ 144 \tag{1}$$

$$n = \frac{m}{M} \tag{2}$$

$$\rho = \frac{PM}{ZR(T+460) \ 144} \tag{3}$$

$$dP = \rho dx \tag{4}$$

where x → vertical depth.

$$dP = \frac{PM}{144ZR(T+460)}dx \tag{5}$$

$$\int_{P_1}^{P_2} \frac{dP}{P} = \int_{D_1}^{D_2} \frac{M}{144ZR(T+460)}dx \tag{6}$$

$$\ln\frac{P_1}{P_2} = \frac{M(D_2-D_1)}{144 \times 1 \times 10.73 \times (460+T)} \tag{7}$$

$$P_2 = P_1 e^{\left(\frac{M(D_2-D_1)}{1,545(460+T)}\right)} \tag{8}$$

$$P_2 - P_1 = \Delta P \tag{9}$$

$$\alpha = \left(\frac{M(D_2-D_1)}{1,545(460+T)}\right) \tag{10}$$

$$\Delta P = (P_1 e^{\alpha} - P_1) \tag{11}$$

$$\Delta P = P_1(e^{\alpha} - 1) \tag{12}$$

2) Calculation example:

$$D_2 - D_1 = 4,400 \tag{13}$$

$$M = 16(methane) \tag{14}$$

$$T = 200 \tag{15}$$

$$\alpha = 0.06904 \tag{16}$$

$$e^{\alpha} - 1 = 0.0715 \tag{17}$$

$$\Delta P = 14.7 \times 0.071 \tag{18}$$

$$\Delta P = 1.05 \tag{19}$$

for:

$$P_1 = (3,000 + 14.7) \tag{20}$$

$$\Delta P = 214 \tag{21}$$

3) Additional data for Fig. 15:

$$G = 30 \tag{22}$$

$$P_{BHP} = 5,821 \tag{23}$$

4) Maximum casing pressure at A.

a) considering a static column of liquid in the choke line.

$$(P_A)_{max} = 3,090 \times 0.7 + .052 \times 8.5 \times 4,342 \tag{24}$$

$$(P_A)_{max} = 4,082 \tag{25}$$

$$(P_{csg})_{max} = 4,082 - .052 \times 9.2 \times 4,390 \tag{26}$$

$$(P_{csg})_{max} = 1,982 \tag{27}$$

$$(P_{csg})_{max} = P_{ku} \tag{28}$$

b) circulating.

$$(P_f)_{chokeline} = 280 \tag{29}$$

$$(P_{csg})_{max} = 1,982 - 280 \quad (30)$$

$$(P_{csg})_{max} = 1,702 \quad (31)$$

$$P_{ku} = 1,982 \quad (32)$$

$$\Delta P_{ku} = 0 \quad (33)$$

$$(\Delta P_{csg})_{max} = 280 \quad (34)$$

This means that using the casing pressure gauge, the error could be as much as 280 psi while the kill line pressure gauge doen't induce such an error.

c) static column of gas.

$$(P_{csg})_{max} = 4,082 - \left[(4,082 + 14.7)\left(e^{\left(\frac{16 \times 4,390}{1,545 \times (460+200)}\right)} - 1\right) - 14.7\right] \quad (35)$$

$$(P_{csg})_{max} = 4,082 - [(4,096.7) \times (0.0713) - (14.7)] \quad (36)$$

$$(P_{csg})_{max} = [4,082 - 277] \quad (37)$$

$$(P_{csg})_{max} = 3,805 \quad (38)$$

$$P_{ku} = 1,982 \quad (39)$$

$$\Delta P_{ku} = 0 \quad (40)$$

$$(\Delta P_{csg})_{max} = 1,823 \quad (41)$$

Notice the large error in using the casing pressure gauge. → kill line gauge should be used.

5) Maximun kill gauge pressure at B

a) Static column of liquid above the casing shoe.

$$(P_{ku})_{max} = 4,084 - 0.052 \times 9.2.(7,410 - 4,390) - 0.052 \times 9.0 \times 4,390 \quad (42)$$

$$(P_{ku})_{max} = [4,084 - 1,443 - 2,053] \quad (43)$$

$$(P_{ku})_{max} = 588 \quad (44)$$

b) Worst case for pressure diference at kill line surface gauge: top of the gas buble at A. Note: solution through trial and error or by root seeking methods such as Newton-Raphson.

$$P_{cr} = .052 \times 7,410 \times 10.6 \quad (45)$$

$$P_{cr} = 4,084 \quad (46)$$

Considering :

$$D_g = 700 \quad (47)$$

$$P_A = 4,084 - .052 \times 9.2 \times (7,410 - 4,390 - 700) \quad (48)$$

$$P_A = 2,974 \quad (49)$$

$$\frac{P_1 V_1}{T_1} = \frac{P_2 V_2}{T_2} \quad (50)$$

$$P_A V_A = P_{BHP} G \quad (51)$$

$$V_A = \frac{(5,821 + 14.7) \times 30}{2,974 + 14.7} = 58.6 \quad (52)$$

$$V_A = 58.6[bbl] \times 5.615 \frac{[ft^3]}{[bbl]} \times 144 \frac{in^2}{[ft^2]} \quad (53)$$

$$V_A = 47,364[in^2 ft] \quad (54)$$

$$A_A = \frac{\pi}{4}(12.515^2 - 5^2) \quad (55)$$

$$A_A = 103.38 in^2 \quad (56)$$

$$D_g = \frac{V_A}{A_A} \quad (57)$$

$$D_g = \frac{47,364}{103.38} = 458.2 \quad (58)$$

Considering :

$$D_g = 458 \quad (59)$$

$$P_A = 4,084 - 0.052 \times 9.2 \times (7,410 - 4,390 - 458) \quad (60)$$

$$P_A = 2,858 \quad (61)$$

$$D_g = \frac{(5,821 + 14.7) \times 30}{(2,858 + 14.7)} \times \frac{(5.615 \times 144)}{103.38} \quad (62)$$

$$D_g = 477 \quad (63)$$

$$P_{kill} = 4,084 - 0.052 \times 9.2 \times (7,410 - 4,390 - 477) - 0.052 \times 9.0 \times 4,390 - \left[(2,858 + 14.7)\left(e^{\left(\frac{16 \times 477}{1,545 \times (460+200)}\right)} - 1\right) - 14.7\right] \quad (64)$$

$$P_{kill} = [4,084 - 1,215 - 2,053 - 7] \qquad (65)$$

$$(P_{ku})_{max} = 809 \qquad (66)$$

$$\Delta P_{ku} = 221 \qquad (67)$$

This means that if the two phase flow region isn't considered in the kill line gauge pressure upper limit, the error in the predictions could be as much as 221psi.

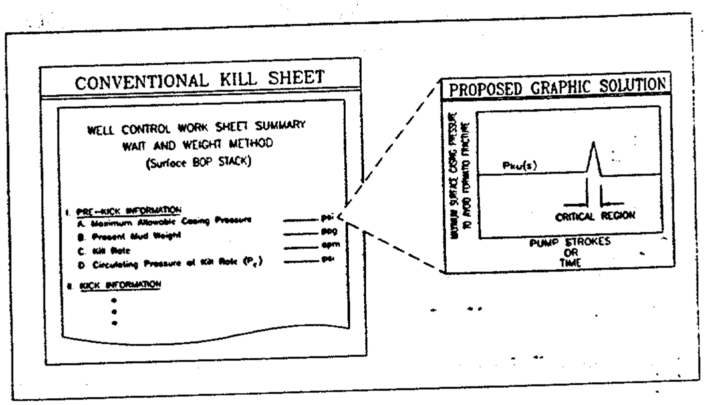

Fig 1. Proposed graphical solution to the casing surface pressure gauge limit to avoid shoe breakdown

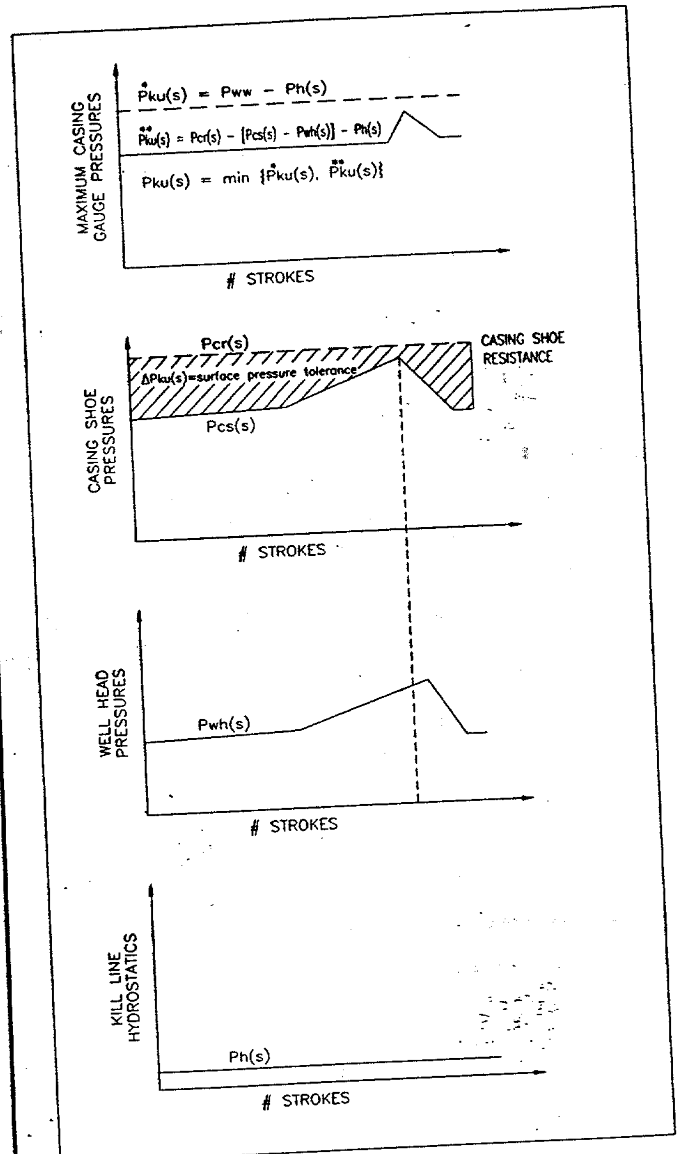

Fig 2. Procedure to calculate the maximum kill line surface pressure gauge readings to avoid casing shoe or well head breakdown

TRUE VERTICAL DEPTH	5646 FT.
TOTAL MEASURED DEPTH	7800 FT.
CASING SHOE DEPTH	4500 FT.
HORIZONTAL SECTION LENGTH	1500 FT.
BUILDUP RATE	5 DEG./100 FT.
WELLBORE DIAMETER	8.5 IN.
DRILL STRING	5 x 3.826 IN.
MUD DENSITY	9 LB/GAL
FLOW BEHAVIOR INDEX	0.9
CONSISTENCY INDEX	0.0003
PLASTIC VISCOSITY	15 CP.
SURFACE TENSION	70 DYNE/CM.
GAS DENSITY	0.7
MUD FLOW RATE (FOR KICK DISP.)	150 GPM
SIDPP	200 PSI
SICP	200 PSI
PIT GAIN	15.5 BBL
INITIAL GAS FRACTION (IN THE FIRST 3 CELLS)	75 %
CELL LENGTH	150 FT.
CHOKE LINE DIAMETER	3 IN.
BOTTOMHOLE TEMPERATURE	140 F.
SEABED TEMPERATURE	40 F.
BIT JET AREA	0.2784 SQ.IN.

CONSISTENCY INDEX IN LBF .SEC^n / SQ.FT.

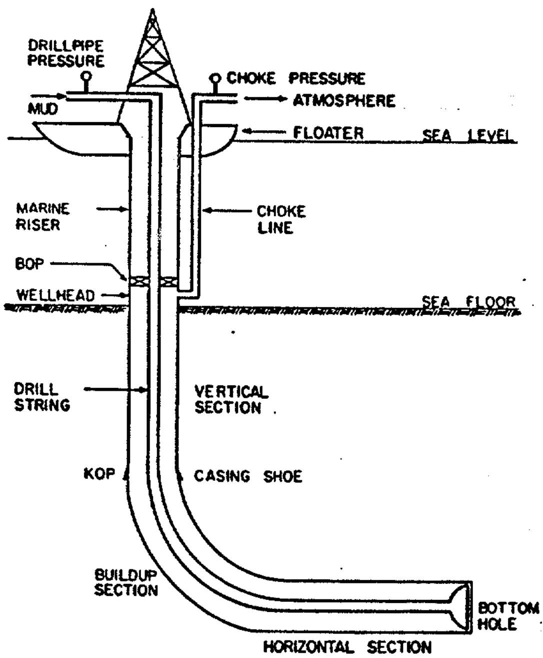

Fig. 3 - Deepwater horizontal well (Ref.3)

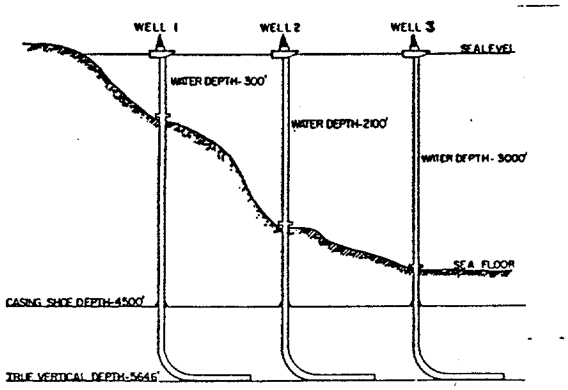

Fig. 4 - Drilling scenarios for the computer simulations (Ref.3)

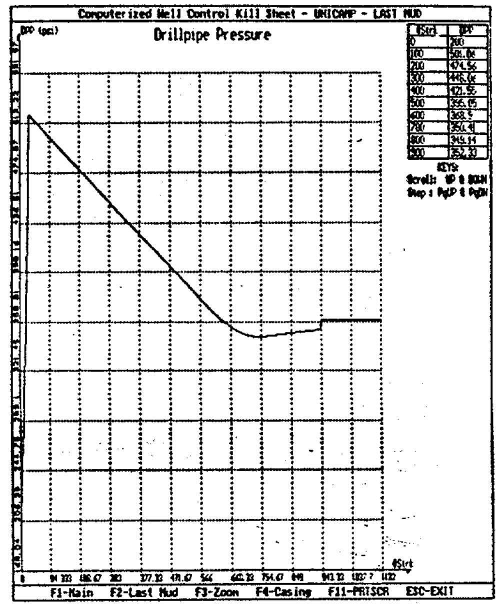

Fig. 5 - Drillpipe pressure schedule for well #1 using the rigorous method.

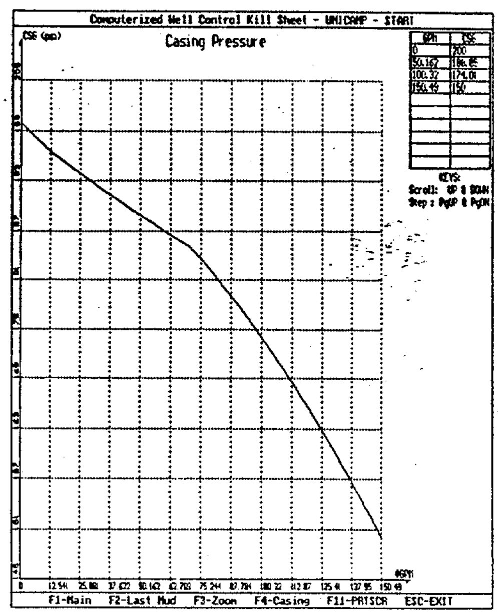

Fig. 6 - Pump startup casing pressure schedule for well #1 using the rigorous method.

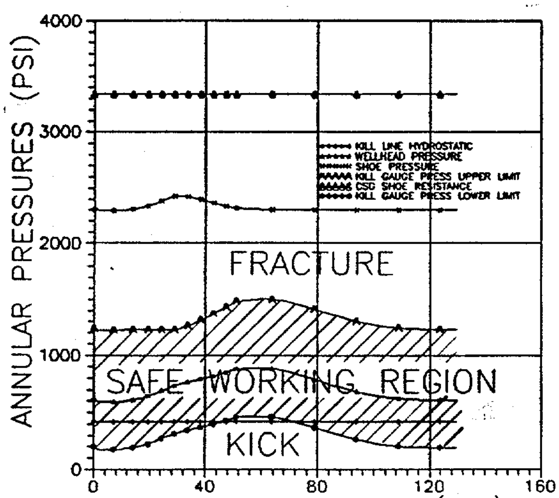

Fig. 7 – Kill gauge pressure safe working region for well #1

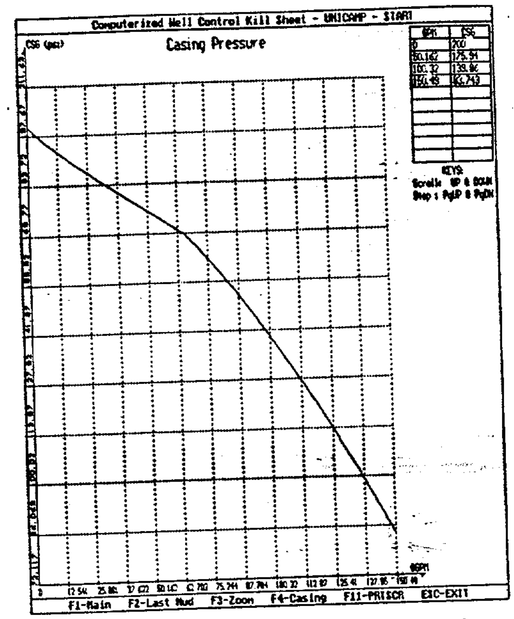

Fig. 9 - Pump startup casing pressure schedule for well #2 using the rigorous method.

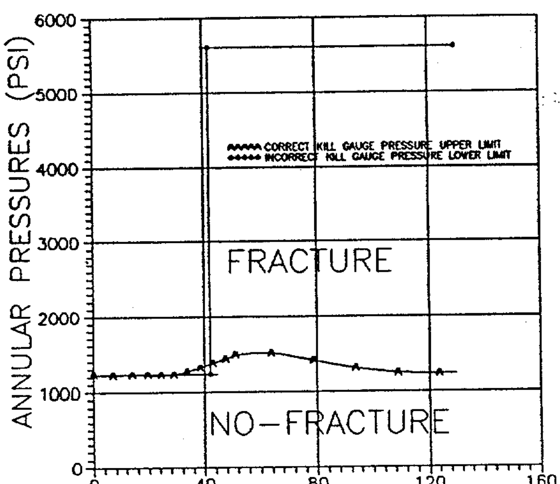

Fig. 8 – Incorrect safe working limit for well #1

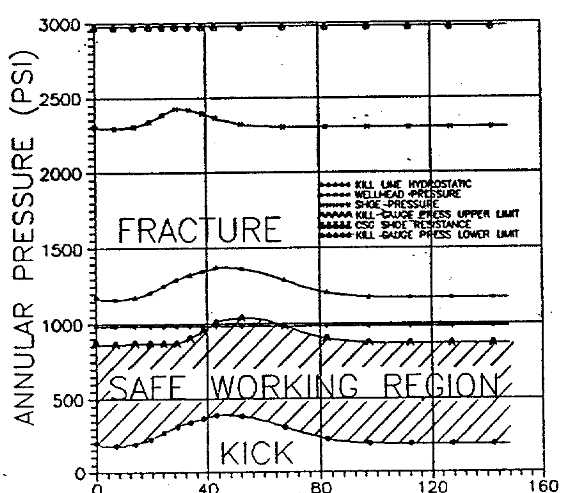

Fig. 10 – Kill gauge pressure safe working region for well #2

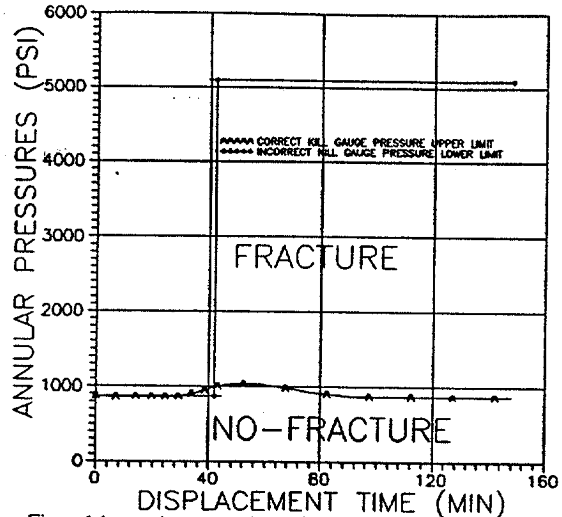

Fig. 11 – Incorrect safe working limit for well #2

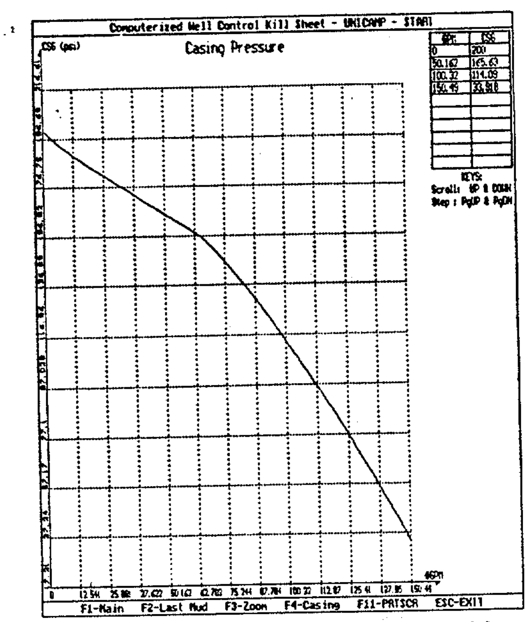

Fig. 12 - Pump startup casing pressure schedule for well #3 using the rigorous method.

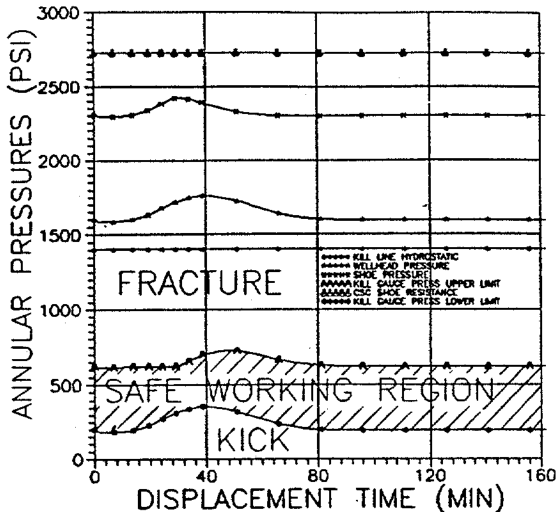

Fig. 13 – Kill gauge pressure safe working region for well #3

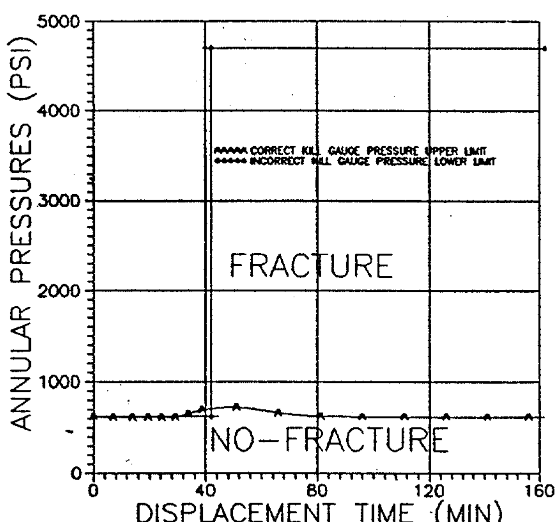

Fig. 14 – Incorrect safe working limit for well #3

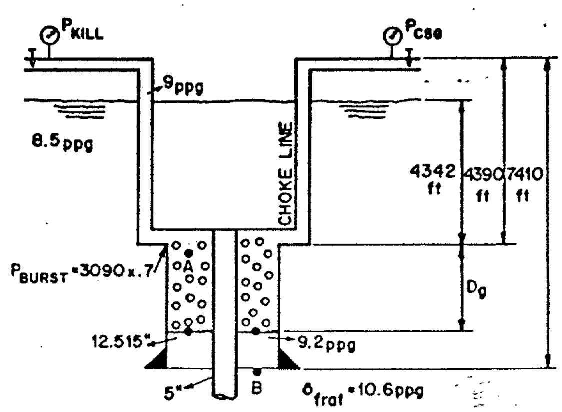

Fig. 15 - Study of kill gauge pressure limits.