

Andrew K. Wojtanowicz*, Koray Kinik*

ENVIRONMENTAL RISK OF SUSTAINED CASING PRESSURE

1. INTRODUCTION

In many parts of the world operators perform casing pressure management programs to monitor and remediate problematic wells having sustained casing pressure at least one of their annuluses. Sustained casing pressure test is performed for each annulus having pressure by bleeding of through ½ inch needle valve and closing the annulus to allow the pressure to build up for 24 hours. The type of fluids recovered and pressure records are reported to regulatory agencies. If the pressure does not build up prior to bleed off, it may be thermally induced or operator induced casing pressures, and typically are not subject to sustained casing pressure regulatory mechanism. Example build-up and bleed-down pressure responses are shown in Figure 1.

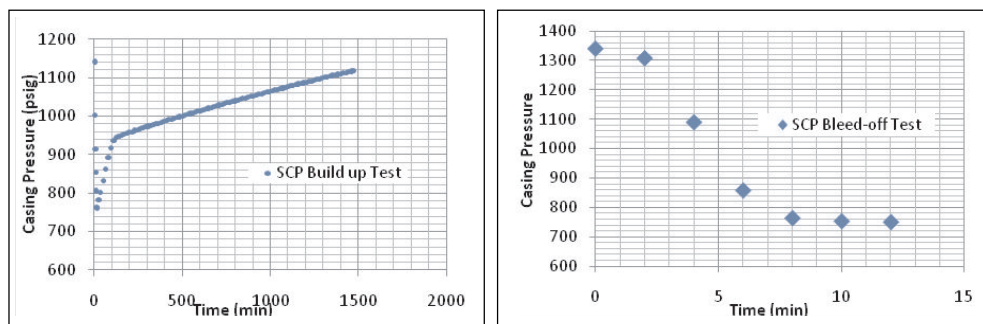


Fig. 1. Example annulus bleed down – build up pressure records

Quantitative risk of SCP can be categorized based on three possible outcomes of the SCP test. Firstly, if the pressure bleeds to zero psig with no buildup, pressure containment

* Louisiana State University

barriers are adequate, thus the annulus in question does not have SCP. Secondly, if the pressure bleeds to zero psig with buildup to the same or lower pressure during test period, the annulus is considered to have an *acceptable* leak rate and barriers for pressure containment are *adequate*. Thirdly, if the pressure does not bleed to zero psig, pressure containment barriers may have partially failed and leak rate may be unacceptable; but still not quantified.

SCP is not a static problem, it may escalate over time as a result of factors such as: increasing micro annuli at the cement-casing or cement-formation contact, damage to primary cement caused by mechanical shock impacts during tripping, thermal cracking caused by different expansion properties of cement and casings, dissolution of cement in acidic formation brine, and condensation of hydro carbons in the micro fractures. Many case studies have reported that initially problem-free wells would develop sustained casing pressure over time [3].

Sustained casing pressure is typically regulated based on wellhead failure scenario. The line that separates monitoring and calling for remediation is set on comparison of critical pressures which the well head can safely handle and the output of the SCP test. Maximum available wellhead operating pressure (MAWOP) is presently used to diagnose the SCP risk and required remediation in both the API and MMS management programs [1, 2]. However, the value of MAWOP is set arbitrarily, and its comparison with the casing pressure does not account for uncertainties. Moreover, the analysis is not only qualitative but also ignores the rate of emission from the wells with sustained casing pressure in case of their external integrity failure.

2. MATHEMATICAL MODEL OF SCP [6]

The model simulates the bleed off and build up pressure in a well with known well configuration, average annular permeability, top fluid level (gas chamber volume) and depth and pressure of the source. It considers linear flow of the gas in cement, which relates the flow rate and pressure at the cement top to the annular permeability, gas source formation pressure and time. Gas migration in the mud column above the cement top is modeled as dispersed two-phase flow. The model assumes constant formation pressure, negligible gas density in the cement column, constant gas deviation factor, compressible mud column, steady-state gas flow at each time step of the iterative computation.

As shown in Figure 2, at each time step gas flow rate, q_c and pressure at the cement/mud interface, P_c , are computed iteratively by numerical solutions in the liquid column with analytical solutions in the cement.

Several parameters can be determined by separately analyzing individual stages of the test. Initial casing pressure is known at the beginning of the test, and the pressure bleed down and the flow rates are recorded during the bleed off test. Those parameters are used to calculate the approximate depth and pressure of the source and the gas chamber volume based on known casing configuration and known depth of top of cement (Fig. 3) [5].

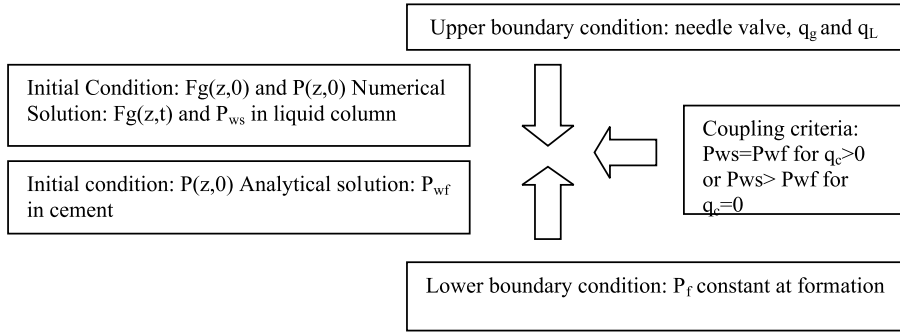


Fig. 2. Coupling Procedure for Mathematical SCP Model

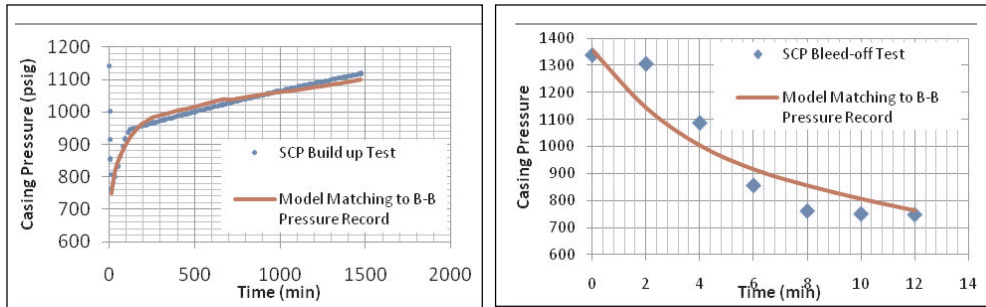


Fig. 3. Matching the data from pressure bleed off and build up with SCP model

3. MAXIMUM EMISSION RATE

In order the hydrocarbons in the reservoir to flow into the atmosphere; the source pressure must overcome the frictional pressure losses through the cement plug and the mud column above it. Thus the pressure balance must be solved for maximum rate that would be emitted to the atmosphere.

$$P_{atm} = P_{source} - \Delta P_c(q_{sc}) - \Delta P_f(q_{sc}) \quad (1)$$

The calculation of maximum rate assumes steady-state flow of gas through the annulus and accounts for depth-dependent compressibility of the mud column resulting from gas-cutting and the effect of geothermal gradient on the mud density. Frictional pressure losses of slipping gas bubbles are neglected. Resultantly, the flow of gas is controlled by the pressure at the top of cement caused by hydrostatic pressure of the gas-cut mud column having compressibility that depends on the gas flow rate. Hence, an iterative procedure is needed to find the rate. The gas flow rate is:

$$q_{sc} = \frac{0.111924Ak(P_R^2 - P_{TOC}^2)}{(T + 520)Lz\mu_g} \quad (2)$$

Here, z and μ_g are strong functions of pressure and temperature calculated at the average temperature of the cement column, and the average pressure.

As the gas-cut mud compressibility varies with depth, pressure at the top of cement is calculated by numerical summation of a discrete column of finite cells. The procedure iterates over different values of gas flow rate until the pressures at TOC computed top-down and bottom-up converge, giving the actual value of the maximum gas emission rate.

4. RISK OF CASING SHOE FAILURE

During the 24 hour SCP test, it is common that the casing pressure does not stabilize within 24 hours test time. In that case, the pressure may build to a pressure such that the bottom-hole pressure at the casing shoe will exceed formation breakdown pressure and start and underground blowout which is not recognizable at the surface [20]. MAWOP provides a safety margin for failure scenario of collapsing of the inner tubular and bursting the outer tubular. MAWOP is 50% of MIYP of the pipe body for the casing being evaluated, 80% of MIYP of the pipe body of the next outer casing or 75% of Minimum Collapse of the inner tubular pipe body, which is the lesser. For the outermost casing, MAWOP is the lesser of 30% of MIYP of the pipe body for the casing or production riser being evaluated or 75% of inner tubular pipe body collapse [2]. For the case study well, MAWOP and casing pressures that will create hydrostatic pressure at the casing shoe have been calculated from the well data and fracture gradients from the leak off tests (LOT), assuming no communication between the annuli.

As shown in Table 1, for annuli C and D, the wellhead failure criterion is more restrictive than the shoe failure criterion. However, for the annulus B, the casing shoe failure criterion appears more restrictive than the wellhead failure. In this annulus, sustained pressure build up at the wellhead would cause failure of the shoe before the MAWOP is reached, resulting in transferring flow of reservoir fluids into the C annulus.

Table 1
Comparison of critical condition for casing shoe breaching with MAWOP for case study well

		MIYP	Collapse	%50 MIYP	%30 MIYP	%75 Collapse	80% MIYP	MAWOP (MMS criteria)	Critical SCP
		psig	psig	psig	psig	psig	psig	psig	psig
Prod. Csg.	9 5/8", 53.5#, Q-125	12390	8440	NA	NA	6330	NA	NA	NA
"B" Annulus	13 5/8", 88.2#, Q-125	10030	4800	5015	NA	3600	8024	4168	1489
"C" Annulus	18 5/8", 136#, N-80	5210	2480	2605	NA	1860	4168	1276	1424
"D" Annulus	24", 256#, Gr.B	1595	742	798	479	557	1276	478	558

For the parameters of the case study well, the regulations would require remedial action if the casing pressure exceeds the MAWOP of 4168 psig. However, the action is needed if SCP rises above 1489 psig.

In addition to comparing deterministic pressure values, a probabilistic approach is used to calculate the effect of SCP on the annular pressure at the casing shoe and the pressure at which the shoe actually fails [4]. The process of a casing shoe failure scenario requires comparison of the annular pressure created by the SCP and annular hydrostatic, and, leak off pressure at the shoe – both being probabilistic quantities. The two pressure values; LOT and maximum SCP; however, are uncertain thus must be described probabilistic distributions, as shown in Figure 4.

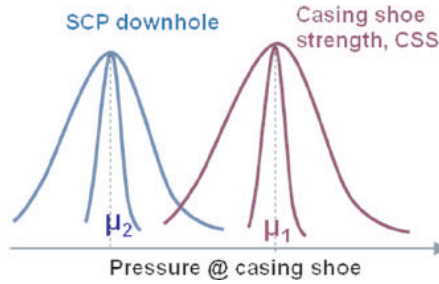


Fig. 4. Probabilistic determination of risk of subsurface well integrity failure

Uncertainty of downhole pressure due to sustained casing pressure at the well head is generated by two components. First, for the pressure build up's that do not stabilize in 24 hours constitute an uncertain SCP_{max} , second, heterogeneous and unknown annular fluid density generates uncertainty in transmission of the SCP_{max} to the bottomhole.

Pressure balance can be expressed in terms of expected values as:

$$E[SCP_d] = E[SCP_{max}] + 0.052 \cdot D \cdot E[\rho_{mud}] \quad (3)$$

Based on the drilling reports, a margin for the density of mud in the annulus is set between 9.5 and 17 ppg for the calculation of hydrostatic pressure and an asymptotic function is derived to define the pressure build up pattern and calculate a most likely value for SCP_{max} .

$$P(t) = a + \frac{b}{(t - t_0)^c} \text{ for } t = t_0 \text{ to } t_\infty$$

$$\lim_{t \rightarrow \infty} P(t) = a \approx SCP_{max}$$

where initial pressure P_o at t_o is:

$$P_o = a + \frac{b}{t_o^c} \text{ and } t_o = \left(\frac{b}{P_o - a} \right)^{1/c}$$

Derived function is a non linear function; therefore it must be linearized for linear regression model to be applied. The function can be moved to a linear domain by a suitable transformation of the model formulation. Thus,

$$\ln(P(t) - a) = \ln(b) - c \cdot \ln(t) \quad (4)$$

Uncertainty of casing shoe strength, which is the second piece of the subsurface well integrity failure mechanism, is generated based on two components. First, determination of surface leak off pressure in a leak off pressure test; second, transmission of that pressure to the bottom-hole are subject to several uncertainties. For example, the surface leak off test pressure (P_{LOT}) analysis is shown in Figure 5.

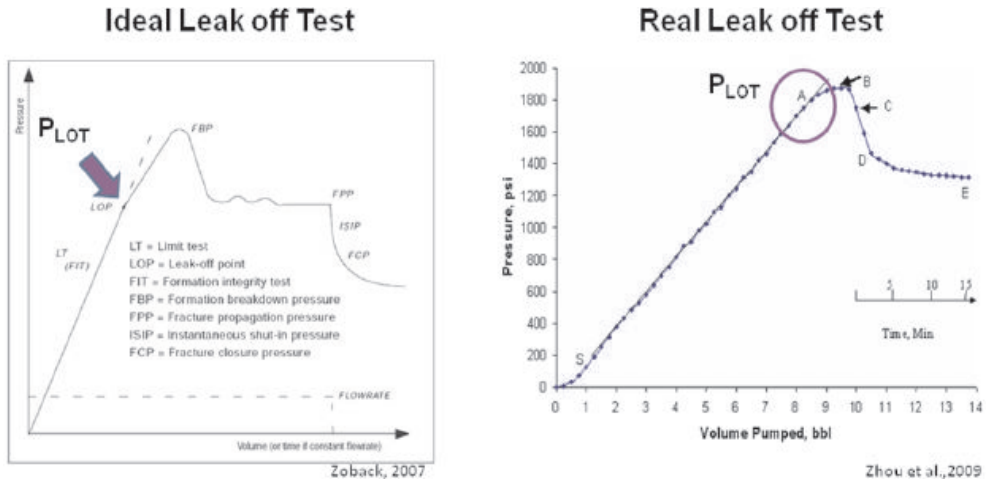


Fig. 5. Leak off testing pressure response charts [7, 8]

Interpretation of P_{LOT} respond charts have been computerized to detect the point that the pressure relationship deviates from linearity, rather than visual interpretation of hand recorded data. Several case studies illustrated discrepancy between calculated and MWD tool measured pressures with field examples [9]. Complications such as the effect of thixotropic mud properties on transmission of surface pressure to the casing shoe [10], mud density variations due to gas dissolution and compressibility of mud [11], effect of mud invasion properties [12], temperature difference between mud and formation [13] cause discrepancy in formation fracture pressure determination. Using the procedure, an expected value of down-hole pressure generated during the leak off test (P_{LOP}) is determined as:

$$E(P_{LOP}) = E(P_{LOT}) + 0.052 \cdot D \cdot E(\rho_{mud}) - \frac{D \cdot \tau_{gel}[E(T)]}{300(d_o - d_i)} + \frac{? \alpha}{1 - v} E(\Delta T) \quad (5)$$

and, Peters made experimental study on mud density variations in high temperature high pressure wells [14]:

$$E(\rho_{mud}) = \frac{\rho_{mud\ surface}}{(1 - f_o c_o [E(T)] - f_w c_w [E(T)]) \cdot P_i} \tag{6}$$

In the above equations (5) and (6), $\Delta\sigma_{thermal}$ is the thermal stresses due to mud-formation temperature difference in psig, E is the Young’s modulus of elasticity and v is the poisson’s ratio. Note that oil compressibility [18] and water compressibility [19] terms in the formula are strong functions of down-hole mud temperature. A certain distribution of possible down-hole temperatures, however, can be estimated since the minimum temperature cannot be lesser than circulating temperature [15, 16] and maximum temperature cannot be greater than the geothermal gradient as shown in Figure 6.

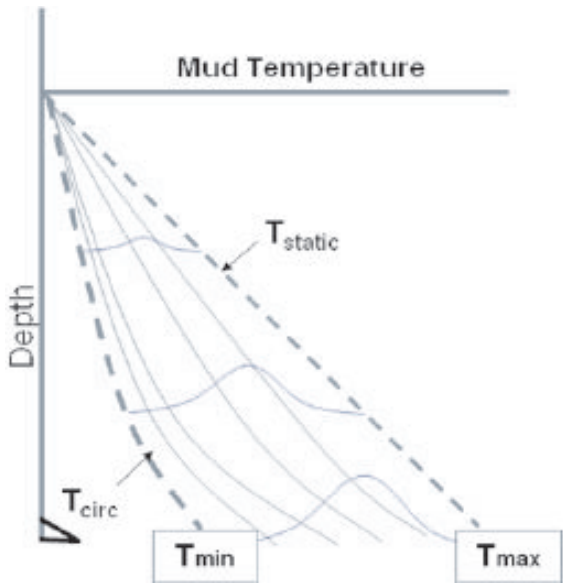


Fig. 6. Distribution of subsurface mud temperatures

Probabilistic assessment of the scenario of a casing shoe failure due to SCP and flow of hydrocarbons into upper formations is performed by testing of hypothesis on the means of two normal distributions with unknown and unequal variances [17]. Consequently, the distribution of differences of down-hole pressures due to SCP_{max} and Casing Shoe Strengths are obtained. In the case study well’s B annulus, although the mean value difference is – 1.02 ppge, still 28% risk of subsurface well integrity failure has been calculated (Fig. 7) [4].

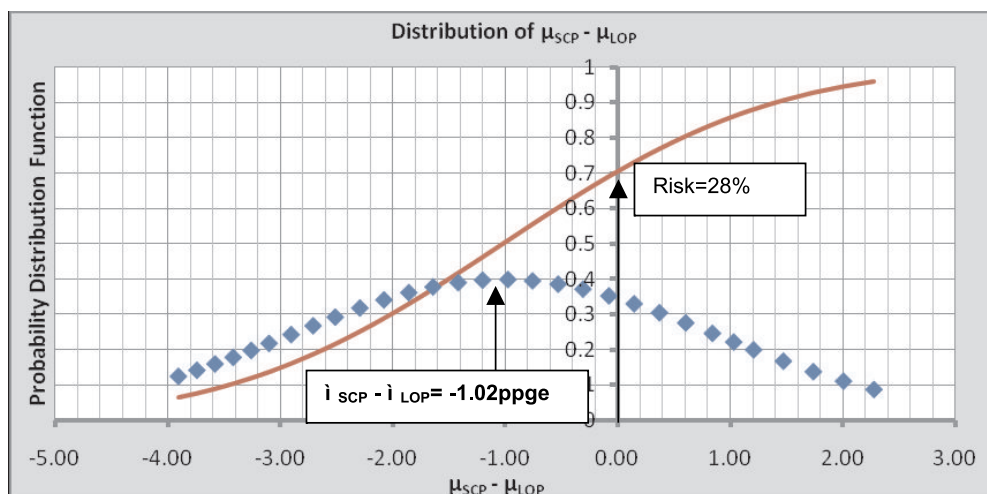


Fig. 7. Risk calculation by hypothesis testing on two population means

5. CONCLUSION

The study addresses environmental impact of wells affected by sustained casing pressure that may result from well integrity failure. Failure of the casing head integrity would result in air emissions, while the casing shoe failure would lead to gas migration in the outer annulus and possible pollution of underground source of drinking water or surface gas emissions. Results of the study are summarized as follows:

1. Present regulations specify severity of SCP based on testing with no quantitative analysis of the tests.
2. Present assessment of risk resulting from SCP is arbitrary with no analytical support.
3. A new method proposed in this study estimates maximum gas emission rate resulting from casing head integrity failure.
4. An alternative criterion for well integrity loss due SCP is proposed – casing shoe failure in the affected annulus. It is shown that the criterion may be more restrictive than the surface-failure criteria specified in present regulations and guidelines.
5. A new probabilistic approach is proposed to estimate risk at the casing shoe failure caused by SCP.
6. An algorithm and software has been built to compute the risk; in the example well affected by SCP the risk of the casing shoe failure is calculated as 28%.

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