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LEAKAGE BEHIND CASING

By

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SUMMARY

Achieving zonal isolation by cementing annulus space between casing and well bore is an important job in many oil wells. Gas leakage in the annulus has been recognised as a major completion problem in the oil well. A successful cement job results in complete zonal isolation on a permanent basis. To achieve these goals, various factors such as well security, casing centralization, effective mud removal, and gas migration must be considered in the design. The design of the cement must be such that it prevents micro-annuli formation, stress cracking, corrosive fluid invasion, fluid migration, and annular gas pressure. However, permanent solutions to gas leakage has not emerged and gas leaks during and after the cement is set.

In this thesis work attempt has been made to deal the fluid leakage behind casing in two levels, firstly, revealed gas migration mechanism and, secondly, analytical modeling of cement sheath failure by internal and rising temperature.

Several theories have been proposed regarding gas migration. In chaper 2 some probable physio-mechanical phenomena responsible for fluid migration in the cemented casing have been described. During cement setting and hardening gas migration is attributed to ineffective hydrostatic head, fluid loss during cementing, and the differential pressure occurrence due to the gelation. Micro annulus is attributed to the cement inability to form a good bond with the casing. Cyclic pressure and temperature variations during production also lead to the debonding or tensile failure or stress crushing of the cement causing gas migration. Gas leakage may occur years after production has ceased and well has been plugged and abandoned (P&A). Explanatory mechanism includes channeling, poor mud removal, shrinkage, and high cement permeability.

In chapter 3 efforts have been made to describe the case studies regarding zonal isolation. Case 1 describes the specialized cement design and placement procedures to mitigate casing vent flows (type: improve plan to avoid problem). Case 2 depicts a new cementing approach to improve and provide long term zonal isolation. Case 3 is related to the development of a methodology to evaluate the gas migration in cement slurries (type: predicting problem before it arises).

The stress in the cement is strongly connected with temperature and pressure, as well as lithology and in-situ stress. In chapter 4 an attempt has been made to quantify the cement failure as a function of down hole conditions and geometry and to define optimum mechanical properties to sustain the induced stresses. Analytical modeling has been done on the basis of plane strain in thin wall condition. Expressions for total stresses (hoop stress in casing, hoop stress in cement, and far field stress) are used to analyzed the cement integrity based on the case study well parameters of the Kristin Oil Field of Norway, Well R-3H (chapter 5). As this oil field is HTHP type, conventional cement is found not withstanding the stresses. In most of the situation tensile failure is the mode of failure, in some cases stress crushing and debonding. Improving the elasticity of cement or it's flexural and tensile strength appeared to be an elegant solution to prevent cement failure (debonding, radial craking, and stress crushing). In addition, improvement can be

made using high grade casing pipe (high Young's modulus, low Poisson's ratio). In reality a thick wall high grade (Q-125, SM-125) casing program has been selected in the Kristin Oil Field. The results of this study show the relevant dependency of stress principles with differential well temperature, pressure and field stress, Young's modulus, thickness, and diameter of casing and cement sheath are also important.

CONTENT

1. Introduction:

Achieving zonal isolation by cementing annulus space between casing and well bore wall is an important job in many oil wells. Cementing of the annulus may take place during drilling stage of the well bore or completion of the well or plugged and abandoned (P&A) phase. While cementing the annular space behind several casings strings or whole casings in the well may be cemented properly in place to get a hydraulic seal. Despite the efforts to get good zonal isolation, migration of formation fluid in the annulus takes place. Migration implies here the entry of formation fluid from the formations pores into annulus behind casing due to a pressure imbalance at the fluid-bearing formation face, followed by upwards migration of the fluid in the annulus. The fluid flows to a lower pressure zone or possibly up to surface. Among the formation fluid, gas migration is in the annulus behind the casing has been recognized as a major problem because it can leads to the blowout (danger to human and drill rig safety) and contamination of ground water (environment hazard). Gas migration has also been termed as gas communication, gas leakage, annular gas flow, gas channeling, and flow after cementing etc.

Gas migration phenomena can be caused by various factors and can take place at different time period. It is worthwhile when dealing with gas migration to classify problems into two distinct groups, "primary" and "secondary"[1]. The former can be defined as those which are related to aspects of the actual cementing operation i.e. slurry characteristics, displacement mechanics, hydrostatic pressures. Typically "primary" gas migration occurs within a few hours or, at most some days after the cementing operation. The main cause for primary type of problem is loss of hydrostatic head on the formation. It has been observed[1] that pressure in a column of cement actually decline shortly after cement placement. This pressure decline is attributed to a combination of gelation, fluid loss and chemical contraction phenomena. "Secondary" gas migration is, by nature, a gas leakage has little to do with the cementing operation since it occurs weeks, months or even years later. It may be caused by mechanical and thermal stresses which compromise the integrity of hydraulic bond or the integrity of the cement materials.

Gas migration/leakage is associated with the gas flow through the cemented annulus portion of the well bore. Mechanism of gas flow through annulus has been attributed to gas percolation, gas migration, gas flow along the interfaces between cement and formation or cement and pipe depending upon the various physical aspects of cementing practices, formation characteristics, hydrostatic situations, cement slurry properties etc.

This thesis work is aimed to study physical mechanism of gas migration in the cemented casing based on the work done by universities, research institute, Oil Company and Service Company i.e. basically on literature review. An analytical study shall be made on the effect on cement-casing bond by change in pressure and temperature. Effect shall also be made to outline accepted procedures aiming to reduce gas migration. Case-studies regarding gas migration prevention/remediation shall be used as necessary back ground for all thesis tasks.

2. Gas Leakage after Cementing:

Cementing of the annuli between casing and formation in the oil well is the adopted procedure to obtain hydraulic seal. Casings are cemented using water-cement slurries. These are pumped down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden. Casing and rock are prepared by careful conditioning using centralizers, mudcake scrapers, and so on. During placement, casing is rotated and reciprocated to increase the sealing effectiveness of the cement grout.

Gas leakage in the annulus behind the casing has been recognized as a major completion problem in the oilwell. Despite efforts of many companies and individual researchers, the problem has remained unsolved. Gas migration in cement occurs during and after the cement is set. It has been found that even when leakage rate is small, excessive pressure can build up if the annulus is not vented. In some cases, the gas leakage rate is great enough to warrant connecting the annulus to a gathering line. In deep holes, leakage resulting from dehydration, gelling, or bridging of cement or mud in the annulus can cause a pressure build up behind the production and intermediate casings or behind the liners.

Several theories have been proposed regarding gas migration during cement setting and hardening. These theories attribute the gas migration to ineffective hydrostatic head, fluid loss during cementing, and the differential pressure occurrence due to the gelation which precedes the cement setting. This differential pressure causes gas to migrate into the pores of the cement gel structure. Micro-annulus is attributed to the cement inability to form a good bond with the casing. Micro-fractures are formed between cement and formation and within cement itself. Casing centralization, use of scratcher to clean mud cakes, and use of fluid spacers were some of the early ideas employed to solve the gas channeling problem, however, the application of these methods helped to reduce gas channeling but not eliminate it. The two main reasons for gas channeling through a cemented annulus are the mud cake that remains between cement and the permeable formations provides a weak zone for the passage of water and gas, resulting to failures in cement job, and, the inability of cement to hold the high fluid pressure at the period of its initial set which may cause water accumulation, resulting to micro fracture within the cement body.

During the production phase of the oil well, cemented casing together is usually subjected to cyclic pressure and temperature variations. Change in casing pressure during pressure testing and thermal shocking in cyclic steam operation are some examples of this type. Set cement sheath may be subjected to stress failures thereby causing the gas leakage. For commonly used tail cement, rock mechanics type of tests is obtained to get detailed stress-strain behavior that helps to study the stress failure of cement sheath.

Oil and gas wells can develop gas leaks along the casing years after production has ceased and well has been plugged and abandoned (P&A). Explanatory mechanism includes channeling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing.

Field survey has shown that even when the most up-to-date cement types and techniques are used, leakage can and will occur in a significant number of cases[6]. It has also been observed that majority of well leakage occurs within a few withdrawal/injection cycles. The prime causes might be related to the "primary" type of problem and/or low cycle fatigue of materials, which brings failure due to the result of operating at a stress level that is too near the material's ultimate limit.

Oil well behavior that is observed in practice in relation to delayed gas leakage can be rationally explained by the following conceptual model[2]. This model, assuming good quality cement operation, tries to explain the followings:

- Generally there are no open circumferential fractures detectable after typical good quality cement job ("good bond" is observed on the log traces).
- Such fractures develop over time and with well service.
- Even in cases where bond appears reasonable over substantial sections of the casing, gas leakage may be evidenced some years or decade later.
- The process is invariably delayed; thus, there must be physically reasonable rate limiting processes.
- The gas often appears at surface rather than being pressure injected into another porous stratum encountered in the stratigraphic column.
- The presence of surface casing provides no assurance against gas leakage.

2.1. Gas Leakage Model due to Shrinkage: (Main source: Reference-2)

Figure 2.1.1 shows the effect of shrinkage on near well bore stresses. Initially, cement pressure ($\gamma_{c.}z$) is higher than pore pressure (p_o) but lower than lateral minimum stress (σ_{hmin}). Cement set occurs and a small amount of shear stress develops between the rock and the cement, then, hydrostatic pressure in the cement is no longer transmitted along the annulus. Thereafter, even minor shrinkage (0.1-0.2%) will reduce the radial stress (σ_r=σ'_r+p_o) between cement and rock because rock is stiff (4-20GPa for softer rock), and small radial strains (0.001-0.003) cause relaxation of σr, and increase in tangential stress σ_{θ}. A condition of p_o>σ_r (σ_3) is reached; i.e. the hydraulic fracture criterion. A circumferential fracture perpendicular to σ_{hmin}, typically no wider than 10-20 μ_m, develops at the rock-cement interface.

A thin fracture aperture is sufficient to appear as "loss of bond" in a geophysical bond log. Because in situ stresses are always deviatoric (e.g. $\sigma_{hmin} \neq \sigma_{hmax}$), bond loss will usually appear first on one side of the trace, or on two opposite sides (direction of σ_{hmin}). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m.

A zone of $p_o > \sigma_r(\sigma_3)$ can extend for cosiderable heights. Nevertheless, this is still not a mechanism for vertical growth. To understand vertical growth, consider figure 2.1.2, where a hypothetical case is presented. The static circumferential fracture length L is filled with formation water of density γ_w, giving a gradient of about 10.5 kPa/m for

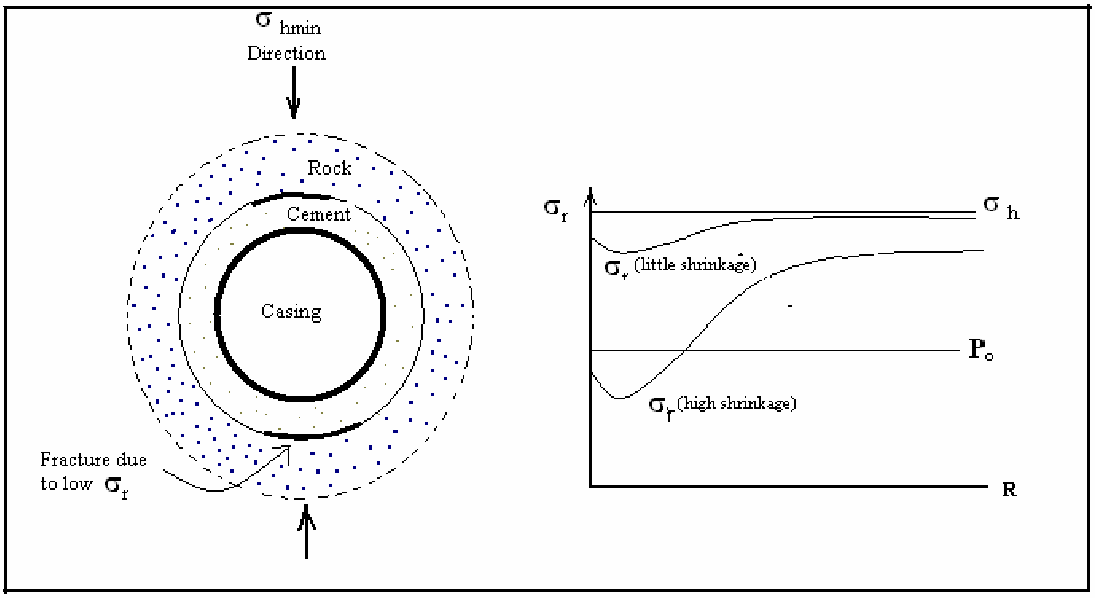

Figure 2.1.1: Radial Stresses and Circumferential Fractures. (after reference-2)

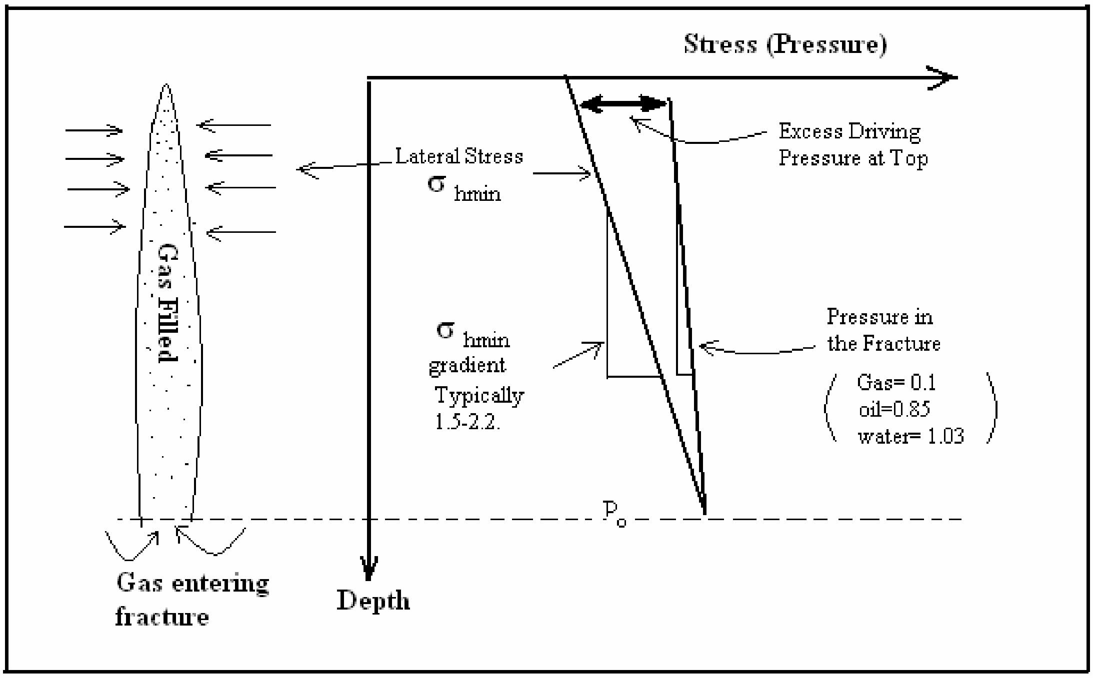

Figure 2.1.2: Fracture Driving Pressure from Gradient Differences (after reference -2).

typical oilfield brine, but the gradient of lateral stress ((σ_h/σ_z) is generally on the order of 18-24 kPa/m. This means that if the fracture contains a fluid pressure sufficient to just keep it open at the bottom, there is an excess pressure at the upper part approximately equal to L(21-10.5) $\approx$ 10 kPa/m. Thus, because of the imbalance between the pressure gradient in the fracture and the stress gradient in the rock, an inherent fracture propagation force is generated that tends to drive the circumferential fracture upward.

Cementing a casing leads not only to the development of a cement sheath, but the cement paste also slightly penetrates the interstitial space in the surrounding rock (a few grain diameters deep for typical sandstone). This reduces the permeability substantially, and because of capillary exclusion effects associated with two-phase flow and the reduced pore throat diameter arising from cement particle invasion, gas flow into the circumferential fractures is almost certainly through diffusion. This means that when the fracture is small, the rate of gas influx is modest. However, as the fracture grows in height, the contact area with surrounding sediments increases, and eventually, the gas diffusion rate is large enough to lead to continuous but slow gas leakage.

In the fracture, once solution gas saturation is achieved, free gas at the top of the fracture develops. The gradient in gas is less than 1 kPa/m (rather than ~ 10.5 kPa/m for water) so there is an even greater excess driving pressure at the upper tip. In addition, this gradient effect tends to favor driving the liquid in the fracture back into the formation, though slowly, and fracture becomes more and more gas filled. Thus, there is a self-reinforcing process: the greater the vertical height of the fracture, the greater the excess driving force at the tip. The fracture grows vertically upward, and eventually leads to gas leakage behind the casing at the surface. It will migrate up around the outside of any casing strings at higher elevations because the excess pressure that can be developed at this stage is large enough to fracture even excellent bond. However, it may take so long for the gas to get to surface (sometimes decades). Probable reason may be the: gas migrate to surface through a circumferential fracture perhaps only 10-20 μm thick extending over only a limited part of the circumferential of the rock-cement interface. Fracture aperture develops between p_f and σ_3 when the pressure acts to maintain it open, but because the rock and cement have elastic stiffness; they act to severely restrict the aperture. Thus, there are at least two rate-limiting aspects to gas evolution at the surface: diffusion rate of gas into the fracture, and the low "hydraulic conductivity" of the circumferential fracture arising because of its narrow aperture.

Why does the fracture grow so slowly? When the micro-annular circumferential fractures are not connected and are short, the excess pressure at the tip is small. Also, if the casing pressure is large because of production pressure, this leads to a small outward flexure that may be enough to maintain the fissures closed. As the production pressure declines with time, the fissure will tend to open more because the casing is less pressurized. Also, fracture growth in the vertical direction is undoubtedly aided by pressure and thermal cycles.

Nevertheless, it is common for gas bubbling at the surface to be noticeable only years and sometimes decades after P&A. over time, the effective fracture length increases, and this leads to the driving pressure increases discussed above. Because the velocity of a fracture is a very strongly non-linear process that is positively coupled to the driving pressure, it probably takes years for diffusion processes to lead to a condition where growth starts to accelerate. However, once acceleration begins, the fracture length increases, and complete upward propagation is fast, limited only by the rate at which fluids can enter the fracture at depth and flow to the trip. Thus, before P&A, a cement bond log may show that the well is in good condition, yet this is no guarantee that, years later, leakage will not occur.

As the fracture rises, the condition that the pressure in the fracture exceeds the pore pressure in the surrounding strata will arise. This will lead to flow from the fracture out into the strata. If this flow is unimpeded, it will occur and the fracture vertical growth will terminate. Now, a condition exists where gas and liquids are entering the wellbore region behind the casing and leaving it at a higher elevation. This is a loss zonal seal, and could have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination. It can also have positive environmental effects. Properly executed.

Yet, despite the existence of permeable zones, gas is still observed at the surface, and also as deep-sourced gas in shallow groundwater aquifers. The reason is probably that the cement paste in the pores of permeable strata acts to exclude gas by capillary effects along the entire length of the stratigraphic column (it take a large Δp to overcome surface tension effects in small pores). This means that gas must leave the fracture mainly by liquid-phase diffusion. So, it seems that in leakage cases the flow rate from depth simply exceeds the diffusion bleed-off rate at higher elevations, leading to the excess appearing at the surface. Even if no gas appears at the surface, it is no guarantee that the well is not leaking. In fact, the common occurrence of household water sources being charged with deep-sourced gas is clear evidence that there are many cases of leakage where the gas simply enters the water aquifer, and may never bubble around the casing.

2.2 Gas Leakage due to Cyclic Pressure Variation:

The objective of cementing the annulus, which is present between the casing and the formation, is to provide zonal isolation of the formations that have been penetrated by the well bore. No fluid communication should develop during the life of the well among these various formations, whether they are saturated with water, oil, or gas, and the surface. However, long term annular influx problems usually experienced even in situations where the cement was properly placed and initially provided a good hydraulic seal. The disappearance of zonal isolation with time is observed. This disappearance is revealed, for example, by a gas migration problem that was not initially detected, or by the fracturation of a wrong zone during a stimulation treatment. The loss of the cement bond log response with time also creates some concern about the quality of the isolation. Long term annular influx has long been believed to be caused by either sheath failure or hydrostatic pressure loss in a channeled (bypassed) mud column after the weighting material ha settled out of the drilling mud[5].

Studies[4, 5] shows that stresses induced in the cement from the variation of down hole conditions are the cause of this damage. Various processes can result in a variation of down hole conditions in a cased section of a well bore. These processes include the drilling of the well bore, the perforation of the casing, and the stimulation and production of the reservoir. Drilling involves a variation of pressure, if the mud weight has been changed to drill the next section and a temperature increase of the cased sections when the mud, which has been heated by the formation being drilled, returns to the surface via the annulus. Associated with the drilling process are the various pressure increases that result from integrity and leakoff tests. Pressure increase during perforation follows the firing of the guns, and, although it is applied dynamically to the casing (cement is more resistant to dynamic loading than to static loading), can lead to cement damage. The amount of pressure increase during perforation is significant. The increase of well bore pressure during hydraulic fracture stimulation is more damaging to the cement sheath because the fluid injection lasts from minutes to hours.

Increase of pressure and temperature during production mainly concerns the near-surface casing sections, where surface pressure is increased from about atmospheric pressure to production pressure, and temperature is increased to about, in some cases, down hole temperature. The pressure variation usually concerns only the production tubing and, therefore, does not affect the cemented sections, unless a gas migration problem results in an annulus pressure increase. A temperature increase also can lead to pressure increase in the annuli following gas expansion, if the annuli are saturated with gas. Pressure decrease during production mainly affects the bottom of the hole where down hole pressure, which is controlled by the production rate, decreases from formation pore pressure to down hole production pressure.

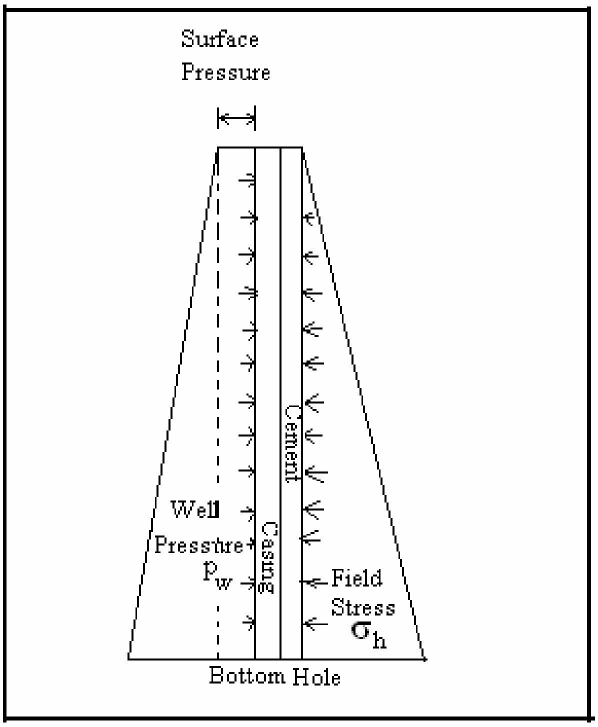

Figure 2.2.1 Pressure situation in the borehole.

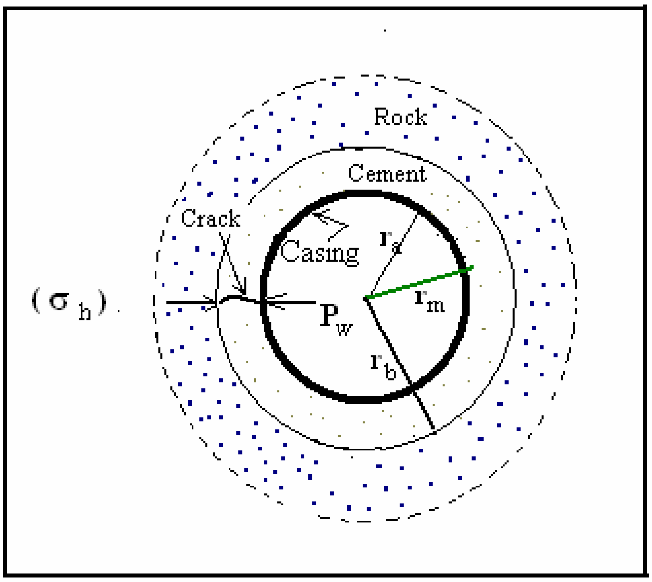

Figure 2.2.2 Tensile failure in cement sheath due to differential pressure.

Assuming that the cement column represents a physical force (not a hydraulic pressure) against the outer casing surface, the total internal casing pressure (and the differential pressure across the casing wall thickness) becomes the sum of the surface pressure plus the hydrostatic pressure of the casing fluid. Depending on the casing fluid density and depth, these differential pressures can range from surface pressure to as high as 20,000 psi at the bottom of the hole[5]. This implies that cement sheath failure caused by excessive casing test pressure generally should occur somewhere in the bottom one-half to three quarters of the casing string, creating zonal isolation loss over those interval. If excessive casing test pressure are conducted while the cement is gelled but not set, casing expansion frequently will create a large micro annulus between the casing and cement sheath, creating a flow path to the surface.

Loading other than changes of well bore pressure and temperature, can be applied to the cement sheath during the life of the well. For example, an increase of the pressure on the external surface of the cement represents a situation where the formation loads the well bore because of creep. Far-field minimum stress changes can also occur following a change of reservoir pore pressure or reservoir temperature.

Generally, the presence of stress cracks in the cement sheath is not a problem while the casing is expanded as long as the cracks do not extend into the formation at a well-bonded interface. When the casing relaxes during pressure release and/or cooling, the cracks open sufficiently to permit annular flow.

2.3 Gas Leakage due to Temperature Variation:

Downhole deformations can occur as a result of thermal stresses (cement hydration, wellbore cooldown treatments, steam injection, cold fluid injection). Exposure of steel causing to excessive temperature increase causes diametrical and circumferential casing expansion. This circumferential force creates a shearing force at the cement/ casing interface, causing failure at the cement/casing interface or radial fracturing of the cement sheath from the inner casing surface to the outer casing (or borehole) surface. Long-term annular influx due to temperature generally occurs following excessive temperature changes resulting from excessively high producing temperature or steam-injection temperature.

In some wells[5], annular surface pressure becomes evident only after the well has begun producing. This phenomenon is observed where surface flowing temperature are excessively high or in steam flood injection wells. Though annular flow (gas or liquid) is measured and sampled at the surface, it is possible that flow originate in zones considerable distance above the primary producing zone. This implies that cement sheath occurs in the upper one-fourth to two-thirds of the casing string when failure is caused by excessive temperature change. In the case of shallow steam flood injection wells cement sheath failure appears to occur over the entire cemented interval. This type of cement sheath failure is believed to result from sheath stress cracking caused by diametrical and circumferential casing expansion from excessive temperature increases.

Temperature changes in a flowing well can create significant casing –diameter increases. This expansion is cubical (volumetric). The coefficient of cubic expansion of a solid is approximately three times the linear coefficient. The axial stresses created by the increasing casing outer diameter create stress cracks in the cement sheath much as the excessive inner casing pressure does as described in the chapter 2.2. This stress cracks result from the cement failure in tension, not in compression[5]. Contrary to the pressure, the changes in casing temperature do not occur near a producing zone but toward the surface, where significant differential temperature can occur (e.g., surface flowing temperature less the normal geothermal temperature).

Generally, the presence of the stress cracks in the cement sheath is not a problem while casing is expanded (e.g., while the well is flowing or during steam injection) as long as the cracks do not extend into the formation at a well-bonded interface. When the casing relaxes during cooling, the cracks open sufficiently to permit annular flow. Where pumping low-density, low-compressive-strength cements is possible, the cracking problem can be practically eliminated.

2.4 Shear and Hydraulic Bond Strengths:

In a well bore, shear bond and hydraulic bond are the two forces to be considered for effective zonal isolation along the cement/casing and cement/formation interfaces. Shear bond mechanically supports pipe in the hole, and is determined by measuring the force required to initiate pipe movement in a cement sheath. Hydraulic bonding blocks the migration of fluids or gas in a cemented annulus and is usually measured by applying pressure at the pipe/cement interface until leakage occurs.

At no stress change condition in well bore, hydraulic bonding is of greater significance than shear bonding because the cement composition for most jobs will provide adequate mechanical support to hold pipe in place. But when stress condition is affected by change in pressure, temperature, and field and mechanical stresses, shear bonds hold much significance.

2.4.1 Bonding of Cement to Pipe:

Shear, hydraulic, and gas bond strengths are directly affected by the surface finish of the pipe against which the cement is placed. Where pipe/cement bonding is critical, a resin-sand coating applied to the outside of the pipe will improve the bond as well as the resistance to gas migration. On equivalent pipe finishes, oil-wet surface provide the poorest bond. Generally, the rougher and drier the surface of the pipe, the better the bond.

Other factors[11] influencing casing/cement bonding is the direction is the direction in which pressure is applied and the length of time pressure is held on the bonded interface. During the setting of cement, the heat of hydration can produce an effect similar to internal pressuring of the casing and cause expansion of the pipe. Normally, heat begins to build up inside the casing as the cement hydrates and takes its initial set. After the cement sets, its temperature decreases, causing the casing to contract. This expansion and contraction places additional stress on the casing and cement sheath, which can decrease the shear and hydraulic bond strength.

Hydraulic bond failure is a function of time, cement properties, applied pressure, and viscosity of the pressuring medium. Investigation[11] has shown that the rate of bond failure with water ranges from 1.125 to 1.250 ft/min. Normally, pressure from gas which has a lower viscosity causes bond failure to progress up the pipe faster than pressure from water, oil, or mud. Vertical bond failure will normally occur 30o each side of the pressure-application point when there is uniform cement can cause bond failure at the weakest plane (which could account for communication in multiple-string tubing less completions). The intrusion of casing attachments such as collars, centralizers, scratcher has little influence on hydraulic or gas bond failure pressure.

In considering pipe/cement bonding, the following points are noticeworthy[11]:

1. A change in internal pressure on the casing will cause a corresponding change in hydraulic and shear bond strength. If the casing is closed in while the cement is setting, the heat of hydration causes a pressure buildup that lower the strength of the bond and can readily create a micro annulus through which gas can migrate easily.
2. Hydraulic and shear bond strengths increase with surface roughness.
3. As the viscosity of the pressuring fluid increases, the pressure increases, hastening failure or communication of fluid where the pipe and cement come in contact.
4. Oil-wet pipe surfaces reduce the hydraulic shear strength of the cement/ pipe bond.
5. Hydraulic bond failure is a function primarily of pipe expansion or contraction.

2.4.2 Bonding of Cement to Formation:

The bond between the cement and the formation is what normally determines whether there will be gas or fluid communication in the annulus. Cement sets better against one coated with mud cake. The following general statements[11] apply in cement/formation bonding.

1. A good hydraulic bond to the formation depends on intimate contact between the cement and the formation.
2. A thick mud layer at the cement/formation interface greatly reduces hydraulic bonding.
3. Higher bond strengths can be expected on more permeable formations if the mud cake has a uniform thickness.
4. The bond strength ultimately attained on a dry formation or a formation free of filter cake will approach or exceed the formation strength.
5. Failure to remove mud can be more detrimental to formation bond than to pipe bond.

2.5 Mud Cake Buildup and Mud Channeling:

The existence of mud cake at the formation wall is the primary problem that leads to the weaks bond between cement and formation. Despite use of spacers like acid mud, pure water, the complete mud removal is problematic. Mud cake remaining between the formation and the cement provides regions of weakness. These regions allow the passage of water or gas resulting to cement job failure. Results from several wells indicated that significant amounts of mud were bypassed below the cement top, and that the high gel strength made the made column movement more difficult.

Mud channeling occurs during the injection of cement slurry or displacement of cement by drilling fluids. This phenomenon occurs when there are differences in densities of the cement and mud, and it is dependent on the flow regime existent in the annulus and the mud viscosity. Cement job failures are also due to the channeling of the cement slurry as a result of off-centered casing. A thin mud prior to cementing reduced channeling. An increase in the annular pressure drop results to a decrease in channeling[9].

Incomplete mud dispalcement can leave a continuous mud channel in the annulus, thereby favoring interzonal communication. Proper mud removal techniques to minimize gas leakage were outlined as early as 1973 by Carter et al. They are related to the following[10]:

- Mud conditioning,
- Casing centralization,
- Casing movement, namely rotation and reciprocation, during mud circulation and possibly during cement placement,

- Choice of proper preflushes and spacers, in terms of compatibility with mud and cement, density, rheology, fluid-loss control, and solids control,
- Choice of proper fluid volumes (contact times), and
- Determination, by a computer simulation, of adequate flow rates according to down hole conditions, with preference to high rates and turbulent flow.

3. Good and Bad Experiences in Zonal Isolation Job:

Riview of three case studies of different type have been presented.

Case 1 is suggesting a practical method of how to solve annular pressure build up problem solved in the field.

Case 2 is of improving plan to avoid gas migration.

Case 3 is predicting gas migration before arises type.

They are presented in the same structure case wise under sub heading 'The Problem', 'Why and how', 'Problem Characters', 'Solution', and 'Gained Experiences'.

3.1 Case 1. Specialization Cement Design and Placement procedures Prove Successful for Mitigating Casing Vent Flows (CVF) —Case Histories[16]:

3.1.1 The problem:

Mitigation of Casing Vent Flow (CVF) on producing and abandoned wells. Petroleum Industry commonly encounters annular gas pressure on cemented casing annuli. This condition is often refered to in different terms based on the local interpretation of the problem. Terms such as sustained annular-casing pressure, annular gas pressure, and casing vent flows, or annular gas flows refer to the same general problem.

3.1.2 Why and how:

CVF problems exists when gas pressure builds up in casing-by-casing annuli. When annuli are shut-in, the gas pressure can build to a significant amount. CVF may cause environmental concerns relating to potable water sands or cause shallow drilling hazards on another well or adjacent new wells.

3.1.3 Problem characters:

The amount of gas pressure build-up can vary from slightly above atmospheric pressure to that of near deep-gas reservoir pressure depending on the gas source and flow path from the source to the surface. Also, the amount of bled from the annuli can vary from a very slight flow to 1000's of standard cubic meters per day. CVF's can be caused by several factors. However, the industry has recognized the following factors as the main causes:

- Poor mud displacement in the primary cement placement.
- Cement sheath failure, resulting in sheath cracking.
- Gas migration through the setting cement creating gas channels in the set cement.
- Low cement top.

CVF can also reoccur after initial squeeze-cementing job, though, the job showed the indications of success. Investigation of the wells having reoccurrence of CVF indicated that some of the original cement slurry did not set as intended because of the following reason:

- Contamination of the neat cement before mixing.
- Formation fluid influx after placement.
- Cooler than expected well temperatures.
- Contamination of neat cement during mixing.
- Development of Thaumasite (it is caused by the presence of sulfate and carbon dioxide in the slurry or setting cement at low temperature $<20^o$)

3.1.4 Solution:

Based on Laboratory results and post-job reviews of failed remedial attempts, the following guidelines are recommended for preventing CVF:

- Use of chemical wash ahead of the treatment to help remove the presence of sulfate and carbon dioxide in and near the well bore. This help prevent Thaumasite development. The most effective solution to sulfate attack has been the use of pozzalan additives in the slurry. Pozzalan lower the permeability of the set cement and transition tome. Low permeability and short transition time prevent the invasion and influx of formation fluid.
- Use a permeable-sealing fluid ahead of the squeeze cement with expansion additive slurry. This fluid will enter the formation and form a gel that blocks the formation's permeability and near-well bore micro fractures. Polymer gels can enter micro fractures in a failed cement sheath or dehydrated mud cake, further improving the seal of a gas source zone. Cement expansion additives help prevent gas migration and increase bonding to pipe and formations.
- Use the formulated squeeze slurry, which has a short transition time and Thaumasite-prevention.
- Use mechanical set-cement retainers to help provide better isolation. Typically, mechanical set retainer seal better because a higher setting force can be applied on the sealing element. Also, mechanical tools set slower than wire line tools, which allow the packer element to compress further than with wire line setting device. This should result in a better isolation seal in old or corroded casing.
- Attempt to obtain a squeeze pressure greater than the pressure in adjacent source zones. Unless other factors present themselves, the general guideline is to apply at least 5 to 7 MPa on shallow formations and 10 to 15 MPa on deeper source zones. This application helps ensure that the final squeeze pressure is above the source

zone's pore pressure. By obtaining a higher pressure in the cement slurry, the chance of formation fluid influx into the setting cement can be reduced.

Case Histories:

In October of 2001, 20 wells were plugged and abandoned with the improved solutions. Results from these squeeze operations are contrasted to a year-2000 abandonment program on eleven wells. The Year-2000 abandonment program did not use the improved solutions outlined in this section. The requirement before starting a new squeeze job is to obtain a 7-MPa squeeze pressure.

The 2000 Celtic Field Abandonment Project: Across eleven wells (three zones per well) the following was achieved:

- On five of the eleven wells (45%), two successful squeezes were executed in only one day.
- On the remaining 55% of the wells, only one or less squeezes per day could be executed because of the long hesitation period to achieve to squeeze pressure.
- On six of the eleven wells, the production zone was squeezed successfully on the first attempt (55% success).
- The average number of cementing days to achieve the abandonment objective was 3.3 days per well.
- None of the eleven wells had CVF's pre- or post-treatment.

The 2001 Celtic Field Abandonment Project: Across twenty wells (three zones per well) the following was achieved:

- On sixteen of twenty wells (80%), two squeezes were executed in only one day.
- On the remaining 20% of the wells, only one or less squeezes per day could be executed.
- On fourteen of the wells, the production zone was squeezed successfully on the first attempt (70% success).
- The average number of cementing days to achieve the abandonment objective was 2.5 days per well. Of these twenty wells, eleven had CVF's. After incorporating the improved solutions presented, 7 of the wells had immediate shutoff of the CVF. Buildup analysis on the remaining four wells indicated flow dissipation.

For the 2001 project, 1.08 attempts per zone were required to achieve a successful squeeze. The typical industry rate for the field is 1.4 attempts per zone.

3.1.5 Gained experience:

Improved remedial cementing solutions were developed to help to help prevent the development of thaumasite and to help obtain a gas-tight barrier of source zones.

Results from executing these improved solutions show that CVF can be successfully mitigated and the improved solution can be executed in a shorter period of time than previous operations.

3.2. Case 2. A New Cementing Approach to Improve and Provide Long-Term Zonal Isolation[17].

3.2.1 The Problem:

Designing of a cement system, which can be used to cement solid expandable tubular (SET) in a carbonate field in southern Saudi Arabia.

3.2.2 Why and how:

Milling the cemented SET could introduce problems to conventional cement. Conventional cement can fail due to pressure and temperature cycles. On the other hand, casing corrosion is another challenge. Poor cementing placement practices, set cement matrix properties and cement losses are significant factors that are contributing to the corrosion problem. Consequently additional costs are enforced when workover rigs are mobilized.

3.2.3 Problem characters:

Smart completion technology is widely used in Saudi Arabia to aid in increasing oil production by monitoring the progress of lateral producers. The use of expandable tubing reduces the cost of the well by eliminating operations associated with conventional tubing.

Well “A” of the Shu’aiba Reservoir located in the Eastern Rub’Al-Khali of Saudi Arabia was completed as a horizontal well and subsequently re-completed as multilateral. SET technology have been used which is 900-ft long, $5^{1/2}$ –inch diameter, placed horizontally in a $7^{1/2}$-inch drilled hole with a 9000-ft depth. SET have been expanded to a larger diameter equal to 6.147 inches.

Expansion of SET lead to stresses induced in the tubing, the formation, and the cement sheath. As conventional cement is less elastic, shrinks by 3 to 4% during hydration, has high compressive strength and permeability, and fails mostly in tension, the effectiveness of the cement in maintaining long-term zonal isolation is critical. To overcome problems associated with regular cement, a new flexible and expandable cement system to prevent micro annulus formation was necessary.

3.2.4 Solution:

The new advanced cement system (NACS) represents a dry blend of Portland cement, flexible particles, an expanding agent and other materials added to enhance the properties based on well conditions. The objectives of the study was (i) perform lab studies to evaluate the new cement system for potential use (ii) Design and apply the new system in the field, and (iii) evaluate the treatment based on field data.

The New Advanced Cement System (NACS):

The NACS is based on particle volume fraction (OPSD = optimized particle size distribution) technology. The OSPD technology is a new approach to cementing using simple products in water-reduced slurry by applying the concrete technology in oilfield application. The properties of the set cement cured under temperature and pressure simulating the downhole conditions is represented in terms of flexural strength, compressive strength, elastic properties (Young's modulus and poison ratio), permeability and volumetric changes during hydration.

Applying OPSD technology reduces the set cement permeability (conventional cement – 0.1 mD, NACS – 0.01 mD). The conventional cement shrinkage is about 3-4%, whereas NACS does not shrinkage. An expansion test performed at the down hole condition proved that the NACS expands. The linear expansion at 185^{o}F and 3000 psi is about 0.65%.

Table 3.1 Elemental analysis of regular and NACS cements (Taken from the Reference):

Element	Regular Cement	NACS
Ca	36.62	25.95
Si	8.69	10.53
Fe	2.86	1.84
Al	1.2	1.4
Mg	1.04	1.10
S	0.55	0.62
Ti	0.12	0.11
Mn	0.02	0.03
Sr	trace	trace

Another important advantage of the NACS is its ability to provide better flexibility characteristics along with expansion without causing internal failure. Flexibility is achieved by the relative decrease of the Young's modulus values compared to conventional system. The magnitude of the modulus is inversely proportional to the concentration of the flexible additives. A system with 1X%bvob flexible material has half (600,000 psi) the Young's modulus value than system without flexible material (1,200,000 psi). Flexible material reduces the compressive strength but increases the elasticity.

Acid solubility was conducted by placing cement sample in 5wt% HCl solution. The NACS has less calcium and iron than the conventional cement, so it is more resistance to inorganic acids.

Case Study:

The Shu'aiba reservoir consists of reef, lagoonal, and deep-water carbonate accumulation. The oil column is overlain by a large gas cap, and underlain by an active aquifer. Most oil producers in the field were completed as horizontal wells. To increase oil production maximum reservoir contact (MRC) wells were drilled and some horizontal wells were re-completed as multilateral. Well "A" is one of them.

A new 6-1/8 inches mother bore was initiated at 6350 ft and drilled at the lower side of the original 6-1/8 inches hole. This new hole was under-reamed from 6-1/8 to 7-1/2 inches from the previous casing shoe (6249 ft) to 8 inches. Expandable liners were ran upto 6950 ft. When at the setting depth, water cleaning was done, and then a 10 bbl spacer and 28 bbl of NACS cement were pumped and displaced with 55 bbl water. Finally expansion process took place. Inflow and pressure test at 2000 psi were performed on the set cemented liner and showed no sign of leaks.

<u>Evaluation of Field Application:</u>

When the ultrasonic and the sonic tools are run in combination, we can determine the presence and type of a microannulus. In well "A", sonic tool reading indicative of average bond at various intervals was observed where the ultrasonic confirmed good cement bond.

In terms of the impact of the workover, the reservoir contact has been 1 to 5.8 km, and production rate has improved from an average 1.5 to an optimum rate of 5 MBOD. Water cut decreased from 7 to 2 vol% as a result of this operation.

3.2.5 Gained Experience:

Appropriate mechanical properties of cement can reduced potential cement failure and debonding. High compressive cement is not always the best solution whereas; the flexible cement is the appropriate approach. In this connection, the new advanced cement system (NACS) has been found usable in the cementation of solid expandable tubular (SET) because it is able to sustain stresses encountered during milling, drilling, and completion due to the following properties:

- It is ductile than regular cement; as a result, so it enhances cement resistance to stress cycling,
- Higher concentration of flexible material reduces the Young's modulus,
- It has low permeability and porosity than conventional cement,
- It expands after placement in order to enhance the bond between the casing and the formation
- It is more resistant to acid (HCl) than conventional cement.

3.3 Case 3. A Methodology to Evaluate the Gas Migration in Cement Slurries:

3.3.1 The Problem:

Searching for a methodology which can predict the fluid migration occurrence at particular well conditions, hence allowing the selection of the optimum cement slurry design, in order to assure the well life.

3.3.2 Why and how:

Gas migration represents 25% of the primary cement job failures. For this reason, studies have been done in order to evaluate several properties of cement slurry like fluid loss, permeability, static gel strength, and others. However, the study of this variable has not shown separately a method to prevent the gas migration and which of these properties of cement slurry have to be controlled to avoid such problem. Development of a methodology to prevent fluid (gas/liquid) migration in well cementing is in demand.

3.3.3 Problem characters:

One of the main problems in achieving zonal isolation for the life of well is fluid migration in the annular space after well cementing. The main factor preventing the fluid from entering the cement is the lowered hydrostatic pressure of cement column and the mud above it. This pressure must be greater than pore pressure of the formation and lower than fracturing pressure of the formation. The ability of the cement slurry to transmit hydrostatic pressure, that affects the total hydrostatic pressure of the annular column, is a function of the cement slurry gel strength. The higher the gel strength, the lower is the transmissibility of the annular hydrostatic pressure. When hydrostatic pressure is the same as the pore pressure and the Static Gel Strength (SGS) is not high enough, fluid migration can occur.

In recent years much attention has been given to fluid migration in well cementing. In spite of that, there are not any industry recognized standard methods (API or ISO) for evaluate fluid migration problem. For this reason, several methods and definitions have been misunderstood.

3.3.4 Solution:

A methodology has been developed to prevent fluid migration in well cementing, which consists of three steps: the first one is the evaluation of Flow Potential Factor (FPF) which predicts the severity of the problem. Then, the static gel strength (SGS) is measured as a function of time, obtaining the transition time of the cement slurry. Transition time is defined as the period from 100 SGS (fluid intrusion into gelled cement can occur) until 500 SGS (the slurry develops sufficient gel strength to prevent fluid migration). Finally, pressure reduction due to SGS verses time is simulated with Fluid

Migration Analyser (FMA), validating gas migration through cement slurry. Three wells were studied in Venezuela determining the FPF. The result of the study agrees with field experiences, based on quantitative measurements like transition time and FPF. This methodology allows selecting the optimum cement slurry design in a way that prevents industrial accidents and assuring the well life.

Experimental Procedure:

There are many parameters that are included in the evaluation of fluid migration. This methodology takes into account three of them, which are given below:

i) Flow Potential Factor (FPF):

The equation for pressure restriction due to static gel strength is:

$$\Delta p = \frac{SGS.L}{300.D} \qquad (3.1)$$

Δp: pressure restriction due to SGS, psi.
SGS: Static gel strength, lb/100 ft2.
L: Length of interval.
D: Hole diameter – Casing diameter, inch.

MPR: Maximum pressure reduction due to static gel strength (SGS= 500 lbf/100 ft^2 was found to be the gel strength required to prevent fluid percolation), and it is given as

$$MPR = \frac{SGS.L}{300.D} = \frac{500.L}{300.D} = \frac{1.67.L}{D} \qquad (3.2)$$

The ratio of maximum possible pressure reduction (MPR) to the initial overbalance pressure for the gas zone (difference between initial hydrostatic pressure and fluid zone pressure, OBP), provides a means to evaluate the annular fluid flow potential. A FPF is defined as:

$$FPF = \frac{MPR}{OBP} \qquad (3.3)$$

The FPF can vary between zero and infinity, and the severity of the potential fluid migration problem is rated, based on unpublished rules, as given in the table below:

Table 3.2 Classification of FPF.

FPF	Severity Rating
<4	Minor
4 to 8	Moderate
>8	Severe

ii) Static Gel Strength (SGS):

All SGS determination was performed with MINIMACS, a device designed to analyze a cement composition gel strength behavior under static conditions, and simulate dynamics operations.

iii) Simulated pressure reduction due to static gel strength:

For testing slurry resistance to internal gas flow during setting, equipment, Fluid Migration Analizer (FMA), Chandler, was used to evaluate a particular cement composition to contain fluid.

Field Data Analysis and comparison with FMA test results:

Three wells were studied in Santa Barbara and San Joaquin fields located in eastern Venezuela. Well parameters and properties of cement slurry used in each well are as given in the table below:

Table 3.3 Wells parameters and cement slurry properties:

Well	Liner	Gas Zone	Pore Pressure	Slurry Density	BHST	Compressive Strength at 24 hours	Thickening Time (Hr:min)	Fluid loss (ml)	Filtrate (ml/30 min)
1	$5^{1/2}$ in	7983 to 8756 ft	1517 to 2081 psi	9.2 to 9.3 ppg	254°F	1300 psi	5:00	0	36
2	$5^{1/2}$ in	7670 to 16870 ft	7010 to 8474 psi	11 to 13.5 ppg	288°F	2100 psi	6:51	0	24
3	$13^{3/8}$ in	877 to 2204 ft	413 to 956 psi	12.7 to 15.6 ppg	142°F	1980 psi	8:16	0	41

When applying the methodology to determine the FPF, Transition time, SGS at zero overbalance, OBM, FMA test result, and Field result are given below in the table

Table 3.4 Methodology parameters for each well.

Parameters	**Well 1**	**Well 2**	**Well 3**
FPF	1-2	1-2	9-11
Transition time	32 min.	43 min.	138 min.
SGS (at zero OBM) lbf/100 ft^2.	1222	1301	120
Overbalance, psi	3799	2207	1004

FMA	No gas migration	No gas migration	Gas migration
Field result	No gas migration	No gas migration	No gas migration

This table shows that FPF rating indications is came true with field result as well as FMA result.

3.3.5 Gained Experience:

The proposed methodology can predict the fluid migration occurrence at particular well conditions, hence allowing the selection of the optimum cement slurry design, in order to assure the zonal isolation. The fluid migration control is a complicated issue that can be study with the appropriate instruments and following the appropriate steps, like measurement of FPF, SGS, and drop pressure simulation.

4. Analytical Modeling of Cement Sheath Failure by Internal Pressure and Rising Temperature; developed in this Thesis:

Cement sheath failure by internal well pressure and temperature change is believed to result from sheath stress cracking / shear bond failure caused by diametrical and circumferential casing alteration.

An attempt shall be made to quantify the failure (damage) as a function of down hole conditions and down hole geometry and to define optimum cement mechanical properties to sustain the induced stresses. After a description of the models used to predict the state of stress in a cased cemented well bore, an analysis of the mechanical response of a set cement to variation in down hole pressure and temperature shall be presented. We then show a field example to document the variation of down hole conditions in the field and to demonstrate some types of zonal isolation problems and how to address them.

Just to be clear, this is not a response to the problem of gas migration, but it helps to design cement's sheath properties depending on the site specific and process specific differential internal well pressure and temperature, and field stresses.

4.1 Case study for typical values to be applied in simulation:

Different parameters regarding well bore parameters, cement, casing and formation properties are taken from different sources representing the base case values. Base case casing program is shown in Figure 4.1. They are typical in the sence that parameters taken represents a HPHT well with high field stress.

a) Drilling parameters are taken from Kristin oil field of Norway[6], Well R-3H (all data are referred to bottom):

Casing depth, z:	4500 m
Fracture pressure, p_f:	975 bar (97.5 MPa)
Well pressure, p_w:	934 bar (93.4 MPa)
Pore pressure, p_o:	895 bar (89.5 MPa)
Horizontal field stress, σ_h:	938 bar (93.8 MPa)
Reservoir temperature, T_r:	175^o C (347 ^{o}F)
Well circulation temperature, T_i:	150^o C (302 ^{o}F)
Hole size, $2r_b$:	0.3111 m (12 ¼ inch)

b) Casing and Cement parameters taken from technical reports:

Casing's Young modulus[7], E_s:	200 GPa (2.9x10^7 psi)
Casing's linear expansion coefficient[5], α_s:	12.4 x 10^{-5} in/in. ^{o}F

Cement's Young Modulus[7], E_c: 12.4 GPa (1.8×10^6 psi)

c) Other parameters taken arbitrarily:

Geo-thermal gradient:	2^o C / 100 m
Surface temperature:	10^o C (50 ^{o}F)
Geo-thermal temperature at bottom hole:	100^o C (212 ^{o}F)
Portland cement's compressive strength, C_c:	20.68 MPa (3000 psi)
Cement's tensile strength , C_t:	8.273 MPa (1200 psi)
Shear bond of casing/cement interface, C_s:	6.894 MPa (1000 psi)
Casing type:	P-110
Casing outer diameter, $2r_m$:	0.2444m (9 5/8 inch)
Casing wall thickness, t_s:	0.0138m (0.545 inch)
Casing inner diameter, $2r_a$:	0.2167m (8.535 inch)
Cement wall thickness, t_c:	0.03333m (1.3125 inch.)

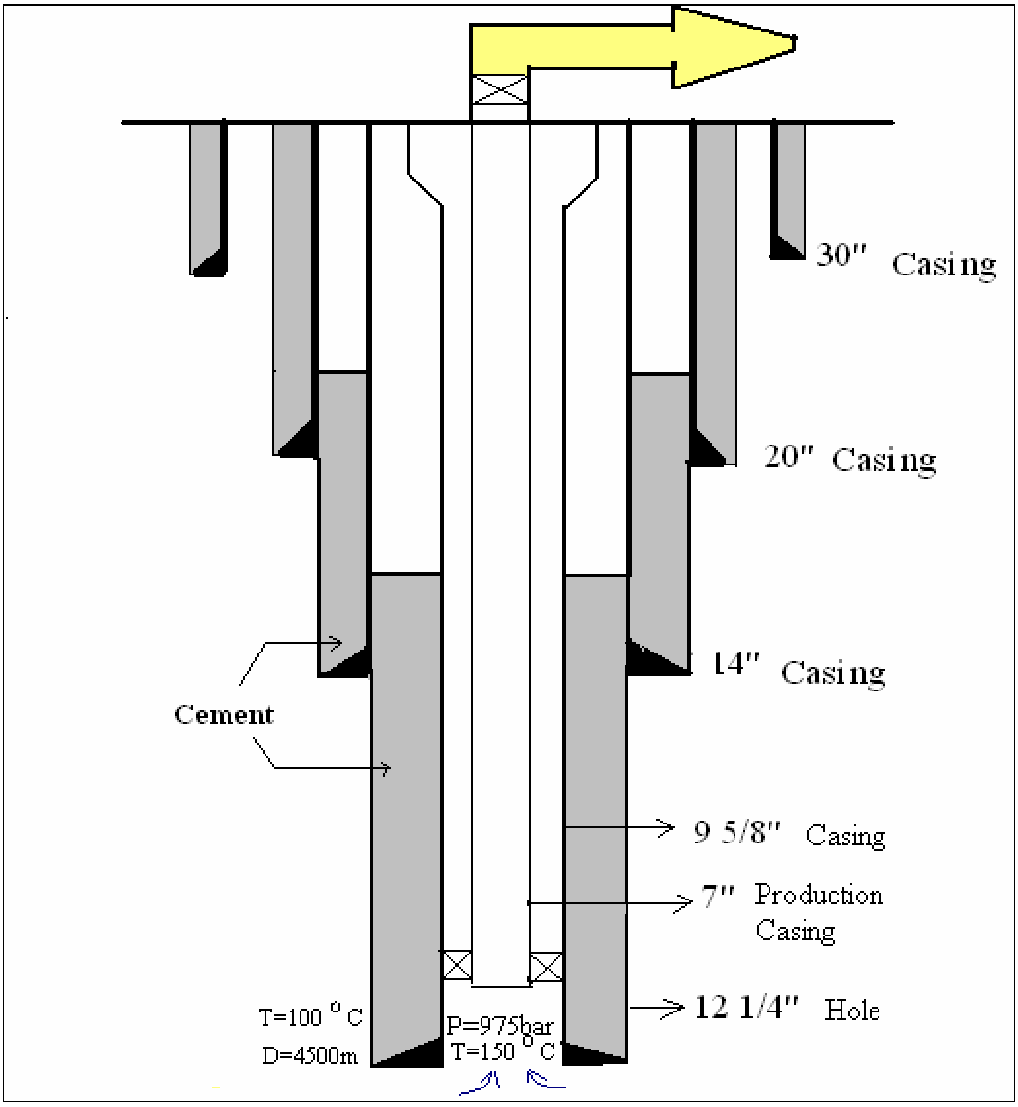

Figure 4.1: Casing program representing the Base case.

4.2 Modeling of Stresses:

The stresses in the cement are calculated assuming that steel, cement, and rock are thermo-elastic materials. It is also assumed that the steel/cement interface and the cement/rock interface are both fully bounded. In the analysis presented here, it is also assumed that the cement is under no internal stress after setting. Only the variations of pressure, stress, or temperature that occur once the cement has set are considered. The geometry of the problem is axisymmetric, with the axis of symmetry being the well bore axis allowing the use of cylindrical coordinates r, θ, and z. The simplest situation is when the boundary and initial conditions (well bore pressure, far-field state of stress, well bore, and far-field temperature) are independent of θ. The variables of interest are then the radial displacement, radial stress, σ_r; hoop stress, σ_θ, hoop strain, and the temperature, T.

Thermo-elasticity provides a linear relationship between the strains, ε_r, ε_θ, ε_z, and temperature, T, as follows in polar co-ordinate[4]:

$$\varepsilon_r - \alpha T = \frac{\sigma_r}{E} - \frac{\mu}{E}(\sigma_\theta + \sigma_z) \tag{4.1}$$

$$\varepsilon_\theta - \alpha T = \frac{\sigma_\theta}{E} - \frac{\mu}{E}(\sigma_z + \sigma_r) \tag{4.2}$$

$$\varepsilon_z - \alpha T = \frac{\sigma_z}{E} - \frac{\mu}{E}(\sigma_r + \sigma_\theta) \tag{4.3}$$

To make the analytical process simpler, the following situations have been assumed.

Assumptions:

1. Plane strain is assumed, no axial movement.
2. Radial displacements and radial stresses are continuous across the interface.
3. Horizontal field stresses are isotropic.
4. Steel, cement, and rock are thermo-elastic materials.
5. Stress in each ring is fully determined as a function of the elastic properties, boundary conditions, and cased well bore geometry.
6. Thin wall pipe situation is selected for all annuli.
7. Cement is free of initial stresses.
8. Borehole wall is fixed and exerting field stress σ_h.
9. Casing temperature is equal to reservoir fluid temperature while cement sheath is in normal geothermal temperature.

4.2.1 Derivation of Equations:

a) Stresses due to internal pressure:

The stresses in the casing/cement ring are determined by the linear elastic solution in polar co-ordinate derivation in the ring section as shown in figure 4.2 below which shows a cut of a cylinder of wall thickness 't', along the longitudinal axis as shown in Figure 4.2 (a), and stress in the plane section, Figure 4.2 (b).

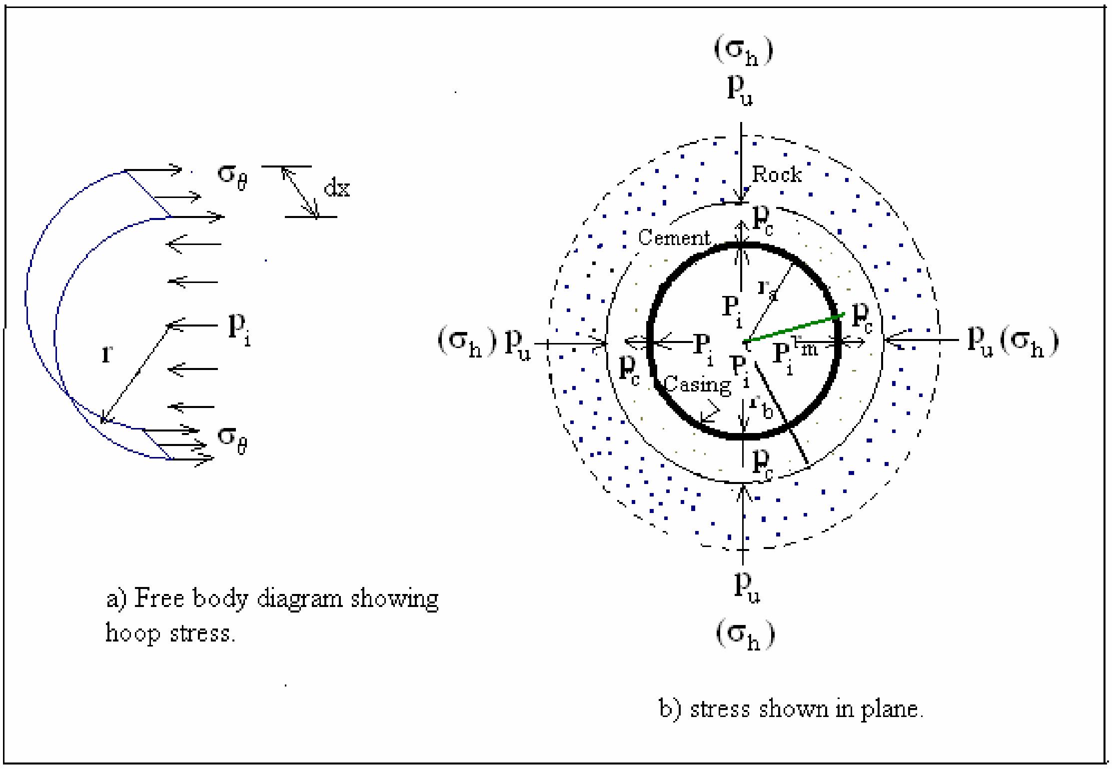

Figure 4.2: Stress in thin wall pipe segment (after reference 2 and 8).

A simple cylindrical vessel of radius r and wall thickness t is subjected to an internal pressure p_i, which induces equal bi-circumferential or hoop stresses σ_θ. This stress can be denoted using cylindrical $r\theta$ z, co-ordinates as σ_θ.

The free body is in static equilibrium. According to Newton's first law of motion, the hoop stress yields,

$$2\sigma_\theta t dx = p_i 2r dx \tag{4.4}$$

$$\sigma_\theta = \frac{p_i r}{t} \quad \text{(tensile)} \tag{4.5}$$

The hoop stress is a principal stress[8] as shown in Figure-4.2(a). The sign convention is that tensile stresses are positive and compressive stresses are negative.

- The above formula is good for thin walled cylinder. Generally, thin wall means radius, r, is larger than 5 times its wall thickness, t (r > 5t).

- When a cylinder is subjected to external pressure, the above formula is still valid. However, the stresses are negative since the wall is now in compression instead of tension.

$$\sigma_\theta = \frac{-p_u r}{t} \quad \text{(compression)} \tag{4.6}$$

As the casing in the borehole has open ends there will be no axial stress since there are no ends caps for the drilling fluid to push against. Only hoop stress $\sigma_\theta = \frac{p_i r}{t}$ exists, and the corresponding hoop strain is given by Hooke's Law as:

$$\varepsilon_\theta = \frac{\sigma_\theta}{E} = \frac{p_i r}{tE} \tag{4.7}$$

Since this strain is the relative change in circumference (δ_c divided by the original circumference 2πr) we can write:

$$\delta_c = C\varepsilon_\theta = 2\pi r \frac{p_i r}{tE} \tag{4.8}$$

The change in circumference and the corresponding change in radius $\delta_r = \delta_c / 2\pi$. The radial expansion becomes;

$$\delta_r = \frac{p_i r^2}{tE} \tag{4.9}$$

This equation can be used in case of compound cylinders. In case of a cemented casing, the casing, the cement and the formation constitute inner, middle and outer cylinder. The compound cylinders case has been shown in figure 4.2(b). A contact pressure, p_c, develops at the interface between casing and cement. While p_i (well pressure) and p_u (formation stress, σ_h) act on inner surface of casing and outer surface of cement respectively. The inner cylinder (casing) expands according to the difference p_w-p_c, while outer cylinder (cement) expands according to p_c-p_u. From displacement boundary values it can be postulated that until the consecutive cylinders remains in contact, the radial expansions of inner and outer cylinder must be the same. We can write the radial expansions in this case as follow:

$$\delta_s = \delta_c$$

$$\frac{(p_i - p_c) r_a^2}{t_s E_s} = \frac{(p_c - p_u) r_m^2}{t_c E_c} \tag{4.10}$$

In terms of well pressure (p_w) and field stress (σ_h), the equation becomes:

$$\frac{(p_w - p_c)r_a^{\ 2}}{t_s E_s} = \frac{(p_c - \sigma_h)r_m^{\ 2}}{t_c E_c} \qquad (4.11)$$

and contact pressure, p_c, as:

$$p_c = \frac{p_w + \sigma_h \left\{ \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}} \right\}}{1 + \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}}} \qquad (4.12)$$

From the boundary condition, the contact pressure, p_c, is the radial stress, σ_r, in the inner surface of the cement which causes the compression in the cement sheath. So the radial stress and hoop stresses can be expressed as:

$$\sigma_r = \frac{p_w + \sigma_h \left\{ \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}} \right\}}{1 + \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}}} \qquad (4.13)$$

$$\sigma_\theta = \frac{(p_w - p_c)r_a}{t_s} \qquad (4.14)$$

From equation 4.12, we will have,

$$\sigma_\theta = \frac{\left[p_w - \frac{p_w + \sigma_h \left\{ \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}} \right\}}{1 + \frac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}}} \right] r_a}{t_s} \qquad (4.15)$$

b) Stresses due to temperature:

Stresses caused by thermal expansion can be derived as internal pressure. Usually the bottom hole injection temperature of the treating fluid differs from the initial reservoir temperature. With this differential temperature, the thermal stresses are induced in the cemented casing and rock formation. For a temperature change, ΔT (final temperature – initial temperature), the linear strain, ε, in the element is given by[12]:

$$\varepsilon = \alpha \Delta T \qquad (4.16)$$

Where α is the linear coefficient thermal expansion. The stress is given by:

$$\sigma = \varepsilon E \tag{4.17}$$

Where, σ, is thermal stress and, E, is young modulus of the element concerned.

In cemented casing as shown in figure 4.2(b), the difference in radial expansion due to ΔT, as per assumption-9, will be:

$$\Delta r_s = \Delta T \alpha_s r_m \tag{4.18}$$

But this is the length of radial expansion opposed to expand, so, this radial expansion will cause thermal radial stress in the casing/cement interface as given by:

$$\sigma_r = \Delta T \alpha_s r_m E_s \tag{4.19}$$

In the same way the differential circumferential length opposed to expand also causes thermal hoop stress in casing and casing/cement interface as given by:

$$\sigma_\theta = \Delta c_s E_s = 2\pi \Delta T \alpha_s r_m E_s \tag{4.20}$$

c) Total stresses:

To count for both internal pressure and thermal effect on stresses at a time, stresses from both causes are added to get the total stresses. Summation of radial stresses from pressure and thermal effect gives total radial stress as given below;

$$\sigma_r = \frac{p_w + \sigma_h \left\{ \dfrac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}} \right\}}{1 + \dfrac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}}} + \Delta T \alpha_s r_m E_s \tag{4.21}$$

Likewise, summation of hoop stresses gives total hoop stress of the casing at the casing/cement contact as shown below;

$$\sigma_\theta = \frac{\left[p_w - \dfrac{p_w + \sigma_h \left\{ \dfrac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}} \right\}}{1 + \dfrac{t_s E_s r_m^{\ 2}}{t_c E_c r_a^{\ 2}}} + \Delta T \alpha_s r_m E_s \right] r_a}{t_s} \tag{4.22}$$

Likewise, the total hoop stress of cement sheath at the cement/formation contact will be:

$$\sigma_{\theta f} = \frac{\left[\frac{p_w + \sigma_h \left\{ \frac{t_s E_s r_m^{\,2}}{t_c E_c r_a^{\,2}} \right\}}{1 + \frac{t_s E_s r_m^{\,2}}{t_c E_c r_a^{\,2}}} + \Delta T \alpha_s r_m E_s - \sigma_h \right] r_m}{t_c} \qquad (4.23)$$

Equations 4.21, 4.22, and 4.23 are the formulae used to calculate radial and hoop stresses as a function of well pressure and temperature. Total stress is then compared with tensile strength and shear bond strength to predict failure of cement sheath.

5. Analysis of Stresses and Evaluation of Cement Failure:

The stresses generated due to pressure and/or temperature change will normally concentrate at the boundaries between materials with contrasting deformational parameters. Outside the cemented casing the boundaries are at the casing/cement interface or at the cement/formation interface. For linear elastic, isotropic materials the predominant induced stresses will be radial and tangential. Radial stress acts perpendicular to the axis of the well bore outward towards the formation while tangential stress acts perpendicular from the direction of radial stress. Tangential stress in this analysis can be referred to as the hoop stress. Radial stress is usually compressive in nature while hoop stress is generally tensile. In certain circumtances, however, radial stress can be tensile in character and hoop stress can be compressive. Generally, in a casing/cement/formation configuration with an increase in well pressure, the highest radial and tangential stress will be found at the casing/cement interface.

The mechanical parameter's characterisation of the cement sheath obviously impacts the ability of cement sheath to withstand the expected changes in temperature, pressure and far field stress. Of the most important is the Young Modulus of elasticity. Elastic cement with lower value of Young Modulus provide greater flexibility to the shaeth failure.

In a casing/cement/formation environment, radial cracking of the cement sheath can happen. Radial cracking is normally due to tangential and flexural forces rather than compressional forces. These forces start at the annulus boundaries, when the casing expand or contract. They can also occur due to compressional forces in extreme cases, such as in an annular gap between a soft and a hard casing or a soft casing and a hard formation[13]. At the boundary, under high loads (variations in hydrostatic pressure or well temperature), compressional forces could destroy the cement sheath by stress crushing. An analysis of stress development due to well pressure, temperature, and field stress has been carried out in the following paragraphes. Depending on the value and nature of the stresses, an evaluation of cement sheath failure has been performed. As the field stresses, well pressure, and differential temperature are the function of depth and we have considered the 4500m well depth, the cement failure analysis is for the given depth specific.

Data given in chapter 4.1 were used to find the value for radial stress (σ_r), hoop stress in casing at casing/cement contact (σ_θ), and hoop stress in cement at cement/formation contact ($\sigma_{\theta f}$) using equations 4.21, 4.22, and 4.23. According to these equations we have three input values; namely well pressure (p_w), far field stress (σ_h), and temperature difference between casing and cement (ΔT). Seven combinations of input values, i.e. seven cases, have been outlined to see the effect of different physical parameters such as internal pressure, well temperature, in-situ field stress, in the development of different stresses.

Table 5.1 Input and Output values for case 1 to 7.

	Input Values			Output Values				
Case No.	p_w (Pa)	σ_h (Pa)	ΔT (^oC)	Ratio[1] (A)	Stress by ΔT	σ_r (Pa)	σ_θ (Pa)	$\sigma_{\theta f}$ (Pa)
1	9.34E+07	9.38E+07	5.00E+01	8.52E+00	1.52E+07	1.09E+08	1.16E+08	5.54E+07
2	9.34E+07	0	5.00E+01	8.52E+00	1.52E+07	2.50E+07	7.73E+08	9.16E+07
3	9.34E+07	0	0	8.52E+00	0.00E+00	9.81E+06	6.55E+08	3.60E+07
4	9.34E+07	9.38E+07	0	8.52E+00	0.00E+00	9.38E+07	-2.80E+06	-1.54E+05
5	0	9.38E+07	0	8.52E+00	0.00E+00	8.39E+07	-6.57E+08	-3.61E+07
6	0	9.38E+07	5.00E+01	8.52E+00	1.52E+07	9.91E+07	-5.39E+08	1.94E+07
7	0	0	5.00E+01	8.52E+00	1.52E+07	1.52E+07	1.19E+08	5.56E+07

The casewise values of radial stresses are compared with the compressive strength of cement as shown in Figure 5.1.1 and the value of hoop stresses are compared with the tensile strength of cement as shown in Figure 5.2.2.

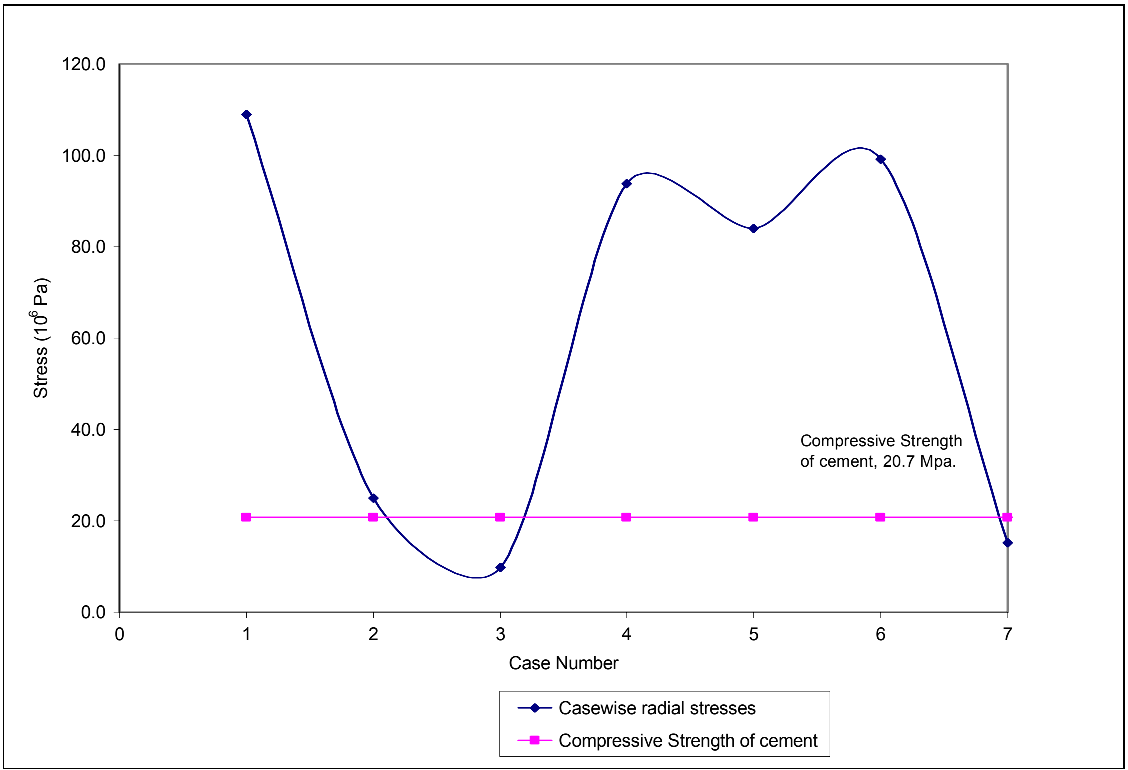

Figure 5.1.1 : Casewise radial stresses compared with Cement Compressive Strength.

[1] $A = t_s E_s r_m^{\ 2} / t_c E_c r_a^{\ 2}$

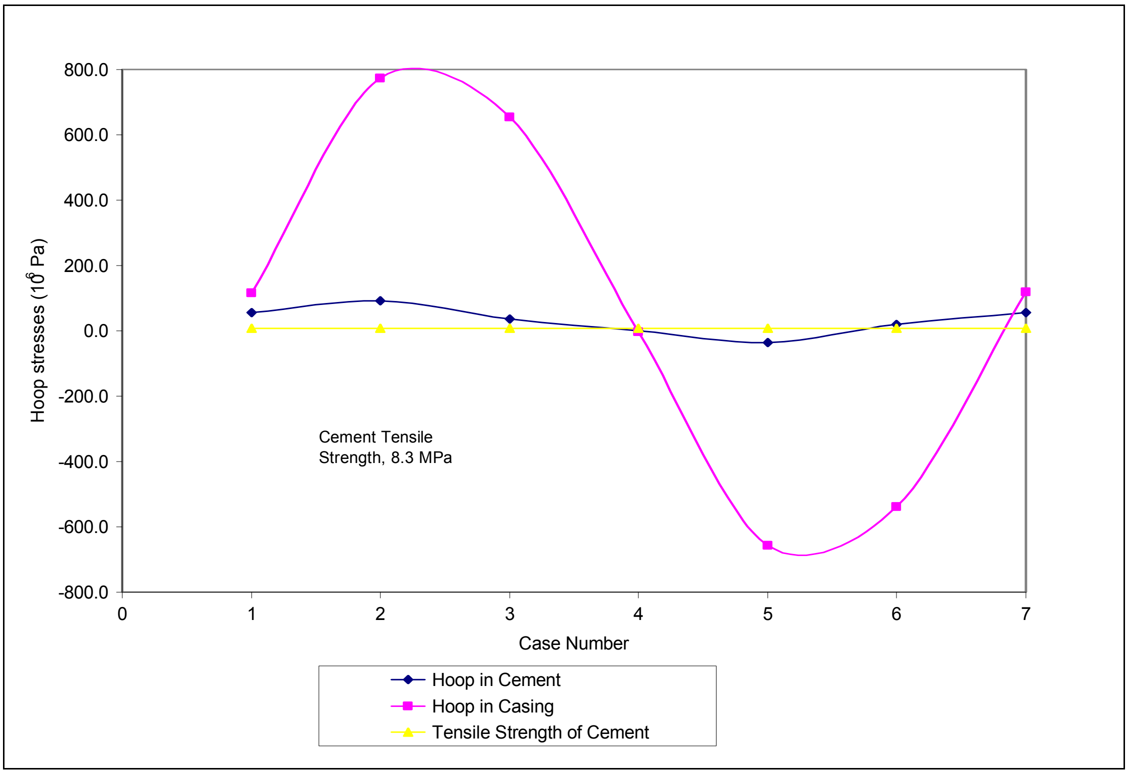

Figure 5.1.2 : Casewise hoop stresses compared with Cement Tensile Strength.

The first case (Case No.-1) is the base case with well pressure, far field stress and temperature stress all acting in the annulus. The radial stress become 109 MPa (15809 psi), which is far more than base case compressive strength (3000 psi). So the cement in this case might be stress crushed. To withstand the stress the cement should have a higher strength than 16,825 psi. The hoop stress of cement is 55.4 MPa (8035 psi) and it is tensional. The cement hoop stress is greater than the shear bond strength of 6.89 MPa (1000 psi) and tensile strength, 8.27 MPa (1200 psi). So this situation also indicates bond failure and tensile failure. Base case cement shall not withstand the base case stresses.

Case No.-2 assumes no effect from the far field stress in the cement sheath. In this case radial stress is 25 MPa (3625 psi), slightly higher than cement compressive strength. Hoop stress in cement is 91.6 MPa (13285 psi) and is tensile, much higher than cement tensile strength. For the base case cement, both stress crushing and tensile failure are possible.

Case No.-3 assumes the situation where field stress and thermal stress have no effect on cement sheath (no difference in temperature between casing and cement). Radial stress is 9.81 MPa (1423 psi), less than compressive strength of the base case cement. The cement hoop stress is 36 MPa (5221 psi) more than tensile strength. Cement will not undergo stress crushing but will have tensile failure.

Case No.-4 assumes the situation where thermal stress has no effect on cement sheath (no difference in temperature between casing and cement). Radial stress is 93.8

MPa (13605 psi), more than compressive strength of the base case cement. The cement hoop stress is 154 KPa (22 psi) and casing hoop stress is 2.8 MPa (406 psi). Both hoop stresses are compressive in nature and cement shear bond strength 6.89 MPa (1000 psi). In this case cement will undergo stress crushing only.

Case No.-5 assumes the situation where internal pressure is zero and thermal stress has no effect on cement sheath (no difference in temperature between casing and cement). Radial stress is 84 MPa (13605 psi), more than compressive strength of the base case cement. Hoop stress in cement and casing 36.1 MPa (5235 psi) and 657 MPa (95289 psi), both are compressive. Cement will undergo shear bond failure due to compressive hoop stress in the casing before stress crushing and tensile failure.

Case No.-6 assumes the situation where well pressure is zero. Only the thermal stress and the field stress has effect on cement sheath. Radial stress is 99.1 MPa (14373 psi), more than compressive strength of the base case cement. Hoop stress in cement is 19.4 MPa (2813 psi), tensile, which is more than tensile strength of the cement. So radial crushing, bond failure and tensile failure, all are possible.

Case No.-7 assumes the situation where only thermal stress has effect on cement sheath (no well pressure and no far field stress). Radial stress is 15.2 MPa (2204 psi), less than compressive strength of the base case cement. Cement hoop stress is 55.6 MPa (8064 psi), tensile, more than tensile strength. Cement will undergo tensile failure though stress crushing is prevented.

Out of the above seven cases, three cases namely Case-3, Case-5, and Case-7 show the separate effect of each individual parameter, well pressure, field stress, and thermal stress respectively. It can be seen that well pressure and thermal effect creates stresses of tensile nature while field stress creates stresses of compressive nature in the cement. Base case well pressure value causes radial stress less than compressive strength but hoop stress in cement more than tensile strength of cement. So well pressure causes tensile failure of the cement not the crushing stress. Base case far field stress causes radial stress more than compressive strength of cement, and hoop stress in the casing more than base case bond strenth at casing/cement contact. So, far field stress alone causes stress crushing, bond failure of the cement. The base case temperature difference (thermal stress) causes radial stress less than compressive strength of cement, cement hoop stress (tensile) more than tensile strength of the cement. So thermal stress is responsible for tensile failure at cement/formation contact.

Analysis of seven cases show that even individual base case parameter (the differential pressure across the casing, the thermal stress, and the far field stress) can causes cement failure of one form or other. The HPHT well conditions in combination with high far field stress is destructive for an ordinary type of cement sheath as assumed in the base case. So the base case cement specifications is not capable of sealing the annulus of the drill hole under the assumptions made.

The Kristin oil-field, well R-3H, is a HPHT field. Due to high reservoir pressure and temperature they selected a thick wall high grade casing program. The production casing is 9 7/8", 64.4 lb/ft, Q-125 in the bottom part of the string and 9 7/8", 64.4 lb/ft, SM-125 in the upper part of the string. High grade (σ_{yield} < 125x103 psi) means high burst and high collapse pressure rating.

5.1 Short coming in the Stress Analysis:

During this stress analysis, the input values of well pressure and temperature are assumed to increase from zero initial values. This is normally not the case. While cementing the annulus, completion fluid is used for the placement of cement. This fluid has been exerting hydrostatic pressure to the casing before the setting of the cement. This means casing already has an initial internal pressure stress of some value. The well pressure during production only causes the stress equivalent to the pressure value more than the completion well pressure value. That means only the value of pressure difference between production and completion is responsible for additional stress on the cement. So we need to use pressure difference value instead of production pressure value in the column of well pressure in the table 5.1. When this condition apply in the analysis, the stress due to well pressure becomes much lower than the above cases.

Likewise in the case of thermal stress also, difference between the bottom hole well circulation temperature (T_i) and geo-thermal temperature at the bottom hole has been taken as base case temperature difference value between casing and cement. But in the reality, the casing has already undergone thermal stress before well circulation during cementing. Furthermore thermal conduction makes the temperature difference between casing and cement much lower than given temperature value at base case. So thermal stress also would be much less. This means that the combined effect of ciculation well pressure and temperature, and far field stress on the cement sheath would be less severe than as indicated in output value in the table 5.1. The stress on the cement at various pressure, temperature and field stress conditions can be graphically shown (in next chapter) using equations 4.21, 4.22, and 4.23.

5.2 Result of simulation and analysis of stresses dependent of well presssure, temperature and field stress value:

The stress situation on cemented casing depends on well pressure, well circulation temperature and field stress values, and has been shown graphically in the following scenarios. Different cases have been exemplified by casewise scenarios regarding stress development {radial stress on cement **(σ_r)**, hoop stresses on casing **(σ_θ)**, and hoop stress on cement**($\sigma_{\theta f}$)**} depending on the combination of well pressure, temperature, and field stress. Failure of cement sheath, safe pressure and temperature values, have been outlined from each graphical presentation comparing the developed stresses with the compressive strength of cement, tensile strength of cement and shear bonding at contacts.

The most probable siuation is such that far field stress remain constant and only temperature and pressure may be varied depending on the situations. On this basis case-1 (well pressure and temperature, and far field stress are acting, and all can be varied), case-4 (well pressure and field stress are acting and only pressure can be varied), and case-6 (well temperature and field stress are acting and only temperature can be varied) appear most realistic. Only those three cases will be presented and analyzed here.

CASE-1: (Base case values of well pressure, temperature, field stress): In this case five scenario are presented. In scenario 1-4, one parameter is varied (in decreasing order) while keeping other two parameters constant as the base case value. Scenario 5 shows stresses when all three parameters are decreasing upto zero value.

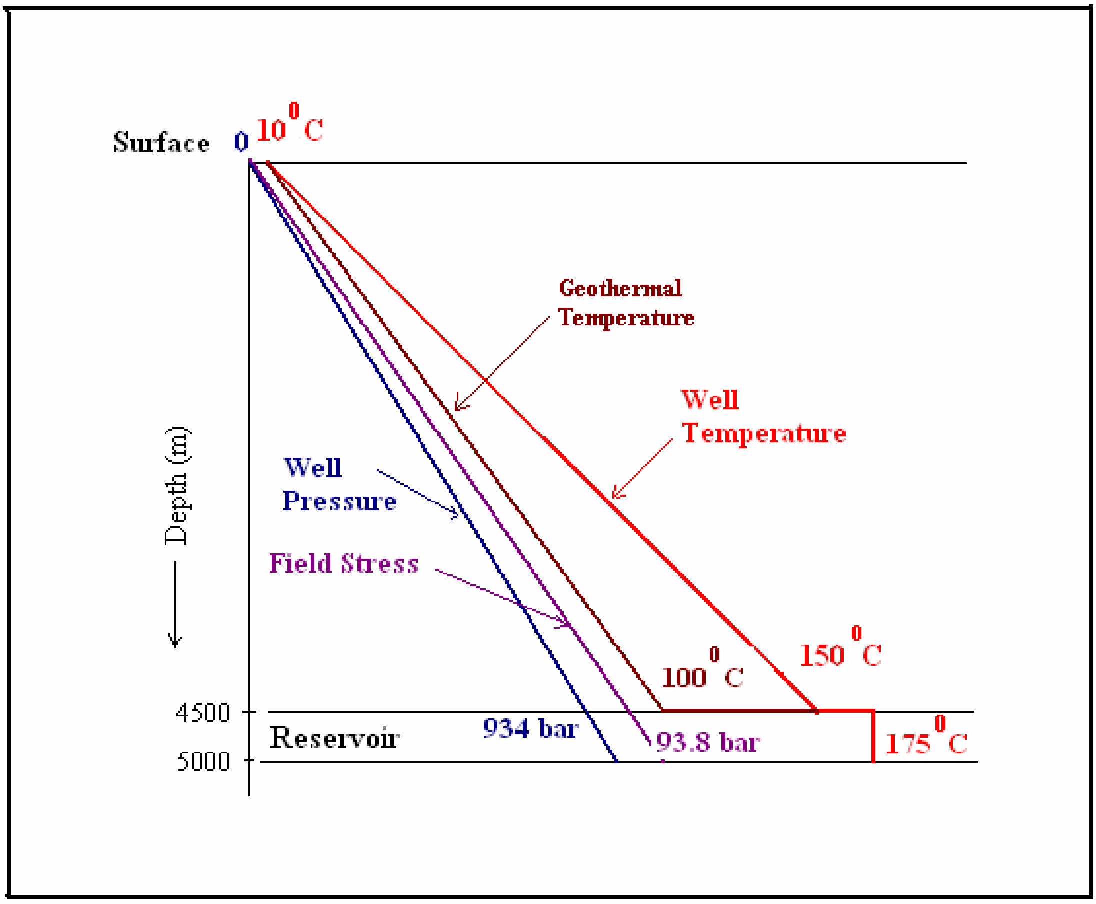

Figure 5.2.1 : Base case well pressure, temperature and field stress.

Scenario-1:

Changes in radial and hoop stresses with decreasing well pressure is analyzed. Well temperature and field stress are kept constant as initial base case value. Well pressure was reduced as shown in the Table 5.2.1 and result are shown in Figure 5.2.2 below:

Table 5.2.1: Change in stresses with well pressure at base case value of ΔT and σ_h.

Input Values	Output Values

p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (°C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	8.5	15.2	108.9	115.9	55.4
84.1	93.8	50	8.5	15.2	107.9	50.4	51.8
74.7	93.8	50	8.5	15.2	107.0	-15.0	48.2
65.4	93.8	50	8.5	15.2	106.0	-80.5	44.6
56.0	93.8	50	8.5	15.2	105.0	-145.9	41.0
46.7	93.8	50	8.5	15.2	104.0	-211.4	37.4
37.4	93.8	50	8.5	15.2	103.0	-276.8	33.8
28.0	93.8	50	8.5	15.2	102.0	-342.3	30.2
18.7	93.8	50	8.5	15.2	101.1	-407.7	26.6
9.3	93.8	50	8.5	15.2	100.1	-473.2	23.0
0.0	93.8	50	8.5	15.2	99.1	-538.7	19.4

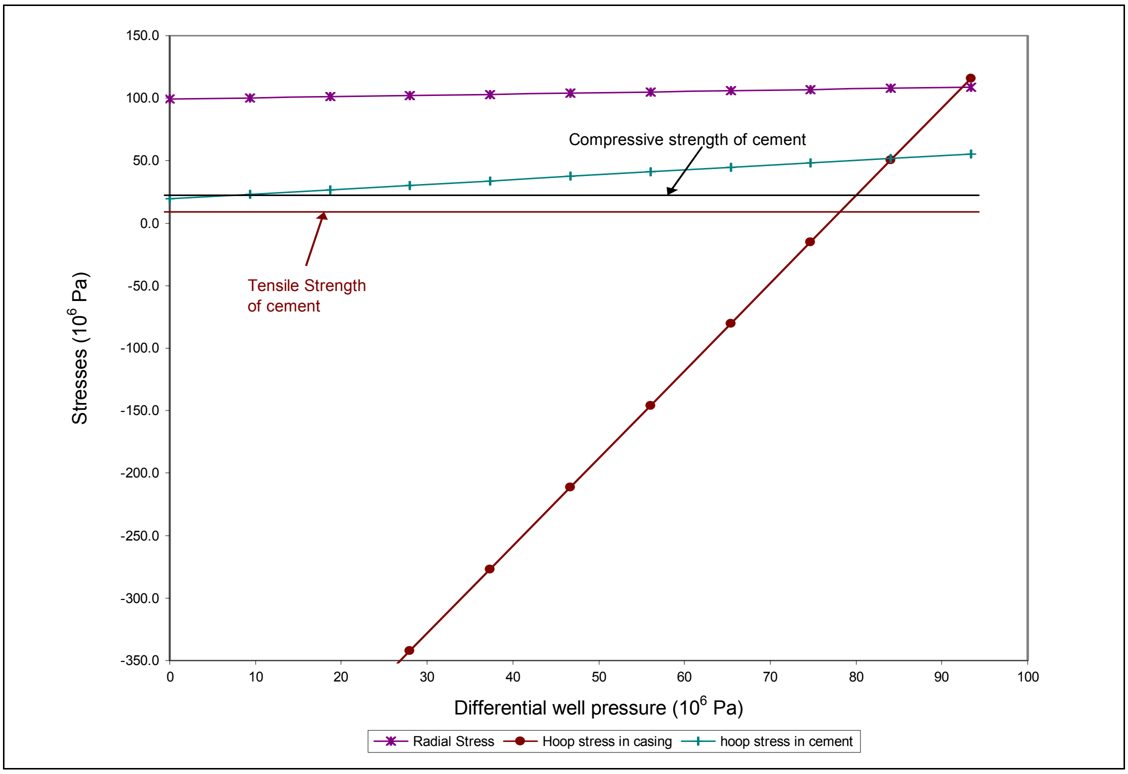

Figure 5.2.2 : Stresses vs well pressure at base case value of ΔT and σ_h.

Result: The radial stress in the cement remains above 99×10^6 Pa and hoop stress in cement is 19.4×10^6 Pa even at well pressure reduced to zero value (surface condition). This indicates that these stress values are due to well temperature and field stress. The radial stresses are higher than compressive strength of cement (20.7×10^6 Pa) and hoop stresses are higher than tensile strength of cement (8.273×10^6 Pa). So it can be said that cement failure occures even at zero well pressure.

In the above graph well pressure really means the pressure difference between inside and outside of the casing in the well. Whenever the pressure inside the casing is higher than the pressure outside, the casing undergoes expansion. That means the hoop stress in the casing is positive. But when pressure outside the casing is higher than inside pressure, the casing undergoes contraction and hoop stress becomes negative. In the figure 5.2.1, the maximum negative hoop stress in the casing at zero well pressure is due to the fact that outside pressure caused by far field stress (σ_h) is much higher. The notion of the well pressure is also applicable in the subsequent scenarios.

Scenario-2:

Changes in radial and hoop stresses with decreasing well temperature have been analyzed. Well pressure was kept constant as initial pressure. Well temperature was reduced as shown in the Table 5.2.2 and result has been shown in the Figure 5.2.3. below:

Table 5.2.2: Change in stresses with well temperature at base case value of P_w and σ_h.

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (^{o}C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	8.5	15.2	108.9	115.9	55.4
93.4	93.8	45.0	8.5	13.6	107.4	104.0	49.9
93.4	93.8	40.0	8.5	12.1	105.9	92.1	44.3
93.4	93.8	35.0	8.5	10.6	104.4	80.3	38.8
93.4	93.8	30.0	8.5	9.1	102.9	68.4	33.2
93.4	93.8	25.0	8.5	7.6	101.3	56.5	27.6
93.4	93.8	20.0	8.5	6.1	99.8	44.7	22.1
93.4	93.8	15.0	8.5	4.5	98.3	32.8	16.5
93.4	93.8	10.0	8.5	3.0	96.8	20.9	11.0
93.4	93.8	5.0	8.5	1.5	95.3	9.1	5.4
93.4	93.8	0.0	8.5	0.0	93.8	-2.8	-0.2

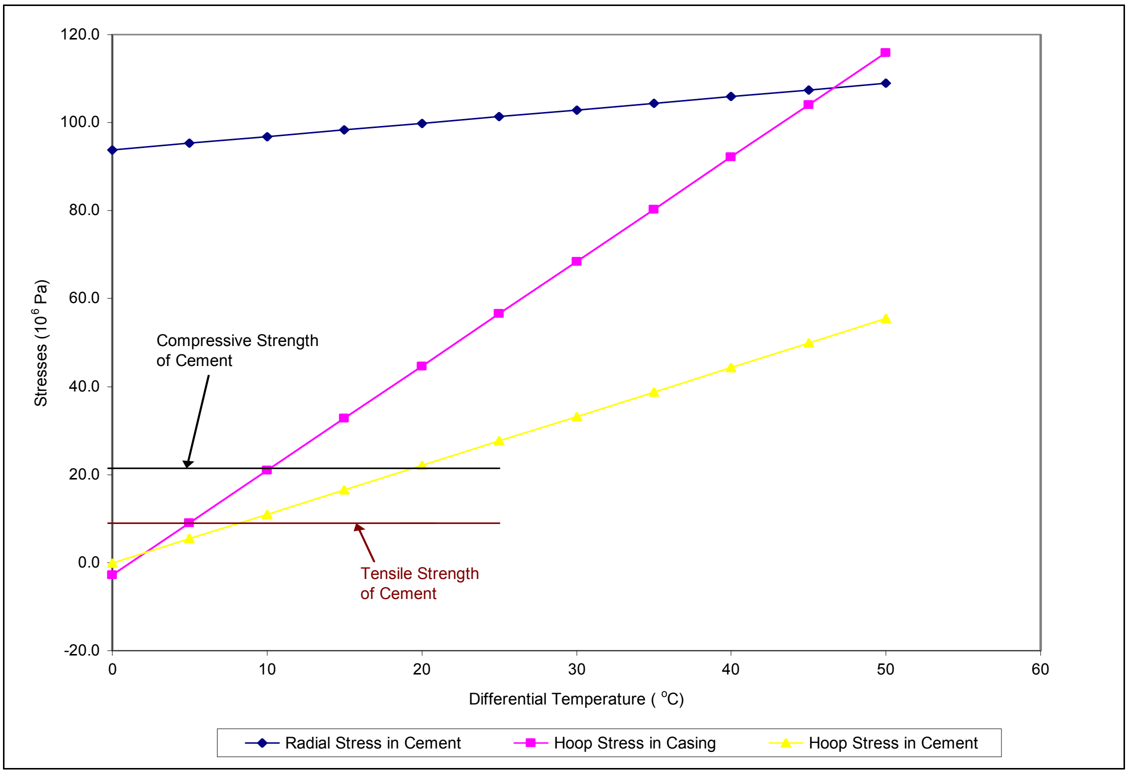

Figure 5.2.3 :Stresses vs well temperature at base case value of P_w and σ_h.

<u>Result:</u> The radial stress remains above 93.8x10^6Pa even at zero temperature. The casing hoop stress is tensile and changing into compressive when temperature decreases. Hoop stress in cement is tensile initially and decreasing in value and changing towards compressive at well temperature approaching to zero value. The radial stress in this example is always more than the compressive strength of cement (20.7x10^6Pa). The cement hoop stress is more than tensile strength of cement (8.273 x10^6 Pa) and becomes less than tensile strength when temperature reduces less than 8°C. So it can be said that cement stress crushing failure occurs even at zero well pressure.

<u>Scenario-3:</u>

Changes in radial and hoop stresses with decreasing well pressure and temperature have been analyzed. Field stress was kept constant as initial base case value. Well pressure and temperature are reduced as shown in the Table 5.2.3 and result are shown in the Figure 5.2.4. below:

Table 5.2.3: Change in stresses with well pressure and temperature at base case value of σ_h.

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (°C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	8.5	15.2	108.9	115.9	55.4
84.1	93.8	45.0	8.5	13.6	106.4	38.6	46.3
74.7	93.8	40.0	8.5	12.1	103.9	-38.8	37.1

65.4	93.8	35.0	8.5	10.6	101.4	-116.1	28.0
56.0	93.8	30.0	8.5	9.1	98.9	-193.4	18.8
46.7	93.8	25.0	8.5	7.6	96.4	-270.7	9.6
37.4	93.8	20.0	8.5	6.1	93.9	-348.1	0.5
28.0	93.8	15.0	8.5	4.5	91.4	-425.4	-8.7
18.7	93.8	10.0	8.5	3.0	88.9	-502.7	-17.8
9.3	93.8	5.0	8.5	1.5	86.4	-580.0	-27.0
0.0	93.8	0.0	8.5	0.0	83.9	-657.3	-36.1

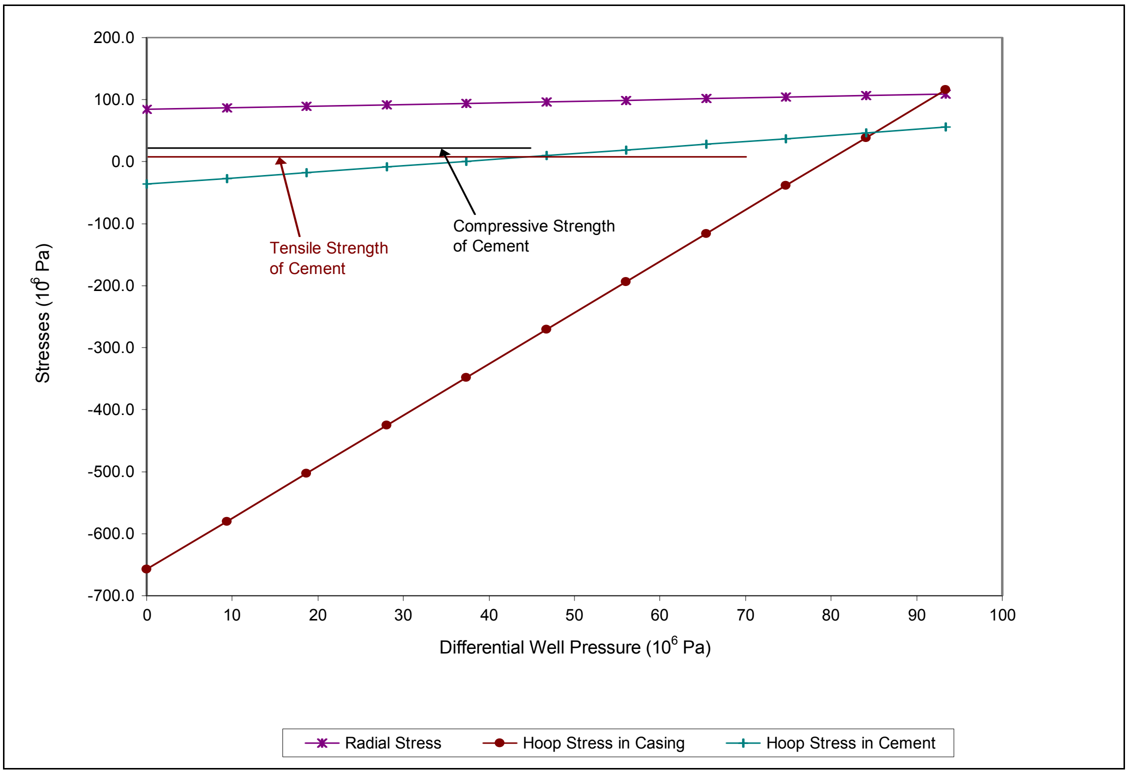

Figure 5.2.4 : Stresses vs well pressure and temperature at base case value of σ_h.

Result: The radial stress remains above $84x10^6$ Pa. The hoop stress in casing is tensile at higher values of well pressure and temperature but changes to compression with decreasing values of well pressure and temperature. The hoop stress in cement is also tensile initially and decreasing in value altimately changing to compressive nature. Radial stress is more than compressive strength of cement ($20.7x10^6$ Pa) and hoop stress is more than tensile strength of cement ($8.27x10^6$ Pa). So it can be said that stress crushing failure of cement occures even at zero well pressure and temperature. No safe value of well pressure and temperature appears in the list.

Scenario-4:

Changes in radial and hoop stresses with decreasing far field stress, σ_h, have been analyzed. Well pressure and temperature are kept constant at base case values. Field stress is reduced as shown in the Table 5.2.4 and result has been shown in the Figure 5.2.5. below:

Table 5.2.4: Change in Stresses with decreasing field stress at constant well pressure and temperature:

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (°C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	8.5	15.2	108.9	115.9	55.4
93.4	84.4	50	8.5	15.2	100.5	181.6	59.0
93.4	75.0	50	8.5	15.2	92.1	247.4	62.7
93.4	65.7	50	8.5	15.2	83.7	313.1	66.3
93.4	56.3	50	8.5	15.2	75.3	378.8	69.9
93.4	46.9	50	8.5	15.2	66.9	444.6	73.5
93.4	37.5	50	8.5	15.2	58.5	510.3	77.1
93.4	28.1	50	8.5	15.2	50.2	576.0	80.7
93.4	18.8	50	8.5	15.2	41.8	641.8	84.3
93.4	9.4	50	8.5	15.2	33.4	707.5	88.0
93.4	0.0	50	8.5	15.2	25.0	773.2	91.6

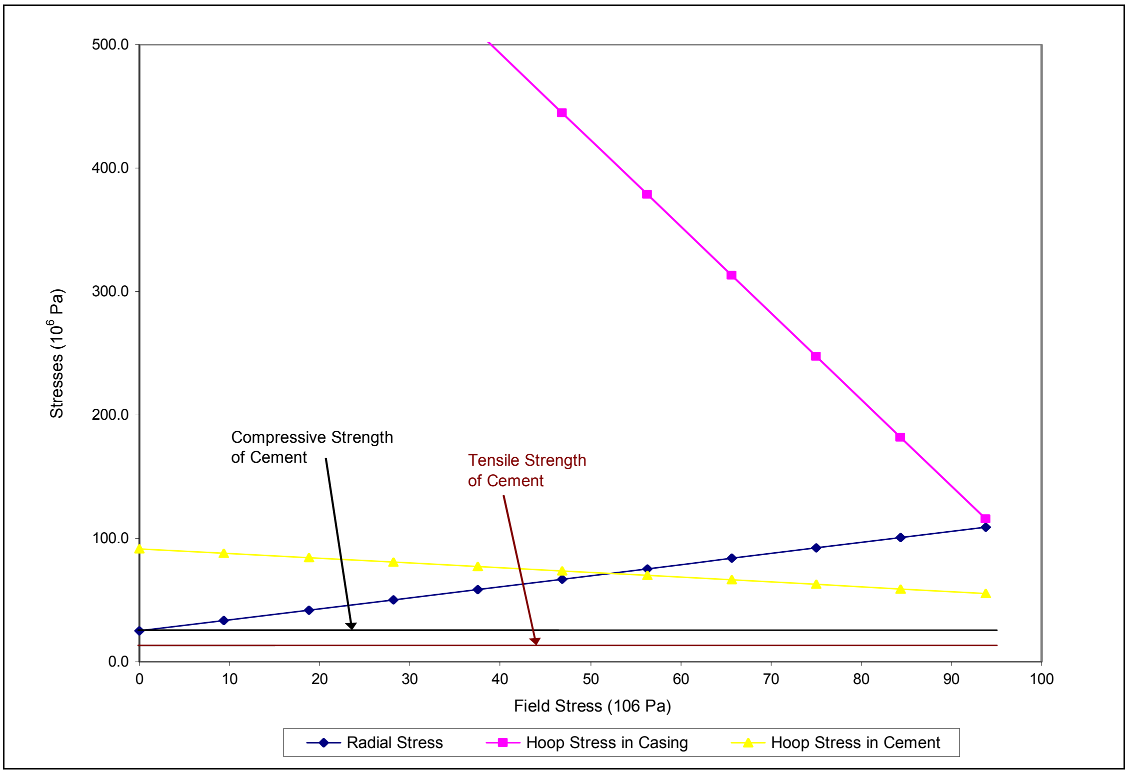

Figure 5.2.5: Change in Stresses with decreasing field stress at constant well pressure and temperature:

<u>Result:</u> The radial stress is always more than compressive strength of the cement (20.7×10^6 Pa) even at zero field stress. The hoop stresses in casing and cement are increasing as field stress decreases. This is due to the fact that well pressure and temperature have same nature of additive stresses. This means stress crushing of cement

is obvious. Hoop stresses are also always above the value of tensile and shear bond strengths of cement, so, tensile failure is also unavoidable in the given pressure and temperature conditions. A point to be noted is that hoop stresses in casing and cement without far field stress is much more than hoop stresses with field stress. This indicates that field stress helps to curtain the hoop stresses but increases the radial stress.

Scenario-5:

Changes in radial and hoop stresses with decreasing all parameters as far field stress (σ_h), well pressure and temperature have been analyzed. Values are reduced as shown in the Table 5.2.5 and result has been shown in the Figure 5.2.6 below:

Table 5.2.5: Change in Stresses with decreasing field stress, well pressure and temperature:

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (°C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	8.5	15.2	108.9	115.9	55.4
84.06	84.4	45.0	8.5	13.6	98.0	104.3	49.9
74.72	75.0	40.0	8.5	12.1	87.1	92.7	44.3
65.38	65.7	35.0	8.5	10.6	76.2	81.1	38.8
56.04	56.3	30.0	8.5	9.1	65.3	69.5	33.3
46.7	46.9	25.0	8.5	7.6	54.5	57.9	27.7
37.36	37.5	20.0	8.5	6.1	43.6	46.4	22.2
28.02	28.1	15.0	8.5	4.5	32.7	34.8	16.6
18.68	18.8	10.0	8.5	3.0	21.8	23.2	11.1
9.34	9.4	5.0	8.5	1.5	10.9	11.6	5.5
0	0.0	0.0	8.5	0.0	0.0	0.0	0.0
14.01	14.07	7.5	8.5	2.3	16.3	17.4	8.3

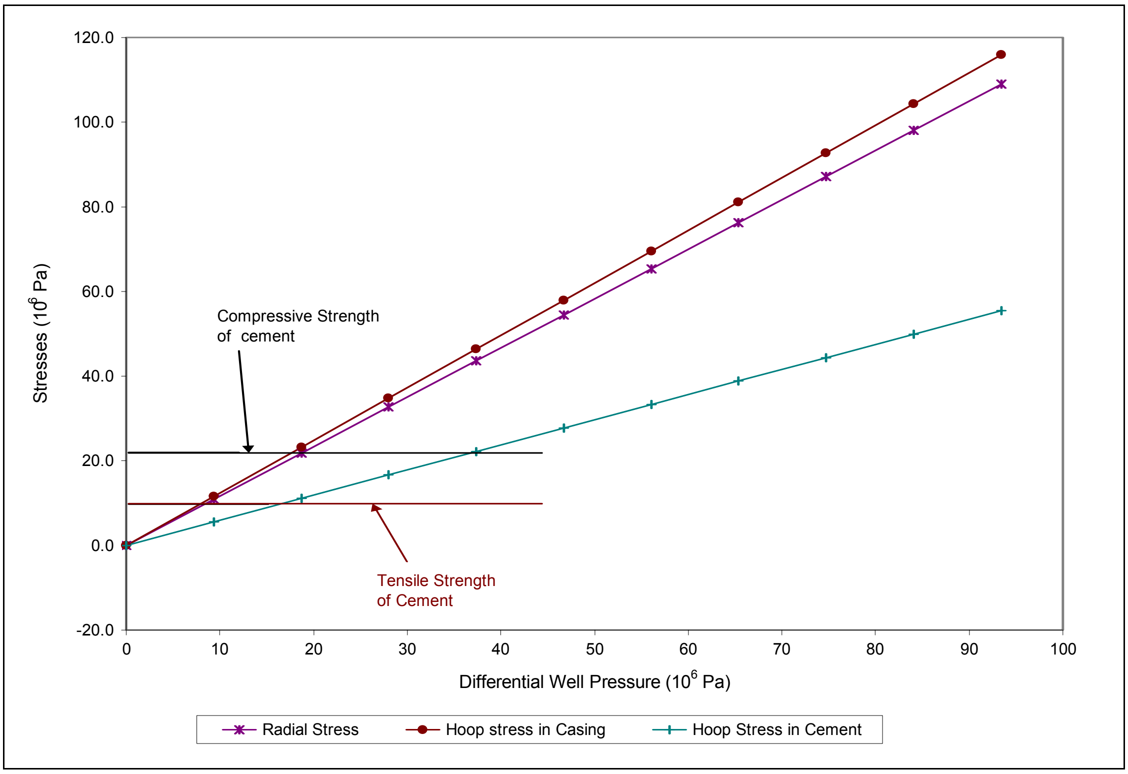

Table 5.2.6: Change in Stresses with decreasing field stress , well pressure and temperature:

<u>Result:</u> The radial stress (σ_r), hoop stress in casing at casing/cement contact (σ_θ), and hoop stress in cement at cement/formation contact ($\sigma_{\theta f}$) appears decreaing in value as well pressure, temperature, and field stress decrease. Hoop stress in casing and in cement are tensile. The values of well pressure, temperature and field stress which gives radial stress less than compressive strength, and cement hoop stress less than tensile stength of cement are found to be in the last row of the table. The corresponding values are well pressure = 14.01×10^6 Pa, field stress = 14.01×10^6 Pa, and differential temperature = 7.5 ^{o}C.

CASE-4: <u>Well pressure and field stress have base case value, and well ΔT is zero.</u>

<u>Scenario-6:</u>

Changes in radial and hoop stresses with decreasing well pressure have been analyzed. The far field stress is considered constant as base case value but differential temperature is considered zero. Well pressure is reduced as shown in the Table 5.2.6 and result has been shown in the Figure 5.2.7. below:

Table 5.2.6: Change in Stresses with decreasing well pressure at constant field stress and zero temperature:

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (^{o}C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	0	8.5	0.0	93.8	-2.8	-0.2

84.06	93.8	0	8.5	0.0	92.8	-68.3	-3.8
74.72	93.8	0	8.5	0.0	91.8	-133.7	-7.4
65.38	93.8	0	8.5	0.0	90.8	-199.2	-11.0
56.04	93.8	0	8.5	0.0	89.8	-264.6	-14.5
46.7	93.8	0	8.5	0.0	88.9	-330.1	-18.1
37.36	93.8	0	8.5	0.0	87.9	-395.5	-21.7
28.02	93.8	0	8.5	0.0	86.9	-461.0	-25.3
18.68	93.8	0	8.5	0.0	85.9	-526.4	-28.9
9.34	93.8	0	8.5	0.0	84.9	-591.9	-32.5
0	93.8	0	8.5	0.0	83.9	-657.3	-36.1

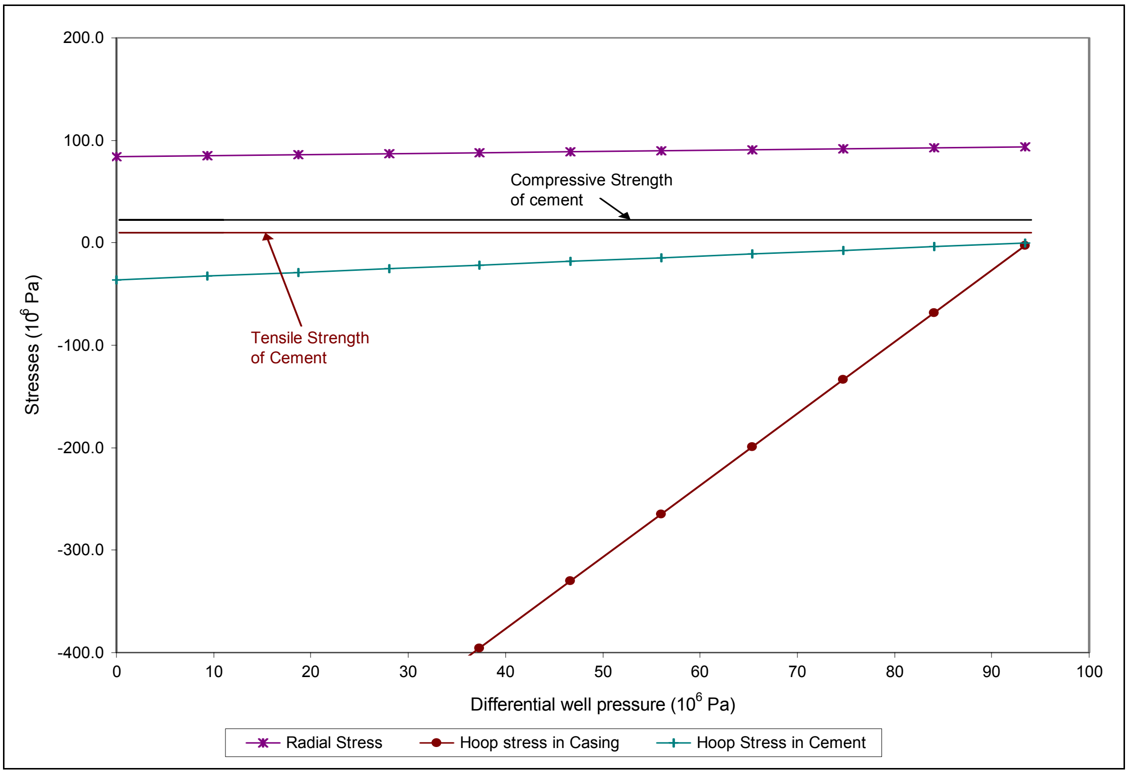

Figure 5.2.7: Change in Stresses with decreasing well pressure at constant field stress and zero temperature:

Result: The radial stress is always more than compressive strength of the cement (20.7 x10^6 Pa) even at zero field stress. This means stress crushing of cement is obvious. Hoop stresses are compressive and gradually increasing as the well pressure decreases. Initial hoop stress is less than shear bond strengths of cement but exeeds the value at first reduction. So bond failure is also unavoidable.

CASE-6: Well temperature and field stress have base case value, and well pressure is zero.

Scenario-7:

Changes in radial and hoop stresses with decreasing well temperature have been analyzed. Far field stress is considered constant as base case value but well pressure is considered zero. Differential temperature is reduced as shown in the Table 5.2.7 and result are shown in the Figure 5.2.8. below:

Table 5.2.7: Change in Stresses with decreasing temperature at constant field stress and zero well pressure:

Input Values			Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (°C)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
0	93.8	50	8.5	15.2	99.1	-538.7	19.4
0	93.8	45.0	8.5	13.6	97.6	-550.5	13.9
0	93.8	40.0	8.5	12.1	96.1	-562.4	8.3
0	93.8	35.0	8.5	10.6	94.6	-574.3	2.8
0	93.8	30.0	8.5	9.1	93.0	-586.1	-2.8
0	93.8	25.0	8.5	7.6	91.5	-598.0	-8.4
0	93.8	20.0	8.5	6.1	90.0	-609.9	-13.9
0	93.8	15.0	8.5	4.5	88.5	-621.7	-19.5
0	93.8	10.0	8.5	3.0	87.0	-633.6	-25.0
0	93.8	5.0	8.5	1.5	85.5	-645.5	-30.6
0	93.8	0.0	8.5	0.0	83.9	-657.3	-36.1

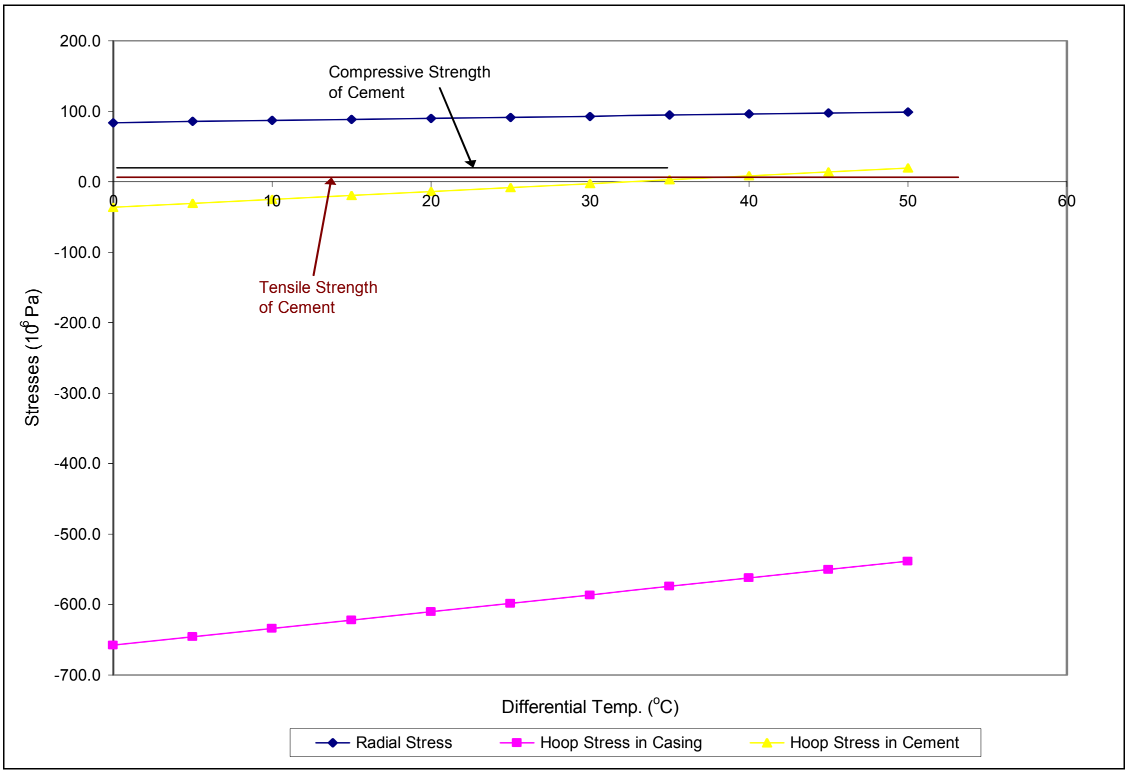

Figure 5.2.8: Change in Stresses with decreasing temperature at constant field stress and zero well pressure:

Result: The radial stress is always more than compressive strength of the cement (20.7 x10^6 Pa) even at zero thermal stress (=83.9x10^6 Pa). This means stress crushing of cement is obvious. The cement hoop stress is tensile at higher temperature but changes to compressive as temperature reduces. As temperature approaches to zero, stresses are caused by field stress only. It can be postulate that base case value of far field stress alone is sufficient for stress crushing of the cement. In this scenario safe value of temperature does not appear.

5.3 Stress States dependent on Mechanical Parameters of cement:

The key mechanical parameters of the cement responsible for whether or not sheath failure will occur are Young's Modulus, Poisson's Ratio and tensile strength. In the derivation of the cement's radial stress (σ_r), hoop stress in casing at casing/cement contact (σ_θ), and hoop stress in cement at cement/formation contact ($\sigma_{\theta f}$) in this thesis work, only the Young Modulus of cement (E_c) has been in scene. So the effect of young modulus value on the different stresses has been checked. Changes in stresses with E_c value has been shown in Table 5.3.1 and Figure 5.3.1 below for the base case values of well pressure, temperature, and field stress:

Table 5.3.1: Change in radial and hoop Stresses with cement's Young Modulus:

Input Values				Output Values				
p_w (10^6Pa)	σ_h (10^6Pa)	ΔT (^oC)	Ec (10^6 Pa)	Ratio[1] (A)	Stress by ΔT (10^6Pa)	σ_r (10^6Pa)	σ_θ (10^6Pa)	$\sigma_{\theta f}$ (10^6Pa)
93.4	93.8	50	1000	105.6	15.2	109.0	115.6	55.6
93.4	93.8	50	2000	52.8	15.2	108.9	115.6	55.6
93.4	93.8	50	4000	26.4	15.2	108.9	115.7	55.5
93.4	93.8	50	8000	13.2	15.2	108.9	115.8	55.5
93.4	93.8	50	12000	8.8	15.2	108.9	115.9	55.4
93.4	93.8	50	16000	6.6	15.2	108.9	116.0	55.4
93.4	93.8	50	24000	4.4	15.2	108.9	116.1	55.3
93.4	93.8	50	32000	3.3	15.2	108.9	116.3	55.2
93.4	93.8	50	48000	2.2	15.2	108.8	116.5	55.1
93.4	93.8	50	64000	1.7	15.2	108.8	116.7	55.0
93.4	93.8	50	96000	1.1	15.2	108.8	117.0	54.9
93.4	93.8	50	128000	0.8	15.2	108.7	117.3	54.8

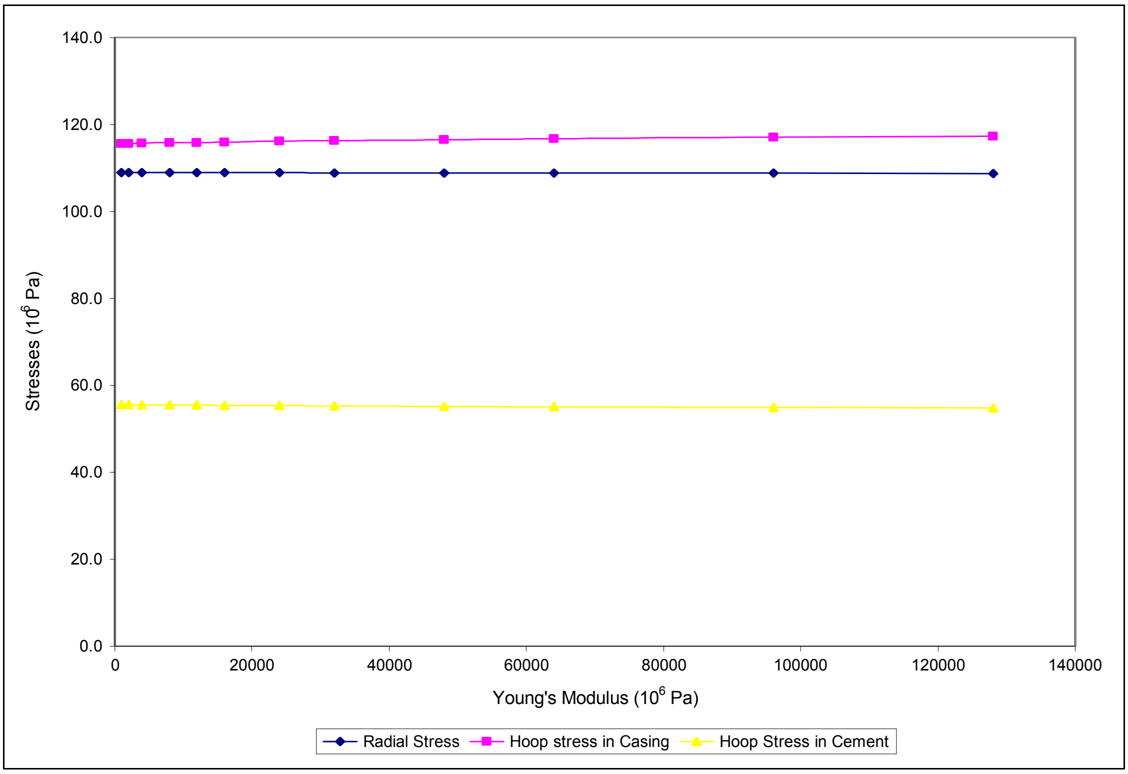

Figure 5.3.1: Change in Stresses with changing cement's Young Modulus:

Result: Graph shows that stresses change slightly with cement's Young Modulus. It seems in the case of high pressure and high temperature (HTHP) conditions of the well that stresses much depend on the value of well pressure, temperature difference and field stress rather than mechanical properties of the cement.

6. Discussion:

Cement integrity over life of well conditions has a high priority within the well cementing. Increasing awareness of problems associated with cement sheath failure and subsequent loss of zonal isolation has demanded that set cement material behavior and coupled behavior of casing, cement and formation be more fully understood. Solid mechanical properties (stress and strain relationship, compress ional, tensional and flexural strengths) of set cement, casing and formation are the prime behavior controlling parameters under the various pressures and temperature regimes existed during the life of a well. Additional parameters such as the density, specific heat, thermal conductivity, and coefficient of thermal expansion are also equally important.

In this thesis work we have presented an analysis of the mechanical response of the set cement and casing in terms of amount and type of stresses created due to changes in pressure and temperature regime in a wellbore. Values of resulting stresses are compared with strengths (compressional, tensional, shear bond) to predict the type of failure, either cement debonding or cement radial cracking or stress crushing.

While making the analysis, thin wall pipe situation, plane strain, and abrupt temperature variation between casing and cement sheath were assumed among others. These assumptions have guided the formulation of expressions where only some parameters (Young's modulus, thickness, radius, coefficient of thermal expansion) of casing and set cement are in the scenario. Consideration of abrupt temperature variation has caused over-estimation of possible stresses. Furthermore, thin wall situation has restricted the analysis of stresses/strain along the radial distance of the set cement (from casing/cement interface to cement/formation interface).

Modeling with consideration of thick wall pipe, thermal conductivity, and solid strain leads to much more realistic analysis of mechanical response of set cement to stresses due to changing temperature and pressure situations and location of response. The statical and classical approach for the analysis involving all parameters seems much complex and lengthy (beyond the scope of this thesis work). Though the approach adopted in this thesis work is more statical and classical, and the stresses value determined is in higher side, the prediction of cement failure comparing cement mechanical properties to developed stresses is helpful in designing the cement slurry depending on the individual well conditions.

Now a days various "cement strength simulator" and "program for Finite Element Method (FEM)" are in use to predict cement's mechanical strengths (compressive, tensile and flexural) and mechanical response to induced stresses in the well. Such models are based on certain assumptions like linear thermo elasticity, various isotropic conditions, thick wall pipe, and strain based deformation [4,14,15]. They have found that rock properties of the cement and casing such as Young's modulus and Poisson's ratio play extreme roles in the integrity of the cemented casing system.

In the analytical modeling developed in this thesis work, improvements for better cement failure prediction can be made by inclusion of solid strain, thick wall pipe condition, and thermal conductivity.

7. Conclusion:

On the basis of the study and analysis the following conclusions have been drawn:

1. Gas migration phenomena can be caused by various factors and can take place at different time period. Short term leakage are associated with cementing operation i.e. slurry characteristics, displacement mechanics, hydrostatic pressure, where as long term leakage are related to mechanical and thermal stresses (compressional / tensional) which compromise the integrity of hydraulic bond or the integrity of the cement materials.

2. Analysis of stresses due to internal casing pressure and temperature variation helps provide a probabilistic determination of the competency of particular cement mechanical properties.

3. Casing expansion creates radial cracks (tensional) in the set cement in the annulus, which causes loss of annular zonal isolation. Casing contraction causes elastic expansion of cement initially, then it becomes plastic and the hydraulic bond is broken (formation of micro annulus). So high compressive strength is not crucial for cement sheath integrity, rather improving the elasticity or it's flexural and tensile strength is an elegant solution to prevent debonding.

4. Far field stress helps to curtain the hoop stresses in the casing which can be beneficiary from cement integrity point of view.

5. At high pressure and temperature well changes in cement elasticity (Young's Modulus) has little effect on the stress changes.

6. Cement sheath failure are mainly associated with casing expansion / contraction due to internal pressure and/or temperature variation. So casing with high Young's modulus and low thermal expansion shall be beneficial.

8. Nomenclature:

bbl	= barrel.
C_c	= Compressive strength of cement.
C_s	= Shear bond strength of casing/cement interface.
C_t	= Cement tensile strength.
E	= Young's modulus of elasticity.
Gpa	= 10^9 pascal.
HPHT	= high pressure, high temperature.
KPa	= 10^3 pascal.
Lbf	= pound force.
mD	= milli darcy.
MPa	= 10^6 pascal.
p_o	= Pore pressure.
p_f	= Fracture pressure.
p_c	= Pressure on contact layer.
p_w	= Well pressure.
p_i	= Inner pressure.
p_u	= Outer pressure.
r_a	= Casing inner radius.
r_b	= Bore hole radius.
r_c	= Casing outer radius.
T	= Temperature.
ΔT	= Change in temperature (final temperature – initial temperature).
t_c	= Cement wall thickness.
t_s	= Casing wall thickness.
z	= Vertical depth.
γ_c	= Density of cement.
γ_w	= Water density.
δ_c	= Increment in circumference.
δ_r	= Increment in radius.
ε	= Strain.
σ_1	= Maximum principle stress.
σ_3	= Minimum principle stress.
σ_h	= Horizontal field stress.
σ_{hmin}	= Minimum horizontal field stress.
σ_{hmax}	= Maximum horizontal field stress.
σ_r	= Radial stress.
$\sigma_{r'}$	= effective radial stress.
σ_z	= Axial stress.
σ_θ	= Tangential stress / hoop stress at casing/cement contact.
$\sigma_{\theta f}$	= Tangential stress / hoop stress at cement/formation contact.
μ	= Poisson ratio
μ_m	= Micrometer.
α_c	= Linear expansion co-officient, cement.
α_s	= Linear expansion co-officient, casing.

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