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Wellhead Elongation in Cyclic Steam Stimulation Wells in San Tome Operational Area, Orinoco Oil Belt, Venezuela

F. Armas, PDVSA; J. Rodriguez, PDVSA; A. López, Petropiar; R. Mago, PDVSA; J. Cadena, Petropiar; R. Figuera, PDVSA; and P. Arellano, Petropiar

ABSTRACT

The San Tome District, located in the Orinoco Oil Belt - Venezuela, performs cyclic steam injection frequently and it is considered as one of the stimulation method more efficient to extract Heavy Oil crude. This process is defined by injection of a predetermined volume of steam (water) into the reservoir where the main objective consists in reducing the oil viscosity in order to improve the fluid mobility.

A wellbore is the principle link between a hydrocarbon reservoir and surface and is used as a way to transport fluids. One of the key challenges of steam injection is to find the best way that supplied heat reaches down to the reservoir avoiding any adverse impact to the wellbore.

The materials used in the construction of these producing oil wells are often subject to high and low levels of mechanical deformation due to temperature changes by the injection of a hot fluid. At subsurface level, the mechanical structure of the well could be affected by this deformation, as displayed at surface through the axial displacement of the wellhead (elongation).

The main objective of this paper is to analyze wellhead elongation caused by heat loss transmitted to through the casing during cyclic steam stimulation. In this paper, axial deformation of the wellhead sections will be evaluated using elongation statistics from cyclic steam injection wells in Bare Field.

KEY WORDS

Cyclic Steam Stimulation, Insulated Tubing, Vacuum Insulated Tubing, Casing Stress, Material Elongation, Fatigue, Maximum Yield Point, Post Elastic Limit

INTRODUCTION

Recovery of Heavy and Extra Heavy crude oil contained in the Orinoco Heavy Oil Belt in Eastern Venezuela is challenging due to its physical and chemical properties. The high viscosity of the crude oil makes it a candidate for thermal recovery techniques that can reduce the viscosity and dramatically improve the oil mobility.

Steam injection is the most commonly used process to transmit heat to the formation. The disadvantage of this process is that only part of the heat generated reaches the target formation due to heat losses at the surface and to downhole formations. But for many years in the oil industry, steam injection has been the application of choice as a thermal enhanced recovery method.

CYCLIC STEAM STIMULATION (CSS)

There are two techniques for steam injection in heavy crude reservoirs - cyclic steam stimulation and continuous steam injection. The main differences between these two methods lies in the volume of steam injected, exposure time of heat in the reservoir, and the affected reservoir areal extent. In Cyclic Steam Stimulation (CSS), also known as huff-and-puff, the fluid is injected and produced by the same producer well but sometimes requires a downhole completion change.

The Continuous Steam Injection (CSI) technique typically involves separate injection and production wells, but can be done with a single well as in the case of Single-Well Steam

Assisted Gravity Drainage (SW-SAGD), where a single well has a dual completion and is used as an injector and producer simultaneously. For the purpose of this data analysis, it is important to mention that the CSS method was used for data evaluation and well modeling.

The Cyclic Steam Stimulation technique consists of three phases: first, the phase of steam injection; second, the soaking time while the well is shut-in; and last, when the well is placed on production. See Figure 1 for a visual schematic of the three CSS phases.

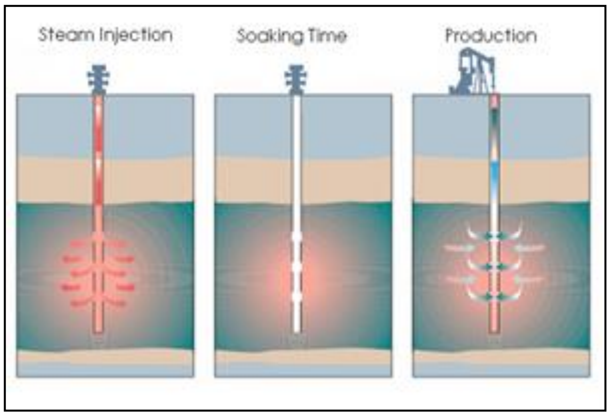

Figure 1: Cyclic Steam Stimulation Phases

The steam injection phase is the period when thermal energy (heat) is being supplied to the reservoir and injection variables such as daily rate, total volume injected, and injection saturation parameters vary depending on reservoir properties. The soaking period starts after shutting-in steam injection and is used to allow energy dissipation into the reservoir. In Bare the soak time is usually approximately 5 days (Armas & Mago 2012). The last stage is when the well is producing fluids from the reservoir to the surface through an artificial lift system suitable for high downhole temperatures. Reservoir injection temperatures using appropriate completion materials in the Orinoco Heavy Oil Belt can reach 500°F or more. This large amount of energy carried out by steam is certainly transmitted to the reservoir by heat transfer and thus achieving insulated tubing function of increasing temperature in the reservoir vicinity.

WELL COMPLETIONS FOR CYCLIC STEAM INJECTION

The wellbore is an important element that provides the physical connection between the reservoir and the surface as wells as the means through which the removal of hydrocarbons is achieved. The efficiency and reliability of this surface-subsurface linkage depends on the selection of components used.

The proper selection and design of well completion assemblies are an important part of the operational and productive performance of a field under thermal recovery. The amount of crude oil recovered from reservoirs under CSS is directly related to the completion of the well. Reducing heat losses will improve the heat delivered to the reservoir which will impact recovery per volume of steam injected.

Two types of well completions are often used for cyclic steam injection in the Orinoco Belt (Armas et al 2012): One is using conventional tubing with nitrogen trapped in the annulus (Figure 2), and the other is using insulated tubing with in-situ fluid in the annulus (Figure 3). Both completions are designed to slow the loss of heat from the injection tubing, which can reduce wellbore mechanical damage and increase heat supplied to the reservoir.

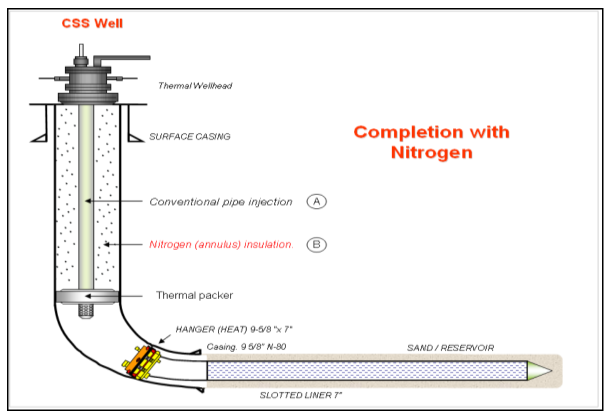

Figure 2: Well Completion with Conventional Tubing and Trapped Nitrogen in the Casing-Tubing Annulus.

As shown in the completion diagram in Figure 2, Point "A" is aiming to the conventional tubing used as the injection string and Point “B" at the nitrogen trapped in the annulus. On the other hand, the second configuration completion shown in Figure 3 uses insulated tubing (IT) shown by Point “A” which consists of double concentric tubing separated internally by a vacuum "annular space". The insulated tubing typically has three elements that contribute to this temperature insulation: a "multi-layered” insulation sheet, a getter or scavenger, and the absolute vacuum system. This completion system provides a significant reduction of heat transfer to its surroundings.

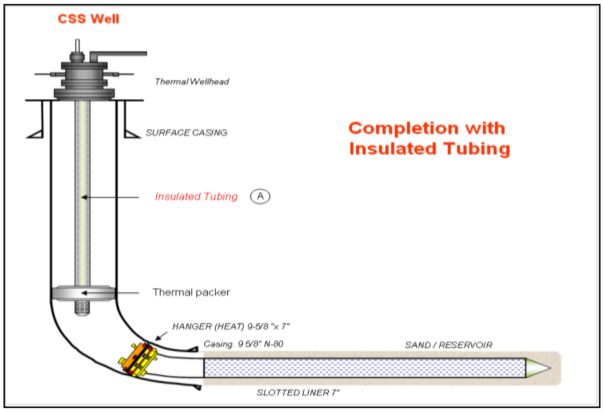

Figure 3: Well Completion using Insulated Tubing

ELONGATION EFFECTS

Elongation is a measure unit of material ductility based on tensile tests. Elongation is represented as a length increase where high deformation means that the material is ductile. A material is said to be ductile when the ratio between longitudinal elongations are accomplished with a reduction in cross-sectional thickness under a tensile load.

Figure 4 below shows a schematic of the response of a cylindrical metal bar to a tensile load. The ductile materials have high deformation behaviors before achieving rupture and thus require higher tensile loads in order to achieve a body failure.

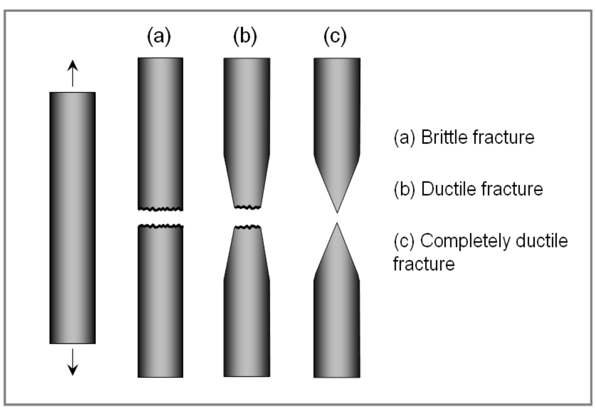

Figure 4: Schematics of Round Metal Bars After Tensile Testing

The metals are characterized by high ductility because the metal atoms are arranged in a way where they slide over one another allowing the meatal to be stretched without breaking.

In an oil producer well, the wellhead is a permanent equipment over the tubing hanger commonly known as Section "C" which is below an adapter flange. On top of the adapter flange the master valves and gauges are located to allow a way to control the well at surface. At the wellhead, the displacement measurements are made from its overall mechanical structure which is an indicator to estimate the well's integrity based on the impact of heat-loss. Figure 5 shows a representative typical wellhead schematic.

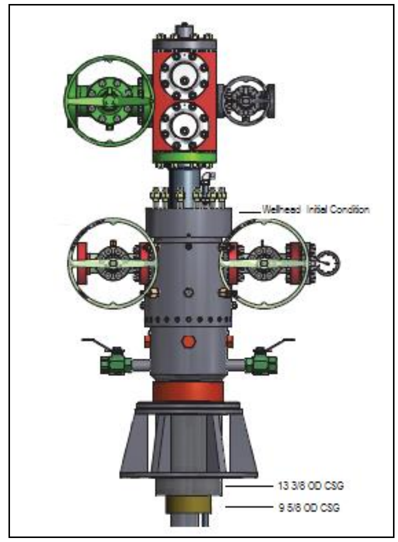

Figure 5: Wellhead Design Diagram

Figure 6 below shows a schematic representation of the wellhead elongation from an original position (initial conditions) until it achieves a new deformed position caused by wellbore thermal stress. The field data in this paper was collected during the process of cyclic steam stimulation which is an indicator that allows to measure elongation and could represent subsurface mechanical well integrity.

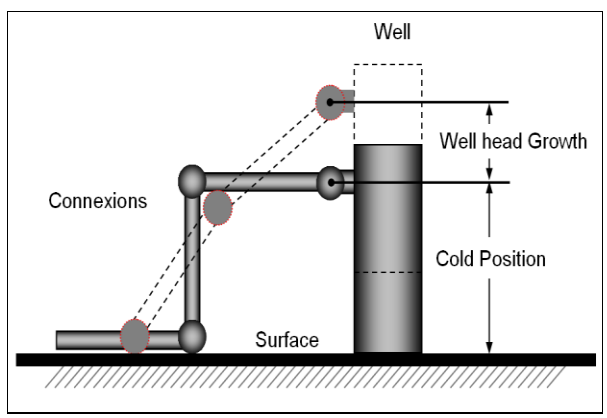

Figure 6: Wellhead Elongation Schematic

The expansion of the materials that are part of the well can be observed from the surface. If elongation or displacement magnitude is high, a deformation of the wellbore materials occurs. Yet, elongation is directly related to the material fatigue due to the materials ductility.

ELONGATION FIELD STATISTICS

For this study, 30 horizontal production wells used for cyclic steam injection were analyzed in the San Tomé District; of which, 25 wells were completed with conventional tubing and nitrogen in the annulus, and the remaining 5 wells were completed with insulated tubing (IT).

Below are the P-50 percentiles of various key operational parameters of 30 wells during the process of CSS:

- Injection Rate: 230 Ton/day (1447 BSPD)
- Total Injection Volume: 4900 Ton (30,821 Bbls)
- Injection Time: 21 days
- Steam Saturation Temperature: 535°F

It was not within the scope of this document to evaluate field operational parameters used in injection phases. The team simply took the field data statistics to develop its respective analysis.

Figure 7 shows the elongation history of 25 wells during the process of cyclic steam stimulation (CSS) completed with conventional tubing and nitrogen trapped in the annulus.

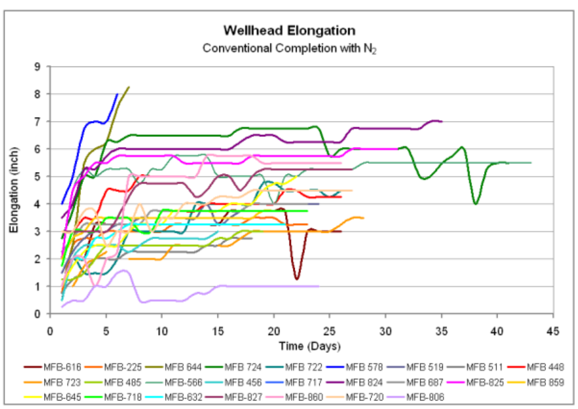

Figure 7: Wellhead Elongation using Conventional Completion

The elongation behavior results from two wells (MFB-578 and MFB-644) stand out in Figure 7 and are shown to be above the statistical average with a total of 8” in 5 days of injection time. At this point, the injection process was shut-in given short period drastic wellhead displacement. The difference in the elongation behavior between one well to the other is mainly due to well characteristics, depth (TVD/MD), equipment metallurgy, hole diameter, quality and top-of-cement, and injection parameters; of which all directly affects the final magnitude of elongation.

On the other hand, Figure 8 shows elongation data for the remaining 5 wells completed with insulated tubing (IT) in same type cyclic steam injections. With this type of insulated tubing completion, smaller magnitudes of elongation are observed versus conventional tubing with nitrogen.

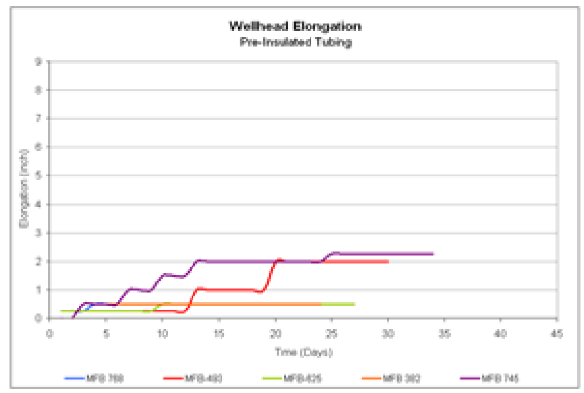

Figure 8: Wellhead Elongation using Insulated Tubing

The completion type used in steam injection plays an important role in material deformation in the well. It is evident that as heat-loss decreases along the well the change in material will be less affected.

To analyze and compare the results shown in Figure 7 and 8, the elongation percentiles were calculated with respect to the injection time for all 30 wells of this study. Figure 9 compares this data between elongation percentile of the best case (P10) for conventional tubing and the worst case (P90) for insulated tubing with respect to injection time.

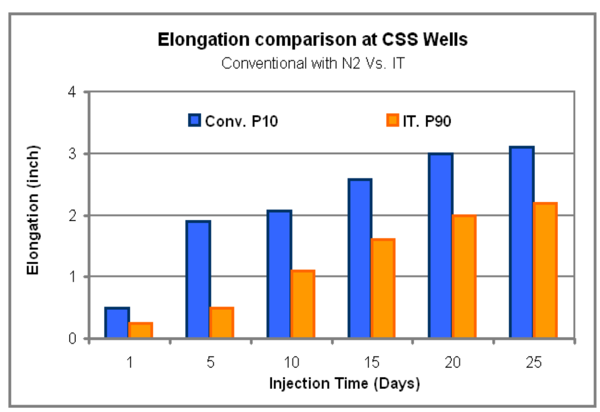

Figure 9: Elongation Percentile for Wells using Conventional Tubing (P10) and Insulated Tubing (P90)

As a result, it is noticed that for each evaluation point (injection time in days), the worst case using insulated tubing (P90) has a magnitude of elongation less than the best case using conventional tubing (P10) which are related to the respective differences in the magnitudes of heat loss in each existing completions of which the insulated tubing better achieves in maintaining mechanical wellbore stability (Armas et al, 2012) (Armas et al, 2015).

As temperature changes within a wellbore are originated, thermal expansion of the material begins. In general terms, during heat transfer, the energy stored in the mechanical structure changes when this energy increases, and so does the length of the material. Thus, solids typically expand when heated and contract when cooled. This behavior of temperature response is expressed by the coefficient of thermal expansion.

Additionally, Figures 14, 15, and 16 in the appendices section of this work are shown with results of the percentiles for P10, P50, and P90 for each of the two CSS completion types.

PARAMETERS EFFECTING WELLHEAD ELONGATION

Variable analysis was performed to determine the elongation behavior considering different scenarios. The first variable analyzed was *injection time* of the total steam injected this being proportional to the amount of heat supplied to the reservoir where the higher the injection time the greater the amount of energy was passed through the wellbore and to the reservoir.

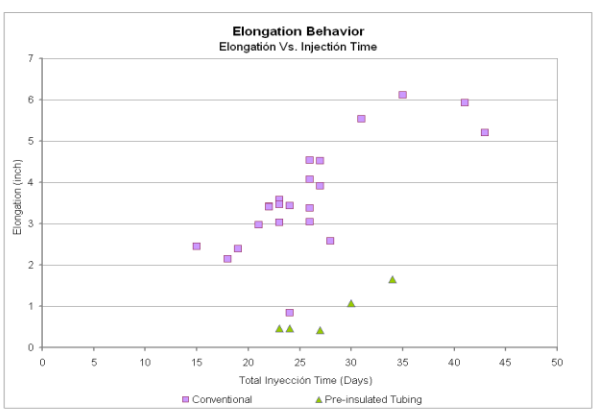

Figure 10: Steam Injection Time vs Wellhead Elongation

Figure 10 shows the real elongation behavior with respect to injection time based on field data obtained from 30 studied wells. The two different completion types used in the San Tome District (Armas *et al* 2012) had a noticeable difference between using conventional tubing and insulated tubing in wellhead elongation by the effect of injection time.

This field behavior is consistent with previous studies (Armas *et al* 2015) demonstrating that heat losses in both completions are totally different having the greatest magnitude of heat transferred with a completion systems consisting of conventional tubing and nitrogen making its respective elongation the highest as noticed in these studied wells. Energy dissipation in a completion with insulated tubing is much lower and thus the effect on the wellbore mechanical structure is reduced thereby decreasing the magnitude of elongation.

Another variable was the *steam saturation temperature* with respect to its effects on elongation. This parameter is related to the amount of energy per unit of time that is being injected and the amount of heat inside the well. The higher the saturation temperature, the higher the temperature difference between the annulus and the steam injected, and as a result the greater the impact of heat flow to the casing and adjacent surrounding along the well (See Figure 11).

In the case of wells completed with conventional tubing the dispersion of elongation data based on steam saturation temperature was high with different range in variations. In any case, Figure 11shows this variable effect on elongation was still well above the behavior observed with respect to the use of insulated tubing.

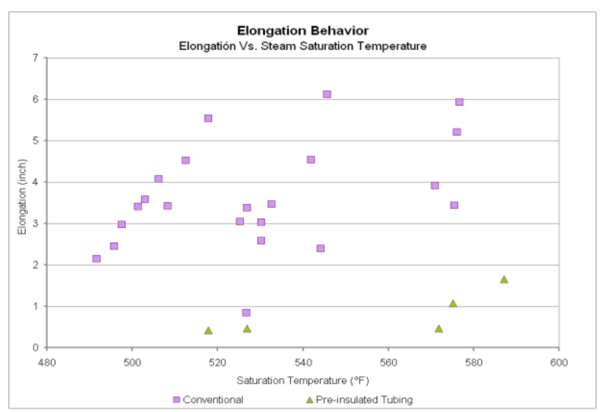

Figure 11: Steam Saturation Temperature vs Wellhead Elongation

The final parameter studied with respect to elongation was *casing pressure* during steam injection. The pressure ranges in the casing have different magnitudes; however, in completion systems with conventional tubing and trapped nitrogen in the annulus, the casing pressure values reached an pressure in the order of 860 psi (P50). On the other hand, in completion systems with insulated tubing, the casing pressure was zero "0" Psi as casing valves were left open during steam injection process as it was not necessary to maintain any isolation fluid (i.e. nitrogen) in the annulus.

As noticed in Figure 12, in the case with conventional tubing with nitrogen in the annulus, an increase in casing pressure from 500-1300 psi adversely affected wellhead elongation increasing at a linear effect between 2-6 inches. Insulated tubing had no annular pressure and had minor impact in elongation.

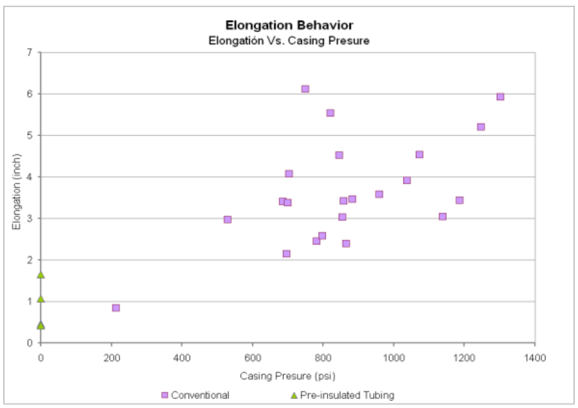

Figure 12: Casing Pressure vs Wellhead Elongation

It is important to note that the presence of gaseous fluid in the annulus has a strong relationship to the observed wellhead elongation with significant casing pressure as the greater the pressure the higher the convection heat transfer coefficient in the fluid as was observed in the case with nitrogen. As a consequence, an increase in heat flow raises thermal energy in the casings and thus increasing deformation.

WELLHEAD ELONGATION WITH RESPECT TO INJECTION CYCLES

The cyclic steam stimulation could be repeated as many times as necessary and shall be considered based on well productivity before and after the steam stimulation, well integrity, surface & downhole equipment availability, workover rig for well intervention, and water source to generate the steam, among other factors. The impact of the cyclic steam jobs with respect to wellhead elongation was analyzed using field data obtained from two wells which had repeated number of cycles with its behaviors shown on Figure 13 below.

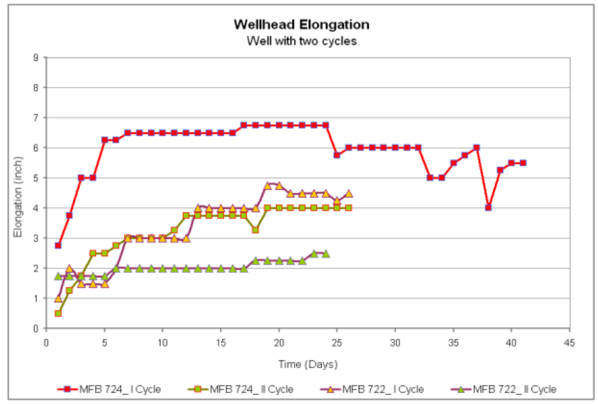

Figure 13: Wellhead Elongation in Wells with Two Steam Injection Cycles

Both wells showed on Figure 13 (MFB-724 and MFB-722) were completed with conventional tubing and nitrogen in the annulus. Wellhead elongations on both wells are less in magnitude from the second cyclic steam when compared to the elongations experienced in the first steam cycle. Table 1 below shows the operational steam injection parameters and field data results.

Operational Parameters	MFB-724 1st Cycle	MFB-724 2nd Cycle	MFB-722 1st Cycle	MFB-722 2nd Cycle
Elongation P-50 (in.)	5.93	3.24	3.38	2.04
Injection Time (Days)	41	26	26	24
Injection Rate (Ton/day)	122	193	193	209
Injection Temperature (°F)	577	498	527	498
Total Injection Volume (Ton)	5,005	5,012	5,015	5,008
Casing Pressure (Psi)	1303	518	700	677

Table 1: Operational Injection Parameters in Wells with Two Steam Injection Cycles

According with the field data analysis of the operational steam injection parameters showed in the Table 1 above, it was observed that on the second cycle the steam injection parameters were higher than the first cycle taking into consideration higher steam injection rates with less injection temperatures and lower casing pressures.

During cyclic steam injection process, the mechanical well structure expands caused by the dilation effect received by the transmitted heat from saturated steam. On the contrary, during the soaking period this effect is different as the well structure suffers a contraction by the cooling effect from its surroundings. If both deformations (dilation and contraction) are produced into the elastic limit of the material, the strain suffer by the well components will not be permanent and will return to the initial conditions. On the other side, if more stress are applied over the elastic limit, the material will have a plastic behavior with permanent deformations and will not return to its original condition when is suspended the stress applied (Maruyama 1990).

When stresses in a well are beyond the yield point (post elastic limit) the molecular structure of the well material changes and thus reduces material deformation for any forthcoming thermal loads. Even though the deformation of the material to new loads will be less the material could reach its maximum yield faster with the consequence of affecting well integrity.

Figure 13 above shows the wells with two cyclic steam jobs deformed exceeding its yield point based on the fact that on the second cycles the elongations were less and as a result affecting its deformation behavior by the thermal loads applied during the first cycle.

CONCLUSION

The low elongations experienced using insulated tubing coincides with the fact that this type of insulation equipment is highly efficient in reducing heat loss during steam injection (Armas *et al* 2015)

The presence of compressive fluids in the annular space with high casing pressure has a direct relation with wellhead elongations since convection heat transfer coefficient in compressed fluids increases with pressure and thus increasing heat influx and proportionally having wellbore deformation.

For repetitive cycles, the wellbore can rapidly reach its yield point due to material fatigue caused by high heat losses resulting excess elongations during the first cycle and decreasing in magnitude thereafter in successive cycles. Wells under conventional tubing and nitrogen in the annulus had loads exceeding the post-elastic limit of the casing material based on low elongations results subsequent to the first steam injection cycle.

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NOMENCLATURE

BFPD – Barrels of Fluid per Day
BSPD – Barrels of Steam per Day
BTU – British Thermal Unit
CSS – Cyclic Steam Stimulation
DTS – Distributed Temperature Sensing
°F – Degrees Fahrenheit
GG - Geothermal Gradient
HC – Heating cable
IT – Insulated Tubing
Lbf - Pounds force
k - Thermal Conductivity Factor (BTU/Ft.-Hr.-°F)
MD – Measured Depth
MI Cable – Mineral Insulated Cable
Tons/D – Tons per Day
Faja - Orinoco Oil Belt
ppf - Pounds per Foot
psi – Pound per Square Inch
TVD – True Vertical Depth
U - Overall Heat Transfer Coefficient
VDL – Variable Density Log

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APPENDIX

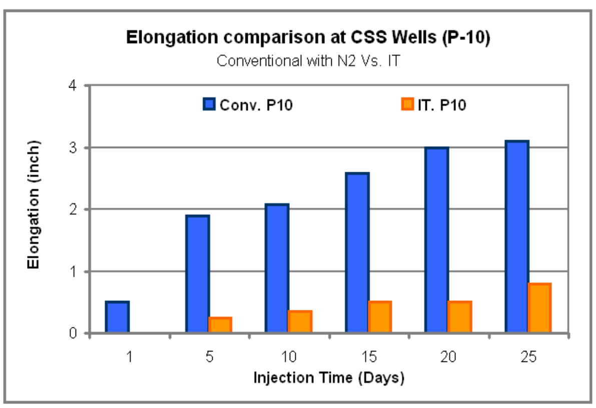

Figure 14: Elongation with respect to Injection Time (P10 Case)

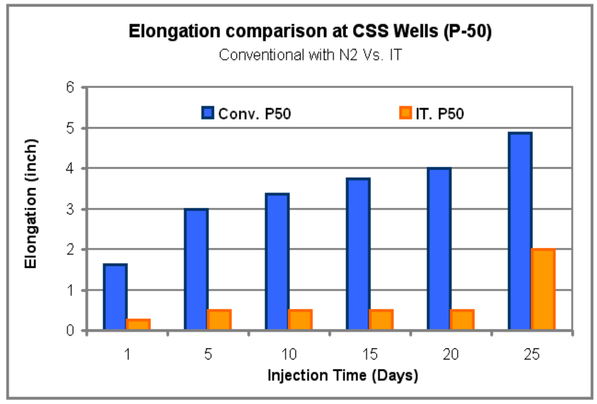

Figure 15: Elongation with respect to Injection Time (P50 Case)

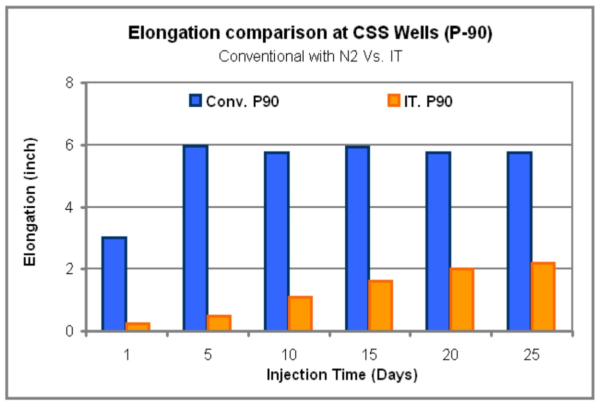

Figure 16: Elongation with respect to Injection Time (P90 Case)