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Wellbore Stability in Ultra-Deep Formations of the Gulf of Mexico

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Wellbore Stability in Ultra-Deep Formations of the Gulf of Mexico

Gbenga Kayode

Thesis submitted to the

Benjamin M. Statler College of Engineering and Mineral Resources at

West Virginia University

in partial fulfillment of the requirements for the degree of

Master of Science

In

Petroleum and Natural Gas Engineering

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Morgantown, West Virginia

2013

Abstract

Wellbore Stability in Ultra-Deep Formations of The Gulf of Mexico

Gbenga Kayode

This thesis work looks into Horizontal wellbore integrity or stability in the Mars Ursa Basin of the Gulf of Mexico using different geo-mechanical properties of this highly producing formation in analyzing stress build up both around the producing wells as well as the producing formations. Different cases were analyzed using the CMG simulator where consideration was given to cases of single as well as multiple producing horizontal wells. The model built considered both the basic reservoir model as well as geo-mechanical models. The individual cases considered included different geo-mechanical properties of the producing formation these properties however include frictional angle, cohesion factor, Young Modulus as well as Poison ratio. Models analyzed involved the effect of these different geo-mechanical properties on the maximum stress in the producing formations as well as salty formations. However for the stress analysis, Mohr Coulomb model was used.

Factors that majorly affected maximum stress mostly were found to be frictional angle and the cohesion factors, formation with higher porosity and permeability having higher production developed higher maximum stress compared to low producing zones also high frictional angle at producing formation resulted averagely into lower maximum stress build up while low frictional angle resulted into higher maximum stress build up. Also formation with high cohesion factor shows higher maximum stress build up while those with low cohesion factor shows lower maximum stress build up.

A general trend however observed in all the cases indicated that whatever geo-mechanical factor or combination of these factors satisfy high production rate will generate higher stress build up both around the wellbore and the producing formation .

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Nomenclature

P.R = Poison Ratio

ϵ = Strain

E = Young's Modulus

ΔL = Change in Length

Ao = Area, acre

Q= Activation Energy for Creep

R= Universal gas constant

T= Temperature

σ_1 or σ_v = Minimum Normal (Vertical) Stress

σ_2 or σ_H = Maximum Horizontal Stress

σ_3 or σ_h = Minimum Horizontal Stress

D= Depth, ft

H= Height or Thickness of formation, ft

R_o = Radius of the reservoir, ft

τ_f = Frictional Stress

μ = Coefficient of Internal Friction

θ = Frictional Angle

NC = Carbon content of hydrocarbon

1.0 Introduction

The Gulf of Mexico has recently become a major oil producing region in the USA and until this date, many discoveries have been made containing an estimated 10 billion barrels of potential resources where about 30 billion barrels are still waiting to be discovered. Fields in the Gulf of Mexico are also highly productive as some major leading oil companies like BP, Shell and Chevron have made some discoveries with production capacity of about 50,150 STB/D from just a single well in the Ursa basin. This discoveries and production from the GOM have really helped boost and increased the amount of oil and gas the United States produces yearly.

Oil and gas production in the Mars Ursa field began early in the year 1996 and came to its peak around 2000 at around 150,000 STB/D of oil and 217 MMSCF/D of gas. This field is expected to still produce for another 50 years. As of 2010, about 24 slot Tension Leg Platform (TLP) have been use in the development of this field while a new TLP are still been planned to increase the number of wells in this field.

The Mars Ursa field consists basically of Miocene to Pliocene turbodite sands deposited within a mini basin, bordered by a canopy or a salt dome which is a good sealing for hydrocarbons and prevent the hydrocarbons from escaping to the seafloor. This field contains about 14 major reservoirs and 10 minor zones. As a result of absence of water influx and highly over-pressured and highly under-saturated reservoirs, the field qualifies as a secondary recovery field. It has good permeability both in horizontal and vertical directions. All these attributes qualifies this field as a major oil producing field in the Gulf of Mexico (GOM).

With all the above mentioned qualities and profit from the ultra-deep oil formation in the Mars Ursa basin as well as some other ultra-deep oil formations in the GOM, there is a challenge in accessing these deep formations as overburden stress increases pressure to around 20,000 psi in some cases. Drilling and producing from these formations poses lots of challenges to the wellbore and life of the well. Therefore there is the need for effective study of the stability of the wells installed in these ultra-high pressured formations.

2.0 Literature Review

2.1 Mars-Ursa Basin

Mars Ursa Basin is predominantly a salt-formation mini-basin and located about 210 kilometers (130 miles) south-southeast of New Orleans, Louisiana on the Northeastern Gulf of Mexico continental slope in about 800-1400 meters (2600 – 4600 ft) of water (Sawyer, 2006). Figure 1 below shows the Mars Ursa location in the Gulf of Mexico.

Figure 1: The Mars Ursa Basin (Moore et. al. 2011)

The Mars Ursa region, geologically a late Pleistocene region originated from deposition from the Mississippian river drainage system. At the East of the Mars Ridge, the seafloor has been observed to slope downward to a zone prevalent of mass transport deposits. These deposits however are characterized by channel-levee systems which filled and bypass the region with thick deposits. From the oldest to youngest and east to west of these deposits are the Ursa, Southwest Pass, Old Timbalier and Young Timbalier systems (Sawyer, 2006). This channel levee system has been the major factor that aided the transportation of material from the continental margin to the Mississippian fan.

2.1.1 Mars Ursa Reservoir Properties

Two basic intervals were considered in the study. First the Above-magenta formations as well as the Lower-yellow formation as these intervals were found to be rich in hydrocarbons.

The “Above magenta” formation was interpreted to be an amalgamated channel (Meckel et. al. 2002).The reservoir occurs as a sheet channel couplet in the continuous parallel facies and also characterized by a relatively high porosity while the lower yellow formation is characterized by channels cutting through it. The channels connect two major reservoirs and possess relatively high porosity value. Figures 2 and 3 below show gamma ray, resistivity as well as porosity values in these different formations that is under consideration.

Figure 2: Well- log data for the Above Magenta Reservoir Interval (Batzel et. al. 2006)

Figure 3: Well- log data for the Lower Yellow Reservoir Interval (Batzel et. al. 2006)

Vertical permeability values in the Mars Ursa basin is found to be around $7.7 \times 10^{-17} \text{ m}^2$ (0.0780 md) and $8.5 \times 10^{-19} \text{ m}^2$ (0.0086 md) while horizontal permeability values were found to correspond with porosity and ranges from around 10^{-3} md to 10^2

md (Julia et. al. 2012). Figure 4 shows the general in-situ characteristic of relationship between porosity and permeability in the formation.

Figure 4: Porosity and Permeability Relationship at the Mars-Ursa Basin (Gulf of Mexico)
(Reece et. al. 2012)

Pressure:

Values of pressure in the Mars Ursa basin are so high and close to fracture pressure gradient. This is due to a thick accumulation of fine grained, low permeability sediment that was deposited rapidly and subsurface drainage was inadequate for

excess pore pressure to dissipate. This led to the overpressured zones at the shallow part of the Mars Ursa Basin. Figure 5 below shows overpressured zones at the Mars Ursa Basin.

Figure 5: Mars Ursa Formation Pressure (Overpressured zone) (Batzel et. al. 2006)

2.1.2 Mars Ursa Rock Properties

Rock properties are very essential to analyze geomechanical effects in the formation as well as around wellbore after years of producing. Basically, geomechanical properties of any rock formation are obtained through well logs and these properties include Young's Modulus, Cohesion, Poisson's ratio and Frictional Angle. All these factors are used in this study to estimate the maximum stress build up in the formation as well as around each well in the course of production.

Poisson's Ratio

Poisson's ratio is related to elastic moduli (K), Bulk modulus, the shear modulus and the Young's Modulus (E). Basically, Poisson's ratio is ratios of the relative contraction strain, or transverse strain normal to the applied load, to the relative extension strain or axial strain in the direction of the applied load.

Mathematically this expression can be shown as

$$\text{Poisson's Ratio } (\nu) = \frac{\varepsilon_t (\text{Transverse Strain})}{\varepsilon_l (\text{Longitudinal or Axial Strain})} \text{-----Eq 1}$$

$$\text{Strain } (\varepsilon) = \frac{dl (\text{change in length})}{L (\text{Initial Length})} \text{-----Eq 2}$$

Young's Modulus

Young's modulus is otherwise referred to as the tensile modulus or elastic modulus and is a measure of the stiffness of a material (elastic). It is basically expressed as the ratio of uniaxial stress or tensile stress over the uniaxial strain or tensile strain. Mathematically we can express the Young's Modulus (E) term as

$$E = \frac{\text{Tensile Stress}}{\text{Tensile Strain}} = \frac{\sigma}{\varepsilon} = \frac{F/A_o}{\Delta L/L_o} = \frac{FL_o}{A_o \Delta L} \text{-----Eq 3}$$

Cohesion

The term cohesion defines the status of rocks based on fusion of minerals or cementing of grains in sediments and it can result from electrostatic forces among fine

particles especially clay and water. However, in geomechanics, cohesion occurs when cemented surfaces are sheared. Using the Mohr Coulomb Circle, cohesion is determined as the intercept on the Shear stress (τ) axis at zero normal stress.

For this study, we have used ranges of cohesion between 2×10^7 Pascal (2800 psi) and 4×10^7 Pascal (5800 psi) in estimating the maximum stress developed in the formation.

Frictional Angle

Frictional angle is a measure of the shear strength of materials including rocks, and sand and simply defined from the Mohr- Coulomb failure. It is the angle of inclination with respect to the horizontal axis of the Mohr Coulomb shear resistance line.

For this study, frictional angles in the range of 15° to 35° were used to calculate the maximum stresses that will develop in the formation.

2.2 Effect of Salt in GOM Oil Formations:

Hydrocarbon deposits in the Gulf of Mexico are basically under salt diapirs. They occur in multitiered sheets which are interconnected by vertical and inclined salt feeders. A major concern or a major hazard in a salty formation like the Mars Ursa Basin is that they can creep when subjected to stress. This effect of pseudoplastic flow caused by overburden pressures, and combined with temperature in the subsurface with low permeability may close up or collapse a new wellbore.

Salt creep involves two or three stages. When the confining pressures are less than 5 Mpa (725 psi) where strain begins at a very high rate and then decreases to a

constant rate. The second stage is as a result of salt deforming at a constant rate and during the third stage, the strain rate increases until failure occurs. (Perez et. al. 2008), Factors that are responsible for salt creep behavior include salt thickness, mineralogy, water content and impurities. Salt creep has been responsible for casing collapse in a number of Gulf of Mexico wells.

Geomechanics' study of salt formations should be able to state the type of rock or mineral present in the particular rock salts as the minerals present are major factors that determine creep strain rates, solubility and temperature response of the formations. For example Halite is a type of rock salt that has a lower creep rate compared to tachydrite ($\text{CaCl}_2 \cdot 2\text{MgCl}_2 \cdot 12\text{H}_2\text{O}$). The double mechanism creep law which is based on elastic and visco elastic behavior of a salt formation has been used in creep strain rate calculation.

$$\dot{\epsilon} = \dot{\epsilon}_o \left[\frac{\sigma_{ef}}{\sigma_o} \right]^n \cdot \exp \left(\frac{Q}{RT_o} - \frac{Q}{RT} \right) \text{----- Eq 4}$$

Deformation of salt formation is a result of yield stress; the yield stress however varies with temperature and confining pressure in the formation. At high confining temperature and pressure, rock salt deforms and act in a plastic manner. Creep is the rate of flow of visco-elastic materials at all stress values and as long as the stress even at values less than the elastic limit) is applied on these materials for a significant amount of time the material will flow (Omojuwa et. al. 2011).

The relationship between viscosity and temperature is a direct one as viscosity decreases with temperature and increases as temperature increases. Different models

have been used in estimating stresses, strains and strain rates in salt formations; these include Von Moses Criterion, octahedral-stress theory and Maxwell linear creep equations.

$$\sigma(\text{mean stress}) = \frac{1}{3} (\sigma_1 + \sigma_2 + \sigma_3) \text{ --- Eq 5}$$

$$\tau_o(\text{octahedral shear stress}) = \frac{1}{3} \sqrt{(\sigma_1 - \sigma_2)^2 + (\sigma_1 - \sigma_3)^2 + (\sigma_2 - \sigma_3)^2} \text{ --- Eq 6}$$

$$\epsilon_e(\text{elastic strain}) = \frac{\sqrt{2}}{3} \sqrt{(\epsilon_1 - \epsilon_2)^2 + (\epsilon_1 - \epsilon_3)^2 + (\epsilon_2 - \epsilon_3)^2} \text{ --- Eq 7}$$

The mean stress measures the tension or compression a particular body is subjected while octahedral shear stress measures the deformation stress a body is undergoing and the elastic strain is that in which a distorted body returns to its original shape of form when the deformation is removed. Combination of all these stresses are needed in estimating the total stress as well as strain that will develop in formations with salt during production period.

2.2 Effect of Depleted Sand Formations on Wells in GOM

Although salt formations contribute to the major challenge of wellbore instability in deep hydrocarbon formations in the Gulf of Mexico, another factor that causes wellbore instability mainly during drilling operations is when drilling through regions whose pore pressures have been reduced by offset production to a value lower than that existing at discovery. The reduction in pore pressure is mainly as a result of reduction in horizontal stress. This effect however is well recognized from hydraulic fracture treatments in fields that have been in production for certain amount of time

(Willson et.al.2003). Reduction in fracture gradient has always been a problem in drilling these formations and has caused losses of several barrels of mostly oil-based drilling fluids. (Willson et.al. 2003). This problem is usually addressed by augmenting the fracture gradient using loss reducing additives as well as chemical consolidation of the depleted sand zones.

2.3 Reservoir Properties of Salty Formation

A major characteristics of rock salt is it's low porosity in the range of less than 0.5% to 1% while permeability values are about 10^{-20}m^2 (about 10 nanodarcy). This property has been a major factor helping rock salt in acting as a long term storage facility for oil and gas (hydrocarbons). Low permeability and porosity properties are however also causes of tendency for plastic and creep behavior even at low stress levels.

Low permeability values in salt formations are a major cause of overpressure as this (low permeability) effect prevents pore fluids in the underlying formation from escaping and as a result they become trapped and abnormally pressured (over-pressured). Salty formations also absorb surrounding stresses from above layers and transferring these in three directions to achieve equilibrium. This however always leads to increase in horizontal stresses in values greater than or equal to overburden stress. Thus, for wellbores around or close to salty formations like the Mars Ursa Basin, there is the need to use highly rated and collapse resistant casings.

According to (Yildiz and Soganci 2010), layers of sediments in salt formations are graded from hard (at the bottom) to soft (at the top). The layers are separated from each

other with interfaces thereby creating weaker connections between the top layers and stronger connections at the bottom layers.

2.4 Challenges in the Deepwater (Mars Ursa basin)

A major characteristic of the deepwater Gulf of Mexico hydrocarbon formation is the presence of overpressured reservoirs. Sedimentation rate exceeds the ability of sediments to drain in rapidly formed basins. This as a result causes overpressure in pore fluid as it supports overlying materials and sediment is under-consolidated. (Flemings et. al. 2002). Over-pressured and unconsolidated factors in these formations often result to highly compacting reservoirs generating significant natural reservoir drive as well as fluid expansion and water influx.

Drilling these very deep hydrocarbon formations is a major challenge as some of these hydrocarbon layers have been found at depths close to around 28000 ft to 34,158 ft. Drilling to these depths encounter very high pressure and temperature (HP/HT) conditions (Lach 2010). Another major challenge in the Mars Ursa Basin also was drilling closely spaced holes while preventing fracturing or weakening of the formation as well as being able to keep the drilled holes open long enough before the installation of casings.

2.5 Geographical Impact of Producing Hydrocarbon Formations (Land Subsidence)

Production of hydrocarbons in the coastal regions of the United States have been known to induce faults into surrounding formations where hydrocarbons are produced and this has always led to land subsidence . A case study on the Louisiana coast was

done recently and results proved that induced- seismic activity occurred in these formations as a result of sub-surface fluid injection as well as hydrocarbon withdrawal. The study demonstrated that the number of seismic events in proximity of producing oil or gas field increases significantly after production or injection began (Chan and Zoback 2007)

The study indicated that mechanical instability which is induced as result of fluid injection is related to the increase in pore pressure. This however allows for slip on pre-existing faults which is caused by lowering the effective normal stress. As shown in Figure 6 below, slips on these faults leads to faults in formation.

Figure 6: Schematic of deformation surrounding a depleting reservoir (Segall 1989)

Geertsma (1972) developed a solution relating to land subsidence as a result of producing hydrocarbons from underground formations shown below

$$u_z(r, 0) = -2c_m (1 - \nu) \Delta P_p H A(\rho, \eta) \text{-----Eq 8}$$

η and ρ are dimensionless parameters ,

$$\text{and } \rho = r/R \text{-----Eq 9}$$

$$\text{also } \eta = \frac{D}{R} \text{-----Eq 10}$$

Where D, H and R are the depth, thickness and radius of the reservoir, respectively.

u_z is the magnitude of surface subsidence while ΔP_p is a function of pressure change.

The equation presents the relationship for the amount of subsidence observed in any producing formation as related to changes in pressure, depth, thickness and radius of drainage of the producing formation. This however shows the effect of these other parameters on the would-be subsidence.

Depletion or removal of hydrocarbons from producing formations also leads to changes in stresses around the reservoir and as a result, slip on faults outside the reservoir may result. The stress change however leads to fault reactivation in the proximity of the reservoir and eventually to reverse faulting either above or below the reservoir column while normal faulting occurs near the edge of the reservoir. (Chan and Zoback 2007).

2.6 Geomechanics

Geomechanics is the geologic study of rocks and soil behaviour when subjected to different stress conditions. Basically this involves soil mechanics as well as rock mechanics. While soil mechanics deal with the behavior of soil from a small scale to a landslide scale, rock mechanics deal with geosciences relating to rock mass characterization as well as rock mass mechanics.

The state of equilibrium in any rock formation is always disturbed by drilling, production and injection of fluids at certain high pressures. These activities always

result in changes in the mechanical state of these rocks and can impact drilling operations, completions infrastructure as well as quality and quantity of hydrocarbon production from these formations.

2.7.1 Subsurface Stress

Stresses acting on any particular formation vary in origin, magnitude and direction. Natural, in-situ vertical stresses occur primarily from the weight of overburden. Horizontal stresses have gravitational components that are enhanced by tectonics thermal effects and geological structure. Factors that can also influence stresses in any formation include the lithology, pore pressure and temperature. Stress, force acting on an area is made up of normal and shear components. Normal stress is that acting perpendicularly to a plane or rock surface shown in figure 7 below, shear stress is that acting along the surface of the plane. Magnitude as well as orientation of stress in the earth change with the structural dip of the formation, faults, salt diapirs, mountains and other complex structures can also be responsible for this phenomenon. As continued deposition leads to greater depth of burial, overburden stress increases. This always lead to a situation where the horizontal stress changes causing the formation to spread out laterally but these changes (deformation) are always confined by adjacent formations.

Figure 7: Vertical , maximum and minimum horizontal stresses (Cook et. al. 2007)

A rock body responds to stress from various modes of strain or deformation which results in different changes from volume to shape as well as properties of the rock. The different stages of change (deformation) range from reversible (elastic deformation) to permanent (plastic deformation) before eventually ending up in the failure stage of the rocks. Deformation resulting from compression can lead to compaction, extension, translation or rotation and eventually ends up in the shearing, fracturing or faulting stage as seen in Figures 8 and 9 below. Rock's response to these stresses also depends on some other factors including rock type, cementation, porosity, and depth of burial.

Figure 8: Stages of in formation(rock) Deformation (Cook et .al. 2006)

Figure 9: Formation states based on applied stresses (Cook et. al. 2006)

2.7.2 Mohr Coulomb Yield Criterion

For rocks, soils and concrete, inelastic deformation occurs as a result of frictional sliding over the plane of shearing and the normal stress over that plane affects the yield. This is referred to as the Mohr-Coulomb Yield Criterion.

Failure occurs if the Mohr's circle corresponding to the stress state based on $\sigma_1, \sigma_2, \sigma_3$ values of maximum vertical stress, minimum and maximum horizontal stresses touch the Mohr's envelope shown in Figure 10 as a failure line (envelope).

Figure 10: The Mohr Circle with failure envelope (Hooke and Hansen 2005)

Where

$$\tau_n = \tau_f + c, \quad \tau_f (\text{Frictional Stress}) = -\mu^* \times \sigma_n$$

$$\mu^* = \tan \phi,$$

ϕ , angle of internal friction and c is cohesive strength of the material

μ^* = Coefficient of friction

Stress values relating to points at which the failure line represented by equation of a straight line ($\tau_n = C - \mu^* \sigma_n$) touches the circle indicates stresses at which the particular material will fail or collapse.

3.0 Methodology

The objective of this research was to conduct geomechanical analysis in wells drilled in the ultra-deep zones of the Gulf of Mexico. Wellbore stability based on maximum stress build up around the wellbore as well as in the formation is the major concern addressed in this study. The Gulf of Mexico has been known to contain large hydrocarbon reserves but majority of these are below zones buried under salt formations due to salt's ability to exhibit characteristics of low permeability and acting as a very good seal for hydrocarbons in such ultra-deep zones. Although field production data was not readily available, reservoir data used for the model were obtained from different published articles and sources.

Major steps applied in obtaining the required results include acquiring data, building the reservoir model as well as the geomechanical model and running the simulation cases for each well in the reservoir. The simulation was run using the CMG program for thirty years in order to understand the long term effect of the salty sealing formation around the wellbores as well as production decline for each case being considered.

3.1 Data

Using inaccurate data may be a major hindrance in obtaining accurate result from the simulation runs; therefore there is the need to conduct extensive and broad research in obtaining accurate data that fully and readily represent the model as well as the formation under investigation. Majority of the wells in the Mars Ursa basin were drilled by Shell PLC and data for these wells are not readily available so other sources were used in obtaining these data. Sources mostly used were those from papers

published by AAPG (American Association of Petroleum Geologist) and SPE (Society of Petroleum Engineers) about the Mars Ursa Basin.

Logs (Batzel et. al. 2006) were used in obtaining porosity, permeability as well as hydrocarbon thickness used at different sections of the reservoir model. For the geomechanical model, rock properties were obtained from geomechanical logs.

3.2 Reservoir and Geomechanical Model

Both reservoir and geomechanical models were built and used for the simulation runs. The reservoir was built first and then the geomechanical model was coupled to the reservoir model for geomechanical analysis. Of major importance to the reservoir model are rock and fluid data, well data, thickness data as well as porosity and permeability data.

3.2.1 The Reservoir Model

Based on data from the Mars Ursa Basin the reservoir model was developed with fourteen layers in which the major hydrocarbon producing layers were located in layers two, three, eleven and thirteen. Wells named as “Well #1”, “Well #2”, “Well #3” and “Well #4” were placed into layers “2”, “3”, “11” and “13” respectively. The top most layers are basically the shallow hydrocarbon formations while the bottommost are basically the very deep formations well below the salt layers.

The cell block dimensions for the model were basically squares of 167 ft on each side with a length of approximately 5000 ft by 5000 ft for the entire reservoir. Horizontal

length for each well in the reservoir formation extended up to 4500 ft where each cell block was perforated.

For this study, a deep formation was chosen to represent formations where the pressure is extremely high and also close to the salt formation to account for the effect of the overlying salt formation on the stress build up around the wellbore. Thickness of formation at the sections of the reservoir at shallow part of the reservoir is around 70 ft while at the very deep section is around 60 ft (Batzel et. al.2006).

Permeability and porosity values are considerably high in the Mars Ursa Basin which is common in the Gulf of Mexico. This formation does not require fracking before production and as a result, fracking was not considered in this study. Porosity values in the formation range from around 10% to 35% while permeability values range from around 10 md to 50 md in the oil producing formations. In the salt formation, permeability value is extremely low around 10 nD (Omojuwa and Osisanya 2011). The study also considered the use of horizontal wells as this is the prevailing situation in the Mars Ursa Basin (Anderson & Boulanger 2001).

A horizontal well length of around 4500 ft was used in this study for stress build up around the wells close to the salt formation. More focus is placed on geomechanical analysis and wellbore length and some other properties were kept constant. All the cell blocks (30) along the I-axis covering the horizontal leg length of the wellbore were perforated to have the maximum hydrocarbon production from the wells. Wellbore radius of 0.25 ft and bottom hole pressure of 100 psi were used in all runs.

Considering the reservoir composition, a range from very heavy hydrocarbon of 5% n-C₁₀, 5% n-C₇, 20% n-C₄ and 70% “CH₄” (Methane) was used in the model as this reservoir combines both liquid or heavy oil and gas. Water saturation value of 35% was used for the reservoir model. The Pressure in the Mars Ursa Basin is extremely high in the overpressure zones and this has always been a major concern during the drilling program. The pressure values in hydrocarbon formations close to shale or salt formation could rise as high as 12000 psi to around 15000 psi (Meckel et.al. 2002). In this study, 12000 psi was used to represent the over-pressured regions or formations in the evaluation of stress build up in the reservoir.

The frictional angle values used range between 15° to 35° while cohesion factor range between 2500 psia to around 5800 psia. The poisson's ratio used for salt, shale and sand formations were 0.25, 0.3 and 0.2 respectively. Young Modulus values were also varied accordingly to the formations where 6.00E+09 Pa is used for sandy formations, 8.00E+09 Pa (11.5 x 10⁴psi) is used for shales and 3.10E+09 Pa (5.13x10⁴psi) is used for salt .

The data used in the runs are summarized in Table 1

Formation	Young's Modulus(Pa)	Poisson Ratio	Cohesion (Psia)	Friction Angle (degrees)
Sand	6.00E+09 Pa	0.2	2500-5800	15°-35°
Shale	8.00E+09 Pa	0.3	2500-5800	15°-35°
Salt	3.10E+09 Pa	0.25	2500-5800	15°-35°

Table 1: Geomechanical Parameters used in this study

4.0 Results and Discussion

Based on the results obtained from simulation runs, it is observed that geo-mechanical properties of oil bearing formations have a significant impact on stresses around the wellbore as well as in the surrounding formations. It was also observed that areas or regions close to the salty formations showed considerable high stress development around them compared to other formations. A significant factor that could also increase maximum stress build up around the well is the amount of fluid produced. As observed, those “stress” levels increases as production increases. Four wells located at different depths were considered in this study and runs were conducted with four different values of cohesion and frictional angles.

Table 2 below shows the results for maximum stress levels obtained from the simulation after with different cohesion and frictional angle values for Well #1 at the end of 30 years of production.

Cohesion Values (Psia)	Stress (Psia)			
	Fric Ang = 15	Fric Ang = 25	Fric Ang = 30	Fric Ang = 35
0	9644	9624	9601	9550
2900	9658	9647	9628	9600
4350	9675	9662	9641	9622
5800	9690	9672	9662	9636

Table 2: Impact of cohesion and friction angle on maximum stress for Well #1

Table 2 shows the maximum stress values for Well #2 with four different values of cohesion and frictional angle. Tables 2 and 3 for Wells #1 and #2, show that stress increased significantly with increase in cohesion but decreased as frictional angle increases. The stress values exhibit significant difference for shallow and deep wells.

This observation is believed to be related to the rapid deposition resulting in thick layers of fine grained and low permeability sediments.

Cohesion Values (Psia)	Stress (Psia)			
	Fric Ang = 15	Fric Ang = 25	Fric Ang = 30	Fric Ang = 35
0	9440	9432	9424	9422
2900	9520	9503	9448	9438
4350	9570	9560	9452	9445
5800	9576	9569	9459	9450

Table 3: Impact of cohesion and frictional angle on maximum stress for Well #2

Table 4 shows the maximum stress values for Well # 3 similar to Well # 1 and #2. The stress values observed for Well #3 were less than the ones observed for Wells #1 and #2. Well #3 is closest well to the salt formation and the effect of salt is observed as the minimum stress build up possibly due to the absorption of some disturbances by the salt formation.

Cohesion Values (Psia)	Stress (Psia)			
	Fric Ang = 15	Fric Ang = 25	Fric Ang = 30	Fric Ang = 35
0	7508	7491	7488	7485
2900	7515	7510	7499	7490
4350	7948	7935	7901	7892
5800	7951	7939	7920	7900

Table 4: Impact of cohesion and frictional angle on maximum stress for Well #3

Table “5” tabulates results for maximum stress values for Well #4. The Well #4 is located at the deepest part of the formation also exhibited the same increasing stress

similar to Wells #1, #2 and #3. When results from Well #4 are compared to Well #3, the maximum stress values were observed to be higher for Well #4.

Cohesion Values (Psia)	Stress (Psia)			
	Fric Ang = 15	Fric Ang = 25	Fric Ang = 30	Fric Ang = 35
0	8450	8434	8421	8407
2900	9256	9245	9232	9222
4350	9272	9263	9245	9234
5800	9286	9274	9252	9246

Table 5: Impact of cohesion and frictional angle on maximum stress for Well #4

Generally, it was observed from the simulation results that frictional angle and cohesion doesn't really affect the amount of fluid or gas produced from the producing formation but rather that production has an effect on the maximum stress that develops in these formations. The well located directly under the salt formation shows lower stress values compared to those at the very shallow part of the reservoir. A possible reason for this can be associated to the geology of the Mars Ursa Basin where overpressures have been reported due to quick deposition of sediments. The shallow part of the Mars Ursa Basin has been known as a site of mass transport deposits as shear stress of this part of the formation far exceeds the shear strength. This event occurs in formations as a result of sediments rapidly depositing, this causes overpressure in these formations thereby decreasing the strength of the sediment. Geotechnical studies including in-situ pore pressures measurements established the presence of pressures significantly above hydrostatic within the shallow strata of the Mars Ursa Basin (Ostermeier et. al. 2000).

Another major factor to consider here is the effect of overburden stress where it can be observed that stress on Well #4, the deepest well in this reservoir showed a significantly high level of stress build up compared to that of Well #3. Therefore, depth of burial is also a major factor that can affect stress around the wellbore. The highest maximum stress value around 9690 psi was however observed around Well #1 situated at the shallow part of the reservoir while the minimum value was recorded around Well #3 just below the salty, Lower Magenta formation layer.

Figure 11 shows stress values with frictional angle of 15° . It indicates the continuous level of stress build up around the wellbore from initial stage of production where stress values significantly increased up to fifteenth years of production then increased at a very minimal rate for the rest production period. Therefore this proves the influence of production on stress build up in the formation.

Figure 11: The stress build-up for case frictional angle 15° Cohesion "0"

The frictional angle 30° used in the study also indicates similar trend as shown in Figure 12. The stress build up increased significantly within the first fifteen years of production but leveled off after fifteen years and remained constant for the rest of production. This trend of stress increase is parallel to the cumulative production as shown in Figure 13 for Wells #1 and #2. However, cumulative gas production continually increased beyond year 15 for Wells #1 and #2 as shown in Figure 14.

Figure 12: The stress build-up for case frictional angle 30° Cohesion 0 psia

Figure 13: The Cumulative Oil Production for Well #1 and #2 (frictional angle 15)

Figure 14: The Cumulative Gas Production for Wells #1 and #2 (frictional angle 15)

Figures 15 and 16 shows the cumulative oil and gas production, respectively for Wells #3 and #4 where production continually increased contrary to Wells #1 and #2. However stress build up trend was similar to the Wells #1 and #2

Figure 15: The Cumulative Oil Production for Wells #3 and #4 (frictional angle 15)

Figure 16: The Cumulative Gas Production for Wells #3 and #4 (frictional angle 15)

When a frictional angle of 30° was used, similar trends were observed for Wells #1 and #2 in Figures 17 and 18. Figures 19 and 20 show the cumulative oil and gas production for Wells #3 and #4.

Figure 17: The Cumulative Oil Production for Wells #1 and #2 (frictional angle 30)

Figure 18: The Cumulative Gas Production for Wells #1 and #2 (frictional angle 30)

Figure 19: The Cumulative Oil Production for Wells #3 and #4 (frictional angle 30)

Figure 20: The Cumulative Gas Production for Wells #3 and # 4 (frictional angle 30)

In general, the build up around production wells follow similar trend for all wells. Wells #1 and #2 reach peak stress within the first fifteen years of production and then stabilized. For Wells #3 and #4 closer to the Magenta (salt) formation, the stress values continue to increase as hydrocarbon production continues. The Well #3, closest to the magenta (salt) formation is observed to exhibit the increasing trend at a higher level when it is away from the magenta formation.

Figure 21 compares the maximum stress values obtained for all wells where the values of frictional angle and cohesion were varied. The values of maximum stress increases with increasing cohesion values but decreases with increasing friction angle values.

The comparisons of maximum stress values are shown in Figure 22 for Well #2. The increasing trends for maximum stress were same as the Well #1 but there was a significant increase in stress values when the frictional angle was reduced from 30 to 25. It appears that the values of frictional angle play a critical role in determining the maximum stress values for Well #2.

Figure 21: The Stress Values for different frictional angles (Well #1)

Figure 22: The Stress Values for different frictional angles (Well #2)

Figure 23 compares the results for maximum stress values for Well #3. The behavior of maximum stress values showed similar trends similar to Wells #1 and #2 but there was a big jump in the values when Cohesion values were changed from 2900 psia to 4350 psia

Figure 23: The Stress Values for different Cohesion Values (well #3)

The results for maximum stress values for Well #4 is shown in Figure 24 the trend was similar to Well #3 but the significant increase was observed when the cohesion value of 2900 or higher is used.

Figure 24: The Stress Values for different Cohesion Values (Well #4)

Figure 25 shows the stress distribution in the second of x-y plane for Well #1 at the end of ten years with a cohesion value of 0 psia and frictional angle value of 15° . Figures 26 and 27 also show the same distribution at the end of 20 and 30 years respectively. In Figure 25, stress levels increased up to 7737 psia covering up to about 1166.7 ft away from the wellbore. Figure 26 also shows the same trend where stress increased up to 9690 psia covering a length of about 666.4 ft away from the wellbore, also other sections of the formation have exhibited up to 8714 psia increase in stress.

Figure 25: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #1 (After 10 Years)

Figure 26: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #1(After 20 Years)

Figure 27 shows that with frictional angle value of 15 and cohesion value of 0 psia, the 9690 psia maximum stress profile have covered up to 1660.7 ft away from the wellbore. Other sections of the formation have witnessed up to 8714 psia increase in stress.

Figure 27: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #1 (After 30 Years)

The results for stress distribution for Well #3 with cohesion value of 0 psia and frictional angle 30° in layer 11 and on the x-y plane after 10 years of production is shown in Figure 28. The stress has risen up to 4733 psia covering a distance of about 1283.7 ft away from the wellbore.

Figure 29 shows that stress level rose to about 6342 psia covering a distance of about 1166.9 ft away from the wellbore after twenty years of production. Figure 30 for

Well #3 also shows the same trend after thirty years of production where stress build up around the wellbore has risen up to 7951 psia just covering a distance of 166.7 ft while other parts of the formation have seen a stress build up of about 7147 psia.

Figure 28: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #3 (After 10 Years)

Figure 29: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #3 (After 20 Years)

Figure 30: Stress profile for case frictional angle 15 Cohesion 0 psia for Well #3 (After 30 Years)

Similar trend of increase in production for the first fifteen years and a decline in production for the second fifteen years is observed for all the wells used in this study under different frictional angle and cohesion values. Wells #3 and #4 showed a slightly different behavior as it was observed that these two wells still maintained increase in production beyond the first fifteen years. The results are shown in Figures 31 through 62 in the appendix.

Figures 63 through 74 in Appendix show the results of stress profiles at the end of 10, 20 and 30 years of production when frictional angles ranged from 15° to 35° for all wells used in this study. Based on results, lower frictional angles of 15° and 25° are seen to have impacted a larger area in the formation compared to frictional angles of 30° and 35° . The results were similar for all the wells both above and below the magenta salt formation. Well #4 was observed with a slightly different stress profile compared to that of Well #3. When a frictional angle of 15° was used, the stress distributions covered a wider area compared to other frictional angle values used in the study.

Similarly, the stress distributions at the end of 10, 20 and 30 years of production are shown for all wells in Figures 75 through 90 with cohesion values of 0, 2900, 4350 and 5800 psia. The impact of cohesion was significant as maximum stress profiles increased both in width and length with increase in cohesion values. In some cases width and length covered showed similar profiles for cohesion values of 4350 and 5800 psia. We attribute this behavior to the high cohesion factor above a certain threshold

that do not cause an increase in the maximum stress value in the formation based on geomechanical and reservoir characteristics.

5.0 Conclusions

The basic aim of this research was to determine the impact of oil and gas production on integrity and stress distribution for horizontal wellbores producing in highly over-pressured formations like that in the Mars Ursa Basin, Gulf of Mexico. Based on the results obtained from the simulations the following conclusions were made:

- ✚ The overall magnitude of stress build up in these formations is related to the frictional angle and cohesion factor. The results show that the higher frictional angle results in lower stress buildup around the producing wellbore while higher cohesion factors resulted in higher stress buildup.
- ✚ As a result of hydrocarbon production, stress builds up in the formations around the wellbore. The stress build up is quite significant during the first fifteen years of production but the stress build up stabilizes for all wells studied when the cumulative hydrocarbon production reaches a plateau.
- ✚ Formations close to salt diapirs experienced longevity in production and also lower stress build up as the effect was more felt in layers a bit more distant to these salt layers. However, salt effect therefore might not be felt in the early life of the well, but in areas close to their deposits and in layers a little further from their deposits.
- ✚ The impact of the over-pressurized formations on stress at shallow depths of Mars Ursa Basin is more significant. This is evident for Wells #1 and #2 as higher stress is built up in these layers as compared to other wells studied.

✚ The well designs for the Mars ura Basin should consider the stress build up during the first 15 years. Once properly designed to withstand this early stage of production, the wellbores' integrity will not be compromised.

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Appendix

Figure 31: Cumulative Oil Production for Cohesion 0 psia of Well #1

Figure 32: Cumulative Gas Production for Cohesion 0 psia of Well #1

Figure 33: Cumulative Oil Production for Cohesion 2900 psia of Well #1

Figure 34: Cumulative Gas Production for Cohesion 2900 psia of Well #1

Figure 35: Cumulative Oil Production for Cohesion 4350 psia of Well #1

Figure 36: Cumulative Gas Production for Cohesion 4350 psia of Well #1

Figure 37: Cumulative Oil Production for Cohesion 5800psia of Well #1

Figure 38: Cumulative Gas Production for Cohesion 5800psia of Well #1

Figure 39: Cumulative Oil Production for Cohesion 0 psia of Well #2

Figure 40: Cumulative Gas Production for Cohesion 0 psia of Well#2

Figure 41: Cumulative Oil Production for Cohesion 2900psia of Well #2

Figure 42: Cumulative Gas Production for Cohesion 2900 psia of Well #2

Figure 43: Cumulative Oil Production for Cohesion 4350 psia of Well #2

Figure 44: Cumulative Gas Production for Cohesion 4350 psia of Well #2

Figure 45: Cumulative Oil Production for Cohesion 5800 psia of Well #2

Figure 46: Cumulative Gas Production for Cohesion 5800 psia of Well #2

Figure 47: Cumulative Oil Production for Cohesion 0 psia of Well #3

Figure 48: Cumulative Gas Production for Cohesion 0 psia of Well #3

Figure 49: Cumulative Oil Production for Cohesion 2900 psia of Well #3

Figure 50: Cumulative Gas Production for Cohesion 2900 psia of Well #3

Figure 51: Cumulative Oil Production for Cohesion 4350 psia of Well #3

Figure 52: Cumulative Gas Production for Cohesion 4350 psia of Well #3

Figure 53: Cumulative Oil Production for Cohesion 5800 psia of Well #3

Figure 54: Cumulative Gas Production for Cohesion 5800 psia of Well #3

Figure 55: Cumulative Oil Production for Cohesion 0 psia of Well #4

Figure 56: Cumulative Gas Production for Cohesion 0 psia of Well #4

Figure 57: Cumulative Oil Production for Cohesion 2900 psia of Well #4

Figure 58: Cumulative Gas Production for Cohesion 2900 psia of Well #4

Figure 59: Cumulative Oil Production for Cohesion 4350 psia of Well #4

Figure 60: Cumulative Gas Production for Cohesion 4350 psia of Well #4

Figure 61: Cumulative Oil Production for Cohesion 5800 psia of Well #4

Figure 62: Cumulative Gas Production for Cohesion 5800 psia of Well #4

Figure 63 : Stress profiles after 10 years for Well #1

Figure 64 : Stress profiles after 20 years for Well #1

Figure 65 : Stress profiles after 30 years for Well #1

Figure 66 : Stress profiles after 10 years for Well #2

Figure 67 : Stress profiles after 20 years for Well #2

Figure 68 : Stress profiles after 30 years for Well #2

Figure 69 : Stress profiles after 10 years for Well #3

Figure 70 : Stress profiles after 20 years for Well #3

Figure 71 : Stress profiles after 30 years for Well #3

Figure 72 : Stress profiles after 10 years for Well #4

Figure 73 : Stress profiles after 20 years for Well #4

Figure 74 : Stress profiles after 30 years for Well #4

Figure 75 : Stress profiles after 30 years for Well #1 with frictional angle 15

Figure 76 : Stress profiles after 30 years for Well #1 with frictional angle 25

Figure 77 : Stress profiles after 30 years for Well #1 with frictional angle 30

Figure 78 : Stress profiles after 30 years for Well #1 with frictional angle 35

Figure 79 : Stress profiles after 30 years for Well #2 with frictional angle 15

Figure 80 : Stress profiles after 30 years for Well #2 with frictional angle 25

Figure 81: Stress profiles after 30 years for Well #2 with frictional angle 30

Figure 82: Stress profiles after 30 years for Well #2 with frictional angle 35

Figure 83: Stress profiles after 30 years for Well #3 with frictional angle 15

Figure 84: Stress profiles after 30 years for Well #3 with frictional angle 25

Figure 85: Stress profiles after 30 years for Well #3 with frictional angle 30

Figure 86: Stress profiles after 30 years for Well #3 with frictional angle 35

Figure 87: Stress profiles after 30 years for Well #4 with frictional angle 15

Figure 88: Stress profiles after 30 years for Well #4 with frictional angle 25

Figure 89: Stress profiles after 30 years for Well #4 with frictional angle 30

Figure 90: Stress profiles after 30 years for Well #4 with frictional angle 35

Wellbore Stability in Ultra-Deep Formations of the Gulf of Mexico

Thesis submitted to the

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