Sudan University of Science and Technology
College of Petroleum Engineering and Technology
Department of petroleum Engineering

Effect of Steam Parameters and Injection Schedule on Cap-rock Integrity during CSS -Case Study, FNE, Sudan

تأثير خصائص البخار وجدولة الحقن على سلامة الغطاء الصخري للمكمن خلال عمليات الحقن الدوري للبخار دراسة حالة FNE السودان

Research submitted to College of Petroleum Engineering & Technology in partial fulfillment of the requirements for the B.Sc. (Hones) Degree in Petroleum Engineering

Prepared by:

- Basil M. Hussain
- Islam Masoud A Abdurrahman
- Mohammed Almunthir Hashim
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This Research is approved by College of Petroleum Engineering and Technology to petroleum Departmentof Petroleum Engineering

Project Supervisor...

Signature..

Head of Department...

Signature...

Dean of College...

Signature...

Date: / / 2022

الإستـهلال

قال تعالى:

بسم الله الرحمن الرحيم

{ ولقد آتينا داوود وسليمان علما وقالا الحمد لله الذي فضلنا على كثير من

عباده المؤمنين }

سورة النمل الآية (15)

DEDICATION

We dedicate this project to our parents for the love and support they have provided throughout our entire life, they have been there for every decision we have made and help our dreams become reality, to our friends and families for their help and encouragement.

In addition, we dedicate this research to our colleagues in petroleum engineering department, and all batch petroleum engineering Students.

.

شكر وتقدير

قال تعالي (وَمَن يشكُرُ فَإِنَّما يشكُرُ لنَفسِهِ) {لقمان :12}

وقال رسوله الكريم :من لا يشكر الناس لا يشكر الله عز وجل

نحمد الله تعالي حمداَ كثيراَ طيباَ مباركاَ ملء السموات والأرض علي ما أكرمنا به من إتمام هذه الدراسة التي نرجو أن تنال رضاه.

سنشد عضدك باخيك لذا نتوجه بجزيل الشكر وعظيم الإمتنان الي:

الأخ :عثمان كمال لمجهوده ولما قدمه من عطاء وتوجيه.

والأخ الزميل: محمد يحي لما بذله من نصح وتوجيه.

ABSTRACT

Production of hydrocarbons from geological reservoirs, and injection of fluids into geological strata are accompanied with stress changes in the reservoir and in the cap rock. If the stress changes are large enough, they may reactivate faults or pre-existing natural fractures, or induce new fractures in the reservoir and/or the cap rock. Fractures in the cap rock may threaten the cap rock integrity, while fractures within the reservoir may increase its injectivity.

This work is studied the cap rock integrity and effect of the different CSS injection parameters on cap rock failure through FNE field in which steam flooding and CSS are used as a major EOR method in the field.

Using (CMG) Computer Modeling Group and geo-mechanical concepts with iterative two-direction coupling for reservoir rock and fluids properties, many scenarios were conducted to study the effect of steam injection schedule in the rock deformation and cap rock interiority. Anderson's method were used to estimate the mechanical properties. Injection rate of 500, 750 and, 1000 m^3/day were studied under constant steam volume of 144 m^3, and steam temperature of 255^oC with steam quality of 0.8 and 0.85. Elasto plastic Mohr–Coulomb was selected as the rock type model and the deformation observed from the normal effective stress which decreases with the of injection rate.

The yield state was used as an indicator for fracture initiation as used in CMG. An injection rate of 750 m^3/day can insure cap rock integrity while 1000 and 1500 m^3/day will perform fracture in the caprock at different operations days; also, the time that the fracture can be initiated in early when compared to that of 1000 m^3/day. water production increases with the injection rate as the aquifer will fractured at early time when the he injection rate is high.

Keywords: Cyclic Steam Stimulation, Geo-Mechanics, Cap Rock Failure, Injection Rate, Steam Quality

التجريد

يترافق إنتاج الهيدروكربونات من المكامن الجيولوجية وحقن السوائل في الطبقات مع تغيرات إجهاد في المكمن وفي صخور الغطاء. إذا كانت تغيرات الإجهاد كبيرة بما يكفي ، فقد تكون شقوق أو تمدد شقوق طبيعية موجودة مسبقًا ، في المكمن أو صخرة الغطاء. قد تهدد الشقوق في صخر الغطاء سلامة صخر الغطاء ، بينما الشقوق داخل الخزان قد تزيد من معدلات الحقن بها

في هذا العمل تمت دراسة صخور الغطاء وتأثير معاملات الحقن الدوري للبخار المختلفة على انهيار صخور الغطاء في حقل بالسودان FNE حيث يتم استخدام الغمر البخاري و الحقن الدوري للبخار كطريقة رئيسية للاستخلاص المعزز للنفط في هذا الحقل

.باستخدام مجموعة النمذجة الحاسوبية (CMG) والمفاهيم الجيو ميكانيكية مع اقتران تكراري ثنائي الاتجاه لصخور المكمن وخصائص السوائل ، تم إجراء العديد من السيناريوهات لدراسة تأثير جدول حقن البخار في تشوه الصخور والغطاء الداخلي للصخور. تم استخدام طريقة أندرسون لتقدير الخواص الميكانيكية. وتمت دراسة معدلات الحقن 500 ، 750 و ، 1000 م 3 / يوم تحت حجم بخار ثابت قدره 144 الف م 3 ، ودرجة حرارة بخار 255 درجة مئوية بجودة بخار 0.8 و 0.85. وقداستخدم الإجهاد الفعال الطبيعي الذي يتناقص مع معدل الحقن.لدراسة التشوهات تم استخدام مرحلة الخضوع كمؤشر لبدء الانهيار .

واثبتت الدراسة معدل الحقن 750 م 3 / يوم يمكن أن يضمن سلامة صخور الغطاء بينما 1000 و 1500 م 3 / يوم سوف تؤدي إلى انهيار في صخور الغطاء في أيام العمليات المختلفة ؛ أيضا فان الانهيار يحدث مبكرا عند استخدام معدل حقن 1500 م 3 / يوم بالمقارنة مع 1000م 3/ يوم. كما ان إنتاج الماء مع معدل الحقن يزداد حيث يتشقق الخزان الجوفي في وقت مبكر عندما يكون معدل الحقن مرتفعًا

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Chapter 1

General Introduction

1.1 Introduction

The heavy oil is a general terminology for liquid petroleum with an API gravity of less than 20° or more than 200 cp viscosity at reservoir conditions; the API gravity, is a measure of how heavy or light a petroleum liquid is compared to water. If its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. As a rule of thumb (Amyx et. al -1960), the crude oil is grouped into:

1. Light oil: with an API more than 31.1.
2. Medium oil: with an API between 22.3 and 31.1.
3. Heavy oil: in which API is less than 22.3.
4. Extra heavy oil (bitumen): in which API is less than 10 (the oil would sink, rather than float in water).

Another classification was based on crude viscosity (Table 1); Speight et.al (1991) classified the crude oil based on viscosity into 4 different categories:

1. Light oil: which has low viscosity (less than 50 mpa.s) .
2. Common heavy oil: which has a viscosity range between 50 to 10000mpa.s
3. Extra heavy oil: with a viscosity range of 10000-50000 mpa.s
4. Super heavy oil: with a viscosity above 50000 mpa.s .

Conventional oil comprises a small fraction of hydrocarbons in sedimentary basins and it uses primary recovery production (Water drive, Solution gas drive, Gas cap drive, Gravity drainage, and Fluid and rock expansion) however, it will decline gradually. On the other hand, Hydrocarbon resources of heavy oil and oil sands are nearly three times the conventional oil in-place in the world. According to

Farouq Ali and Meldau (1999) over two trillion barrels of oil is present in the oils sands (less than 12°API gravity and greater than 10000 cp) of Alberta and in Canada the contribution of heavy oil and oil sands resources is 20% of the total oil production. Nevertheless, it is not recoverable in its natural state through a well by ordinary production methods and other types of recovery are required. Generally, heavy oils and tar sands respond poorly to primary and secondary recovery methods. Before 1985, heavy-oil production was based largely on thermal stimulation to reduce viscosity and large pressure drops to induce flow these include: Cyclic steam stimulation (CSS -huff 'n' puff), Steam flooding (SF), Wet or dry combustion with air or oxygen injection (Tarek Ahmed, 2017).

One of the most common problem associated with heavy and sands oil is the sand production of the shallow depth unconsolidated formation. , the stresses caused by fluids flowing into the wellbore are often sufficient to cause fine particles to be agitated. In turn, the throttling effect caused by these particles lodging in pore throats near to the wellbore redirects the fluid flow pattern, thereby altering the direction and magnitude of the stress fields. This leads to additional particles being dislodged. Once the destabilizing forces exceed the formation strength, increased sand production follows. The viscosity of the moving fluid is major factor affecting the movement of this sand. The thermal EOR method such as CSS when injecting steam into reservoir can results in change of in situ stresses, rock properties, porosity, permeability, wettability and capillary pressure. Geomechanical understanding of reservoirs subjected to CSS can help in understanding issues like low injectivity, reservoir drive and cap rock integrity. (Temizel,et. al, 2015). The thermal method (CSS and SF) mainly decrease the viscosity of fluid which is reduce sanding potential during the production up to a point; with the production the temperature decrease lading to increasing in viscosity which returned to the first step of the sanding potential; and when starting heating again, sanding decreases and the new cycle of production started when cooling achieved and so on. The thermal method includes injecting steam into the well; Cyclic steam stimulation consists of injecting steam into the production well at a relatively high injection rate for a period (known as injection period) followed by shutting in the well for a few days (known as socking period) and then the well is put on production till it reaches the economic flow rate at which the cycle should be repeated. Optimization of the working periods (injection, socking and production), and steam quality are the major factors affecting the job succeeding and many scenarios needed to those factors. At late stages of production period sand produces and high water cut as a result of fluid re-cooling due to production; which uses as indicator for starting the new cycle

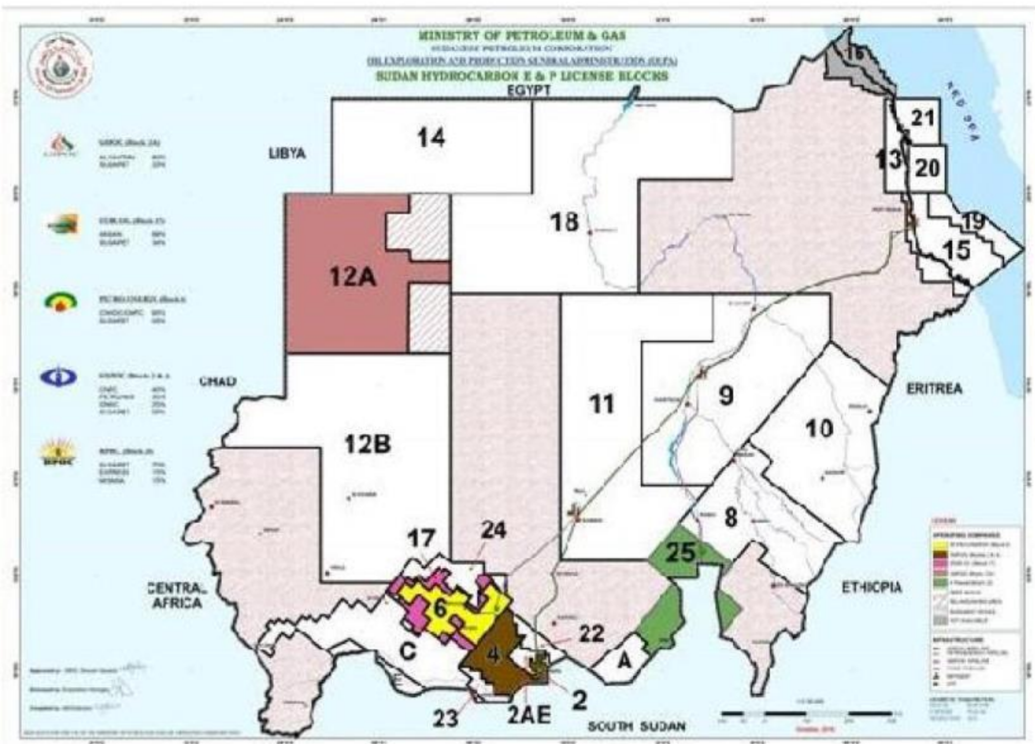
1.2 General Background about the Field:

Fula North East (FNE) field is located in the East of Fula -basin, southwest of Sudan, 10 km north east from existing Fula North Field see figure 1.3 which established on October, 2010.

FNE Field is shallow heavy oil reservoir with good hydrocarbon concentrate in small area, which has three productive sand intervals, named “Bentiu”, “Aradeiba”, and “Abu Gabra”, With normal Faults, and has clear oil/water contact (OWC) system in “Bentiu” formation, FNE oilfield produces high viscous crude oil from productive sand interval, (Bentiu) massive sand formation, sands in this formation had average initial oil saturation of 50%. Average porosity is 27% and permeability range from 1 to 10 Darcie’s, however the oil density of 10 to 17.9-degree API and viscosity of 3791.5 cp, combined with low initial reservoir temperature (44ºC) and (576psi) average reservoir pressure result in low primary recovery. The Total wells as per Oct, 2016 are 100 wells. Through which Cold production wells are 18 wells, hot production wells are 78 wells and steam injector are4 well.

Fula North East field is a medium size heavy oil field at shallow depth of 550-600 m. Bentiu sand is the main oil-bearing formation which holds more than 90% of STOIIP.

Oil fields like FULA North East where oil gravity is low or viscosity is more than3000 cp at reservoir conditions and is unfavorable for conventional methods of recovery, thermal recovery is the best technique for maximum ultimate oil recovery.



Fig(1-1): FULA North East Field (Ministry of Petroleum & Gas 3, years)

Screening study was carried out which suggest that reservoir and fluid characteristics of FULA North East field are most suitable and favorable for steam based enhanced oil recovery processes (Taber, Martin, & Seright, 1997; Dios, Dickson, & Wylie, 2010). The viscosity of oil will decrease with increased temperature and reduce the drag force in the formation and make fluid flow easy in the formation. Oil mobility also improves with heating, resulting into increase in oil rate. A thermal process also reduces the residual oil saturation thus increases the moveable oil volumes and better sweep efficiency obtained at higher temperature.

CSS pilot tests on two wells began in 2009; convincible results have been monitored with well daily rate 3-4 times of cold production wells with low water cut. Another six CSS wells further came on stream from July 2010 achieving similar positive results.

1.3Problem statement:

The type of heavy oil reservoir in FNE field is complex, steam flooding and CSS are used as a major EOR method in the field. The field suffering from massive water production, which can result from steam breakthrough or water coning or bottom-water movement. Many researches were conducted to study the effect of the injection parameters and the steam quality in the produced water. Some studies neglecting the effect of geo mechanics; while other considering geo mechanics; however, all those studies was not consider the cap rock failure. This work is aim to study the cap rock integrity and effect of the different CSS injection parameters on cap rock failure.

1.4 Objective:

The main objective of this work is to study the effect of the real applied CSS parameters in the water production for some a well in FNE under different conditions considering reservoir Geomechanics and cap rock failure; which include:

1) Estimating the dynamic rock mechanics properties using Anderson’s Equation.
2)Studying the effect of Steam parameters in cap rock failure different conditions
3)Studying the effect of injection schedule in cap rock failure under different conditions.

Chapter 2

Theoretical Background and Literature Review

Introduction

Ronald. E (2001) states that "EOR is characterized by injection of special fluids such as: chemicals, miscible gases and /or the injection of thermal energy".Teknica (2001) states that " EOR Refers to any method used to recover more oil from a reservoir than would not be obtained by primary recovery ".The injected fluids must accomplish several objectives as follows (Green & Willhite, 1998).

1. Boost the natural energy in the reservoir
2. Interact with the reservoir rock/oil system to create conditions favourable for residual oil recovery that include among others
3. Reduction of the interfacial tension between the displacing fluid and oil
4. Increase the capillary number
5. Reduce capillary forces
6. Increase the drive water viscosity
7. Provide mobility-control
8. Oil swelling
9. Oil viscosity reduction
10. Alteration of the reservoir rock wettability

The ultimate goal of EOR processes is to increase the overall oil displacement efficiency, which is a function of microscopic and macroscopic displacement efficiency. Microscopic efficiency refers to the displacement or mobilization of oil at the pore scale and measures the effectiveness of the displacing fluid in moving the oil at those places in the rock, where the displacing fluid contacts the oil (Green & Willhite, 1998). For instance, microscopic efficiency can be increased by reducing capillary forces or interfacial tension

2.2 Thermal methods:

Thermal methods have been tested since 1950's, and they are the most advanced among EOR methods, as far as field experience and technology are concerned. They are best suited for heavy oils (10-20° API) and tar sands (≤10° API). Thermal methods supply heat to the reservoir, and vaporize some of the oil. The major mechanisms include a large reduction in viscosity, and hence mobility ratio. Other mechanisms, such as rock and fluid expansion, compaction, steam distillation and breaking may also be present. Thermal methods have been highly successful in Canada, USA, Venezuela, Indonesia and other countries.

Table 2.1 Screening Criteria for Different Thermal EOR Methods (*Taber et al.,1997*)

Criteria / Method	API	Viscosity cp	Oil Saturation	Formation type	Thickness ft	Permeability md	Depth ft	Temperature °F
Steam Flooding	10-25	<10,000	>40	Sandstone with high permeability	>20	>200	<5000	Not critical
CSS	<22	>100	>40	Sandstone with low clay	>20	>200	<5000	Not critical
ISC	10-27	<5000	>50	Sandstone with high porosity	>10	>50	<12000	>100

2.2.1. Cyclic Steam Stimulation (CSS):-

Cyclic steam stimulation is a "single well" process, and consists of three stages. In the initial stage, steam injection is continued for about a month. The well is then shut in for a few days for heat distribution, denoted by soak. Following that, the well is put on production. Oil rate increases quickly to a high rate, and stays at that level for a short time, and declines over several months.

Cycles are repeated when the oil rate becomes uneconomic. Steam-oil ratio is initially 1-2 or lower, and it increases as the number of cycles increase. Near wellbore geology is important in CSS for heat distribution as well as capture of the mobilized oil. CSS is particularly attractive because it has quick pay out, however, recovery factors are low (10-40% OIP). In a variation, CSS is applied under fracture pressure recovery factors are low (10-40% OIP). In a variation, CSS is applied under fracture pressure.

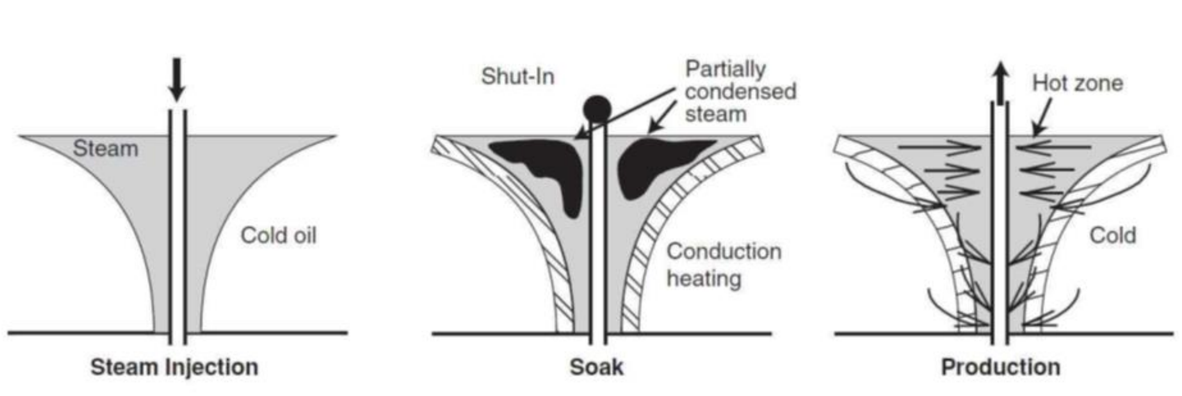


Fig2.1 Cyclic Steam Stimulation (CSS) (S Thomas, 2008)

I. Injection Phase

It's the first step which by it a cycle of CSS begins to operate where an amount of hot steam must be injected into a certain well for a small duration (2 to 4 weeks) and by the increment of the reservoir temperature, the viscosity of thecrude is always decreases (Temperature is directly proportional with the viscosity) which helps in getting more initial oil rate.

II. Soaking Phase: -

During soaking, the well is closed for a certain short duration (2 to 4 days) which is selected precisely making the chamber expands by extending of the steam and allowing the steam to reach to further possible point in the formation to heat a bigger possible area. The soaking time is a sensitive phase affected by the fluid's properties, as the soaking period decreases, the ratio of the produced oil to that oil in place increases.

Due to the gravity segregation and heat transfers the crude oil after the heat distribution takes place led to decrease in crude oil viscosity. Into heat transfer process considered that the segregation happened by convection process between two fluids with different densities.

III. Production Phase: -

The oil which is heated by the hot injected steam is forced to go down in the reservoir according to the density differences and gravity segregation effect and due to the variety in the pressures inside the well which will produce. After that, the well will start to produce this oil. By injection of the hot steam, many zones have been heated and its degree of temperature will be large affecting inthe initial oil rate which will become higher. By passage of time, more oil willbe produced and that high degrees of temperature in the heated zone willdecrease leading to the decline of that initial rate.

The increment of the temperature is followed by the decrement of viscosityof the crude oil which leads to a high enhancement in the oil producing rate when comparing with the production without CSS. The variety in pressures andthe gravity segregation effect is combined together to represent the two essentials mechanism in the cyclic steam injection to induce oil.

1-The most important mechanism is viscosity reduction because oftemperature increasing. The Fig 2.5 shows specific changes in viscosity. It isknown that the more viscous fluid, the more resistance to flow vice versa asviscosity decrease, the flow will be easier and oil flows at higher rate.

2- Wettability changes associated with CSS is a secondary mechanism to enhance oil recovery; the increase of temperature affect wettability to become more water-wet; because of high PH number and low salinity injected steam converted into thin water layer which adhere to rock surface and prevent oil contact with rock; wettability changes allow more oil saturations to flow through the porous to increase oil production rate and prevent water flowing to avoid high water cut.

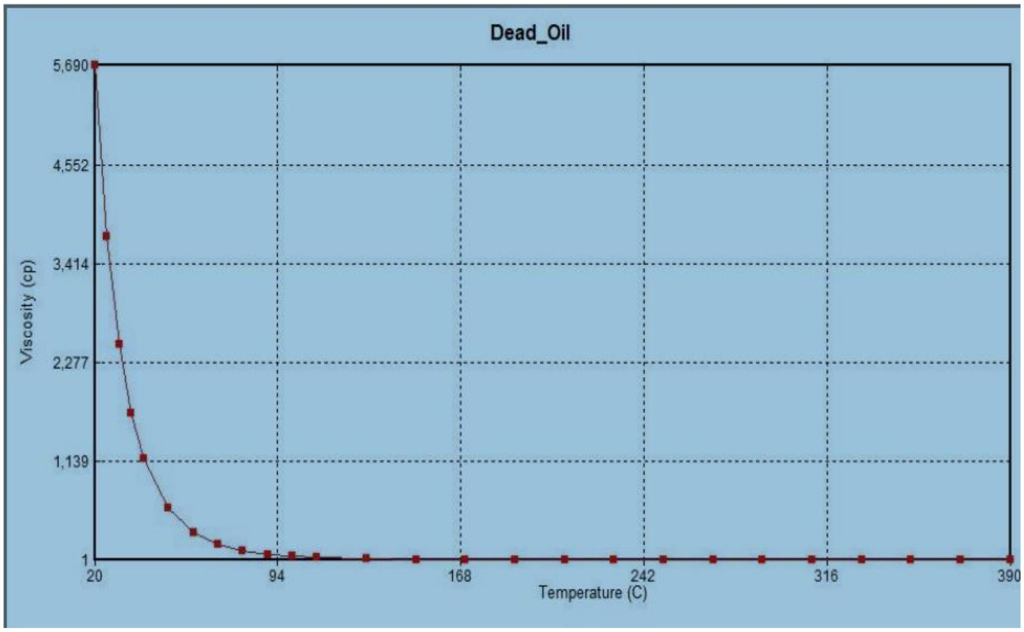


Fig 2.2 Cyclic Viscosity VS Temperature Relationship (Wu, ET, 2013)

3-There are many other mechanisms (e.g., gas expansion) but their impacts are negligible compared to viscosity reduction and wettability alteration.

The previous mechanisms working together to give high production in the beginning of each cycle then the oil rate declining till reach an economic limit at this point the production period ends and new cycle initiated, cycles repeated till becoming unprofitable.

CSS technique has been applied in many fields all over the world such as Bolivar Coastal and Santa Barbara in Venezuela, Cold Lake Oil Sands in Canada, Xinjiang in China, San Joaquin Valley of California in USA and in other heavy oilfields around the world. In 2015 in Kuwait, Quttainah et. al presented that in case of wells producing heavy oil with considerable sand production and that undergo cyclic steam stimulation the challenge is often at the end of the production cycle.

While the oil is thin and has good viscosity, the sand settles itself at the bottom. However, with time as the oil gets colder and thereby heavier, it carries the sand along with it to the surface causing plug in the flow line. This is due to the high viscosity of the oil.

This is believed to be the end of production period beyond which it would have been impossible to produce any further even after sand clean up. Certain operational procedures were established to ensure the integrity of the down-hole equipment and to avoid the failures. It has been observed that by effective sand monitoring it was possible to determine the next injection cycle with more accuracy.

Zeng and Zhang (2016) Using simulation models compared isothermal conditions and those of heated/cooled formations conditions; they presented that sanding zone may be increased by heating up the wellbore but producing sand is a wellbore temperature decrease process, leading to a smaller temperature gradient, less sanding producing drive and less incremental sand production instead.

Although of its impact in reduction oil viscosity by 28 to 42% (Hongfu et. al-2002), a series of problems are associated with steam injection due to steam breakthrough or channeling which an important source of excessive water productions and seriously affect the field production (Johnson et. al -2004, Wang and Zhang -2011). Transmission of unconsolidated particles, intensity well pattern, the thermal cracking of asphalt, cementing material solubility, the changes of tectonic stress field besides steam overlapping (Dong et al., 2012) are the major factors affecting steam breakthrough or channeling

CSS was applied also in Sudan since 2011; Wang et. al (2011) describe the first CSS pilot test in Sudan has been designed on a robust basis and implemented with success in 8 wells. Pilot wells of FNE-38 and FNE-16 have been selected for CSS. Well FNE-38 shows that, totally 21940 tons of oil has been produced during the first CSS cycle (2009) which is 3 to 4 times of CHOPS production. Also, well FNE-16 shows cumulatively 16235 tons of oil has been produced up to end of Feb. 2011. which is 3 to 5 times of CHOPS production.

Comparison of cold production wells with cycle steam stimulation wells in Fula North East oilfield (FNE) presented that cold production wells are producing higher sand compare to. CSS wells and recommended to replace cycle steam stimulation with cold production in the field (Abdala et. al, 2016).

In 2017, Sharif et .al, studied the effect of steam volume variation through different cycles on the amounts of sand and oil been produced by the end of each cycle in cyclic steam stimulation (CSS) wells through Fula North East oilfield (FNE), to understand the production behaviour of those wells and relate injected steam volume with those two major parameters. They found that, no relationship between steam volume and sand production. Also, the sand production quantity in CSS wells basically depends on soaking period, more soaking time means formation temperature gets low, crude becomes colder, and more sand is expected to flow after well start-up.

In 2018 Qiuguo et al. studied the impact of mechanical property variations on reservoir and caprock failure through geo-mechanical simulations; the study presented that higher steam injection pressures significantly increase the risk of caprock failure. The maximum operating pressure should be determined based on the results of geomechanical simulations.

Geomechanical concepts combined with reservoir modeling to estimate the temperature distribution inside the reservoir to be used as indicator for sanding potential during cyclic Steam Stimulation process(CSS) In FNe 17 through Fula north east field in Sudan (**Hafizet. al 2018**). Different injection rate was studied to present its effect on the temperature distribution under constant steam quality, temperature, and amount for injection rate of 100, 150, 200, 288, and 300 m3/day.

The result presented that low injection rate decreasing the temperature distribution which decreasing the required production period.

Heat Distribution in Rock Layers:

When a hot fluid “gas, liquid” or a mixture of the two is injected into anoil-bearing porous medium, heat is transferred to the rock matrix and interstitialfluid. Such heat transfer is primarily due to conduction and convection, as the steam enters the reservoir, there is some heat loss in the wellbore due to the transition of heat to the overburden and under burden adjacent non-productiveformations, Fig 2.3.The amount of heat reaching the reservoir during the steam injection is essentially a function of the steam injection temperature and well-bore heat losses.

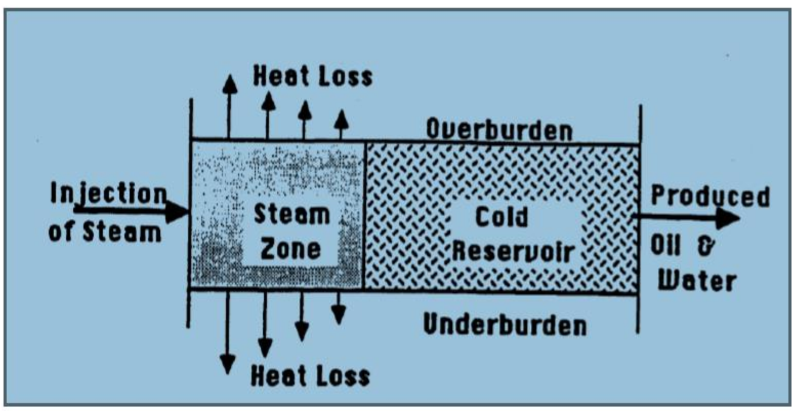


Fig 2.3 Heat Distributions in the Rock (Farooq Ali Jones 1997)

$$Q = f(T_s, Q_{loss}) \quad (2.1)$$

Where:

Ts = steam injection temperature.

Qloss = well-bore heat losses.

Historically, many different models were presented for heat distribution inside the rock; Marx and Langenheim (1959) developed a model to predict the growth of the steam zone in the reservoir during steam injection into a single well with the assumption of No gravity effects, no hot water flow ahead of condensation front, Sufficient Pressure Drop and mobility of reservoir fluids to allow steam injection exact rate and constant injection rate. In Marx and Langenheim's model, the principal shortcoming is that it does not account for conduction and convection ahead of the condensation front; also, it does not properly account for the effect of steam quality.

These limitations do not exist for the numerical simulators. Nevertheless, they can be relatively easily addressed by means of two theories which were developed to improve the ML calculation. The theory of Mandl and Volek (1969) assumes that until a critical injection time is reached the steam condensation front (CF), although always slowing due to heat losses, leads the convective heat flow and tends to sharpen the conductive temperature profile ahead of the front. At the critical time all the latent heat of injected steam is used to supply heat losses from the steam zone to cap and base rock and to provide the latent heat content of the steam zone. After the critical time the convective heat flow due to condensate leads the steam condensation front, until this critical time is reached, the original ML theory is suitable (although conduction ahead of the CF is ignored by both theories). After the critical time, the propagation of the CF is calculated by an approximate formula presented by Mandl and Volek.

Boberg and Lantz (1966) developed another model to calculate the average temperature of the heated region with time as heat flows from the heated disk into the overburden and under burden by conduction during the soak and production period. The main considerations in the model are that the reservoir pressure as the main driving mechanism for oil production; the gravity drainage is ignored; and the steam zone is assumed to propagate radially outward from the wellbore. The average temperature is calculated taking into account the heat losses in radial direction, vertical direction and due to production of hot fluids.

Other Methods of predicting the steam zone shape were presented by Neuman (1975) and van Lookeren (1983); model to include steam overlay as well as steam vent rate and conditions at both injection and production wells were presented by Hsu (1992). The method of van Lookeren, which gives a shape factor based on the steam injection rate to characterize the tilted steam/liquid interface, is especially convenient in making calculations. The equations were validated with scaled, physical models. For less viscous oils, the sloping steam zone interface may prove to be stable.

2.2.2. Steam Flooding:

Steam flooding is a pattern drive, similar to waterflooding, and performance depends highly on pattern size and geology. Steam is injected continuously, and it forms a steam zone which advances slowly. Oil is mobilized due to viscosity reduction. Oil saturation in the swept zone can be as low as 10%. Typical recovery factors are in the range 50-60% OIP. Steam override and excessive heat loss can be problematic

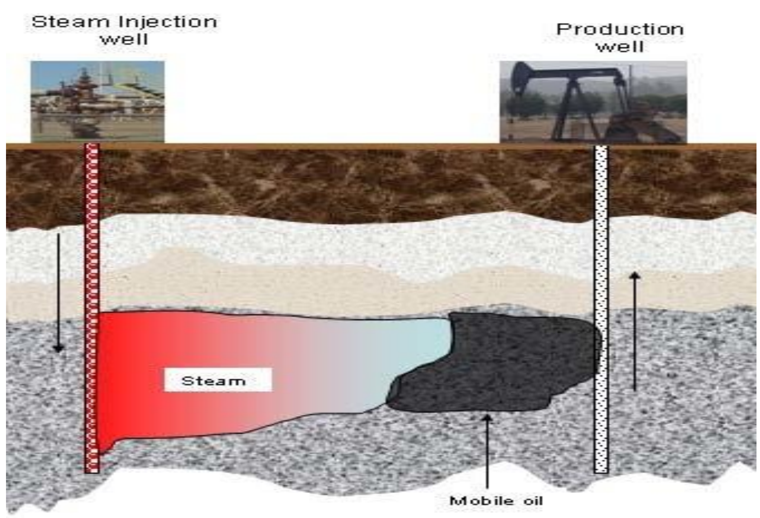


Figure (2.4) Steam flooding

2.2.2. Steam Assisted Gravity Drainage (SAGD):

SAGD was developed by Butler for the in-situ recovery of the Alberta bitumen. The process relies on the gravity segregation of steam, utilizing a pair of parallel horizontal wells, placed 5 m apart (in the case of tar sands) in the same vertical plane. The top well is the steam injector, and the bottom well serves as the producer. Steam rises to the top of the formation, forming a steam chamber. High reduction in viscosity mobilizes the bitumen, which drains down by gravity and is captured by the producer placed near the bottom of the reservoir. High vertical permeability is crucial for the success of SAGD. The process performs better with bitumen and oils with low mobility, which is essential for the formation of a steam chamber, and not steam channels.

SAGD has been more effective in Alberta than in California and Venezuela for the same reason.SAGD is highly energy intensive. Large volumes of water are required for steam generation, and the natural gas consumption for steam generation ranges between 200- 500 tonnes/sm3 of bitumen. There had been several attempts to improve the economics of SAGD. Notable examples among SAGD variations are ES-SAGD, and SAGP

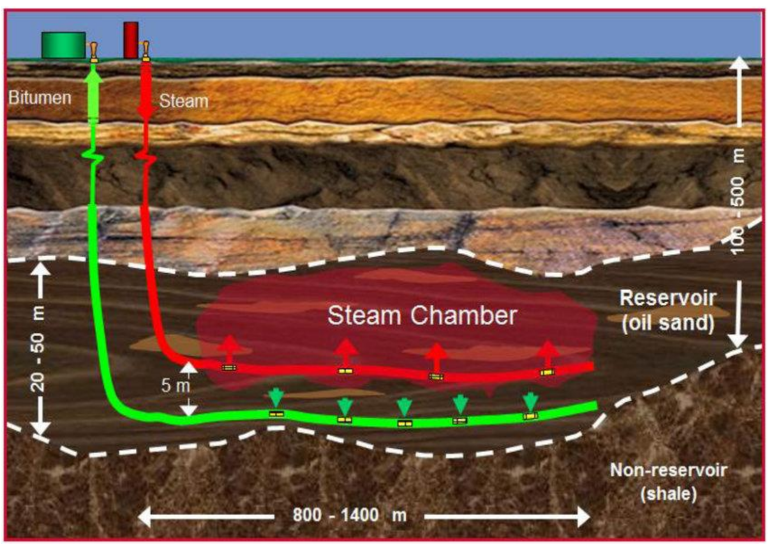


Figure (2.5) Steam Assisted Gravity Drainage (SAGD)

2.2.3. In Situ Combustion:

In this method, also known as fire flooding, air or oxygen is injected to burn a portion (~10%) of the in-place oil to generate heat. Very high temperatures, in the range of 450-600°C, are generated in a narrow zone. High reduction in oil viscosity occurs near the combustion zone. The process has high thermal efficiency, since there is relatively small heat loss to the overburden or under burden, and no surface or wellbore heat loss. In some cases, additives such as water or a gas is used along with air, mainly to enhance heat recovery. Severe corrosion, toxic gas production and gravity override are common problems. In situ combustion has been tested in many places, however, very few projects have been economical and none has advanced to commercial scale.

The main variations of in situ combustion are:

1) Forward combustion

2) Reverse combustion,

3) High pressure air injection.

In forward combustion, ignition occurs near the injection well, and the hot zone moves in the direction of the air flow, whereas in reverse combustion, ignition occurs near the production well, and the heated zone moves in the direction counter to the air flow. Reverse combustion has not been successful in the field because of the consumption of oxygen in the air before it reaches the production well. High pressure air injection involves low temperature oxidation of the in-place oil. There is no ignition

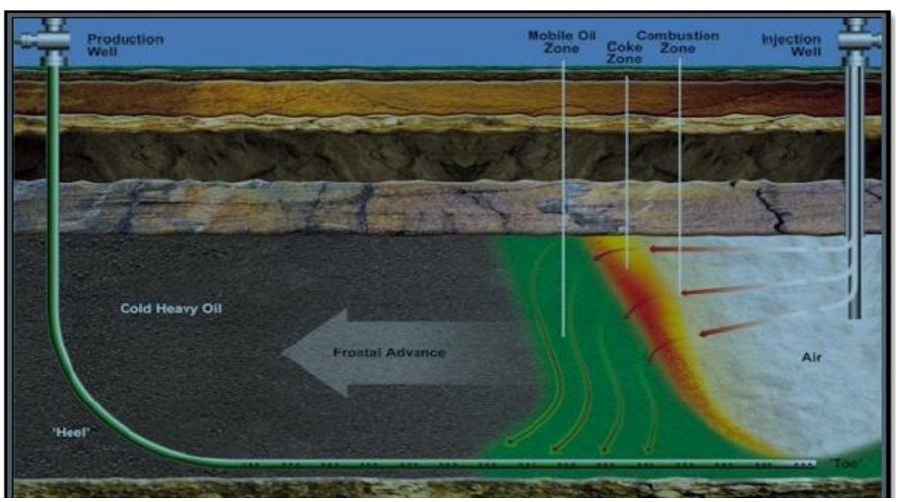


Figure (2.6) In Situ Combustion (Jelmert, T .er.all,2010)

2.3 Stresses in Reservoir and Cap Rock during EOR

2.3.1 In-situ Stresses

For radial coordinates the stress relationships assuming plain strain and elastic behavior, the principal stresses on a rock element located at the wellbore interface has a three components Fig (2.2) can be computed as:

$$\sigma_z = \sigma_V + 2\mu(\sigma_1 - \sigma_2) \quad \text{(2.3)}$$

$$\sigma_\theta = 3\sigma_1 - \sigma_2 - P_{wf} \quad \text{(2.4)}$$

$$\sigma_r = P_{wf} \quad \text{(2.5)}$$

The vertical stress (σv) is equal to the overburden pressure and typically calculated from the density logs as follows:

$$\sigma_v = g\int_0^D \rho dz \quad \text{(2.6)}$$

$$\sigma_v^{/} = \sigma_v - \alpha P \quad \text{(2.7)}$$

σ_1, σ_2 are the maximum and minimum horizontal stresses respectively and can be calculated as:

$$\sigma_H{}^{/} = \frac{v}{1-v}\sigma_v{}^{/} \quad \text{(2.8)}$$

$$\sigma_H = \frac{v}{1-v}(\sigma_v - \alpha p) + \alpha p \quad \text{(2.9)}$$

$$\sigma_H = \frac{v}{1-v}\sigma_v + \left(\frac{1-2v}{1-v}\alpha P\right) \quad \text{(2.10)}$$

The effective rock stress (stress that produces a deformation in the rock skeleton) can be obtained for Non-Penetrating fluid as follows:

$$\sigma_z = \sigma_V + 2\mu(\sigma_1 - \sigma_2) - \alpha P \quad \text{(2.11)}$$

$$\sigma_\theta = 3\sigma_1 - \sigma_2 - P_{wf} - \alpha P \quad \text{(2.12)}$$

$$\sigma_r = P_{wf} - \alpha P \quad \text{(2.13)}$$

Biot's constant is factor relating the extent of the compressibility of the dry skeletal frame to the rock material, it is defined as:

$$\alpha = 1 - (K_{sk} / K_s) \quad \text{...} \quad (2.14)$$

The Biot's constant can be obtained experimentally, one approach to determine Biot's constant is that presented by Krief et al

$$\alpha = \left[1 - \frac{(1-\phi)^3}{(1-\phi)} \right] \quad \text{...} \quad (2.15)$$

Failure Envelope and Strength Parameters

According to the Mohr Coulomb failure criterion

$$\sigma_1 = \mathrm{C}_0 + \sigma_3 \tan^2 \beta \quad \text{...} \quad (2.16)$$

Where:

$$C_o = \frac{1}{2} UCS \cos\beta \quad ; \qquad \beta = \frac{\pi}{4} + \frac{\theta}{2}$$

The Mohr's Circle Theory, as applied to rock failure assumes that the key stresses are the radial (σ_r) and tangential (σ_θ) stresses, which are in the horizontal plane. The technique assumes that the effect of vertical stress is negligible.

Rock failure occurs when the surrounding stress exceeds the rock strength [tensile, compressive, or shear strengths]. Production of hydrocarbons from geological reservoirs, and injection of fluids into geological strata are accompanied with stress changes in the reservoir and in the cap rock. If the stress changes are large enough, they may reactivate faults or pre-existing natural fractures, or induce new fractures in the reservoir and/or the cap rock. Fractures in the cap rock caused by stress changes during EOR injection may threaten the cap rock integrity. Fractures within the reservoir may increase its injectivity, improve hydraulic communication and thereby facilitate spreading of the injected fluid.

Stress changes during production of oil and gas have been studied in reservoir geomechanics for the past 20 years. Stress dynamics during depletion of an oil reservoir is caused by poroelastic coupling between the pore pressure and the mechanical stresses. Assuming the pore pressure decreases in the entire reservoir, no pore pressure change occurs outside the reservoir (permeability is much smaller in the surrounding rock than in the reservoir), and the stiffness of the reservoir is not much different from the over, under and side burden (Alexandre Lavrov -2016).

One of the key steps in caprock integrity analysis is to predict potential changes in stresses associated with the proposed injection plan, and the effect of these changes on caprock integrity. Maximum safe operating pressure that doesn't compromise the integrity of the caprock depends on several key factors such as rock mechanical properties, rock strength, in-situ stresses and changes in rock properties, and stresses due to steam injection.

If fluid is injected into a deep saline aquifer surrounded by low-permeability rocks, and the reservoir has not been previously depleted, the stress dynamics will be opposite to that under depletion. The stress dynamics during injection into such a reservoir are summarized in Table 2.2, Arrow up designates an increase, the stress becoming more compressive. Arrow down designates a decrease, the stress becoming less compressive again under the assumptions of little elastic contrast between the reservoir and the surrounding rocks, and no pore pressure change outside the reservoir.

Table 2.2 Stress Changes during Depletion (Alexandre Lavrov -2016)

Location	**σv**	**σv/**	**σH σh**	**σH**
Reservoir	↓	↑	↓	↑
Overburden	↓	↓	↑	↑
Side burden	↑	↑	↓	↓

Ensuring caprock integrity is critical to successful thermal recovery processes in oil sands such as steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Continuous steam injection triggers complex coupled thermal and hydraulic processes, which can dramatically change the state of in-situ stresses, reduce rock strength, induce new fractures or re-activate existing fractures posing continued risk of containment breach of caprock.As presented by Safdar Khanet/al (2011), when steam is injected, pore pressure in the reservoir increases, which has several effects on mechanical behavior of rock such as:

1) Increase in pore pressure, which can cause (i) Dilation in the adjacent layers. (ii) Transient increase in overburden stress. (iii) Deficiency in horizontal stresses among many other effects.

2) These effects can lead to micro shear fractures in the adjacent layers, especially at the reservoir boundaries. Increase in formation pressure decreases the effective stresses which can reactive the existing fractures or faults.

3) If effective stress decreases significantly, there is a possibility that it can become zero or negative leading to tensile fractures.

4) At low confining pressures, shear strength of rock reduces significantly making rock susceptible to fail in shear easily.

5) A high-rate injection may lead to inadvertent hydraulic fracturing within the reservoir, with the potential for such fractures to grow upwards into and through the cap rock.

Many authors studied the reservoir and cap-rock integrity during CO2storage (Gennady Yu- 2013, Bahman Bohloli– 2014, Michael Warsitzka - 2017)

Chapter 3

Methodology and Procedures

Introduction

The main objective of a reservoir simulation is to predict field performance and ultimate recovery for various field developments scenarios to evaluate the effects on recovery of different operational conditions and compare economics of different recovery method.

Reservoir Simulation combined with the rock mechanical properties was used to address the effect of temperature distribution inside the rock during CSS process; thermal compositional simulator referred to Computer Modeling Group software (CMG)was selected as the simulation soft wares as it is used around the world and the required geological models for the desired field are available on the sof twares format; The software provides three simulators namely are:IMEX (black oil simulator), GEM (compositional simulator), and STARS(thermal compositional simulator).Types of reservoir simulation models:

1. Black oil.
2. Compositional model.
3. Thermal model.
4. Single porosity or dual porosity (for fractured reservoir).

Generally, there are three kinds of models involved in developing simulation program:

(I) The Mathematical Model, including dynamical system, statical system, differential equations or game theoretical models. This process usually involves assumptions.

(II) The Numerical model which solve the equations constituting a mathematical model, and used with combination of physical modeling to study the mechanism of oil displacement

(III) The Computer model which refers to a computer program or a setoff programs written to solve the equations of the numerical model constitutes a computer model of the reservoir

3.2 Model Grid and Properties:

The Reservoir, simulation allows a more detailed study of the reservoir through dividing the reservoir into a number of blocks and applying fundamental equations for flow through porous media to each block.

Well FNE 17 was selected to implement the analyses as it was produced sand and CSS technique was applied to overlay the production of its heavy oil also water was observed at many work-over reports during the CSS process. Aradeiba and Bentiu reservoir are the target formation to exploit heavy oil from this well. Based on Mud logging, there are two oil zones interpreted in Aradeiba formation, and ten oil zones interpreted in Bentiu formation. Table 3.2 presented the wireline log interpretation result.

The well was completed on May.09.2010 with 7″casing; and 5-1/2″ production casing with targeting formation of Bentiu; the well-produced from Bentiu formation with perforated intervals in zone No.6, 7 and 8 (515.5-536 m) with 45° phasing, Table 3.2 presented the well completion intervals. The well was put into production on Jun, 19.2010, Up to Jun.29 Total produced Oil: 402407STB, Produced water: 86881 STB while the produced sand is 35.5BBL. Useful production data: Pump (40-275TH7.2S-1.2 G-3) Flow line Temperature of. 67oC, Stroke length 3.2m, Freq. = 35Hz, fluid = 111STBD, oil 96, water cut = 14%, Sand cut = 0.0% Pump Submergence: 352. Fluid level: 142.Thermal production (CSS) started at Dec.2010; the number of cycle by 7th May 2018 were reached 6 cycles.

The Geological model consist of variable grid interval has been adopted in the model to accurately describe the structure model. The number of nodes used to perform the analysis is 16×2×40. The average cell sizes in X and Y directions are 126 ft and 174 ft respectively with total grid of 640 Single porosity model Radial coordinate, the average cell thicknesses (DZ) of 10 ft.; the simulation was started in 1st May 2010. PVT data was presented in table (3.3) for the formations under analysis the black oil simulation was started in 4th of May 2010. All the vertical heavy oil wells were completed with 7″production while 5-1/2″ production casing for the wells. Fig (3.1**)** presented a schematic diagram for formation and the layers defined in the reservoir mode.

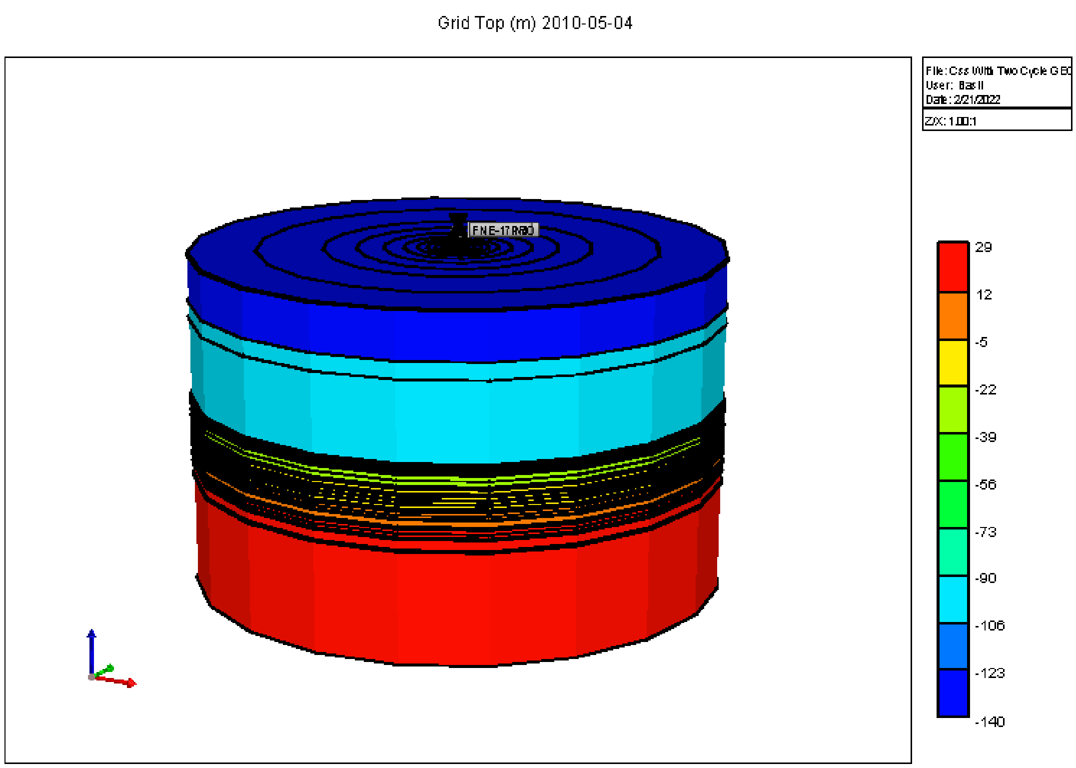


Fig (3.1) FNE 17 Model 3D Grid System Defined in the Reservoir Model

The wireline log interpretation result were presented in Table 3.1 while production intervals presented in Table 3.2 In addition the PVT data was presented in Table (3.3) for the formations under analysis.

Table 3.1 FNE-17 Wireline Log Interpretation Result

Formation	Zone number	Top	Bottom	Thickness	Net pay
Aradiba	4	448.4	451.26	2.9	1
	5	451.3	456.59	5.3	2.13
	6	514.8	517.55	2.7	0.8
	7	518.3	532.03	13.7	8.38
	8	532	536.75	4.7	3.35
	9	536.8	540.72	4	0.4
Bentiu	10	540.7	547.42	6.7	3
	11	547.4	549.4	2	1
	12	551.7	554.58	2.9	2
	13	554.6	561.29	6.7	6
	14	564.8	568	3.2	2.13
	15	568.9	582.93	14	10.4

Table (3.2) FNE-17 Current Production Intervals

Formation	Zone No	Top(m)	Bottom(m)	Thickness (m)
Bentiu	6	515.5	516.3	0.8
	7	519	520	1
	7	523	531	8
	9	533	536	3

The steam injection data presented through Table 3.4 while other control parameters of Bentiu's Formation are as follows:

Minimum Production flowing pressure set to 700kpa, Formation Water Formation volume Factor 1 BBL/STB

Formation water Dencity： 1000 Kg/ m3

Formation water viscosity： 0.617 Cp

Formation water compressibility 0 1/KPa

Initial rock compressibility: 1.9 E-6 1/KPa

Reference Pressure: 6382 Kpa

WOC: 615.8 m.

Table (3.3) FNE-17 PVT Data Used in the Simulation Model

Temp ^oC	oil Viscosity vp
0	38985.41
20	5689.77
25	3724.15
30	2488.59
35	1696.03
40	1177.74
43.7	909.6
50.1	598.57
60	324.5
80	112.99
90.1	71.49
100	47.65
150.3	10.21
200.5	4.03
250	2.31
270	1.98
290	1.74
310	1.56
330	1.43
350	1.34
370	1.26
390	1.2

Table 3.4 Steam Injection Data Used in the Simulation Model

Injection rate (m^3/d)	750, 1000, 1500
Steam volume(m^3)	Qinj* Injections Days
Steam quality	0.8 and 0. 85
Steam temperature(C)	255
Injection pressure(Mpa)	200

3.3 Geo-mechanics Calculations:

Pressure and temperature variation due to cyclic steam stimulation play an important role in increasing recovery from reservoir and affect in the stress behavior in reservoir. Therefore, taking the geo-mechanics under consideration is important to understand the reservoir behavior. The main parameters to be considered are Poisson's ratio (μ) and Young’s elastic modulus (E). As no static data are available, dynamic data, using dipole sonic and density log were used to calculate the required parameters. However, the available sonic missing the shear velocity; therefore, two alternatives methods were used to estimate the properties using compressional sonic and density log .

[1] In the first methods, Anderson model (1973) used to calculate Poisson's ratio as follows:

(I) Sonic porosity was calculated using equation 3.1 with fluid acoustic value of 189 μs/ft. and matrix acoustic value of 54.8 μs/ft

$$\phi_s = \frac{\mathrm{DT}-\mathrm{DT}_{ma}}{\mathrm{DT}_f-\mathrm{DT}_{ma}} \quad \ldots\ldots (3.1)$$

(II) Density porosity was calculated using equation 3.2 with matrix density of 2.65 g/cm3 while the filtrate mud density is 1 g/cm3

$$\phi_D = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f} \quad \ldots\ldots (3.2)$$

(III) The shale index (q) was calculated using the following equation:

$$q = \frac{\phi_s-\phi_D}{\phi_s} \quad \ldots\ldots (3.3)$$

Poison’s ratio was calculated using the following equation

$$\mu = 0.125q + 0.27 \quad \ldots\ldots (3.4)$$

For homogeneous isotropic and elastic rock, physical rock, Shear Modulus is given as:

$$G(psi) = 1.34 * 10^{10}\frac{\rho_B}{{\Delta t_s}^2} \rightarrow G = 1.34 * 10^{10}\frac{A\rho_B}{{\Delta t_s}^2} \quad \ldots\ldots (3.5)$$

For homogeneous isotropic and elastic rock, physical rock, Young’s Modulus is given as:

$$E(Psi) = 1.34 * 10^{10}\left(\frac{\rho_B {V_s}^2(3{V_c}^2 - 4{V_s}^2)}{{V_c}^2 - {V_s}^2}\right) \quad \rightarrow \quad E = 2G(1+\mu) \text{ .... } (3.6)$$

For homogeneous isotropic and elastic rock, physical rock, Bulks Modulus: is given as:

$$K_B(Psi) = \frac{1}{C_b} = 1.348 * 10^{10}\rho_B\left(\frac{1}{{\Delta t_c}^2} - \frac{4}{3{\Delta t_s}^2}\right)$$

Or $$K_B = \frac{1}{C_b} = 1.34 * 10^{10}\frac{B\rho_B}{{\Delta t_c}^2} \text{ .... } (3.7)$$

$$K_B = \frac{E}{3(1-2\mu)} \text{ .... } (3.8)$$

Table 3.5 Mechanical properties using Anderson's Equation Brocher's Equation

Parameter	Anderson's Equation
Poisson's ratio (μ)	0.314158048
Shear modulus ((Kpa)	$2.9E^{+06}$
Young's modulus (E)(Kpa)	$7.5E^{+06}$

Data from these sources are integrated with coupled reservoir-geo-mechanics modeling to estimate induced stresses and changes in rock strength due to steam injection. These changes will be ultimately used to assess failure in the cap-rock.

Coupled reservoir-geo-mechanics modeling is conducted to quantify the changes in in-situ stresses caused by steam injection. For each injection scenario, changes in temperature (T) and changes in pressure (p) are computed in the reservoir simulation model. The corresponding changes in stresses and strains porosity, and permeability (k) are computed based in the calculated geo-mechanics

3.4 History Matching:

As histories match allowing making accurate predictions and evaluating alternative production scenarios; history matching was carried out manually with the estimated mechanical properties of two previously presented models; the history match plots of oil and water production were presented through Fig .3.1 and Fig .3.2

Standard procedures were used to achieve a technically acceptable match. Some adjustments including cell permeability, the shape of the relative permeability curves were done to reflect the actually individual well behavior. In addition, adjustments were made to the productivity index of some wells to achieve the actual oil and liquid production rate. The wells has gotten a good match, starting from 2014 so the next accurate plan prediction can be designed using the current this history match. The history match plots of oil production rate and water rate are shown through Fig. (3.3) and Fig (3.4) respectively.

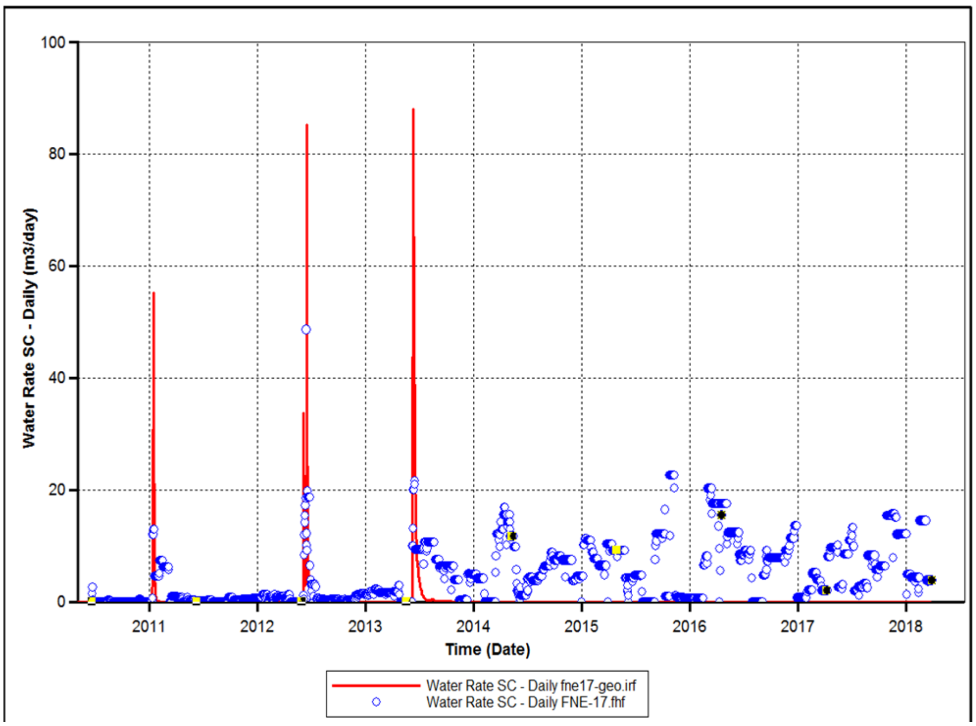


Fig 3.2 Water Production History Match plots using Geo-mechanics

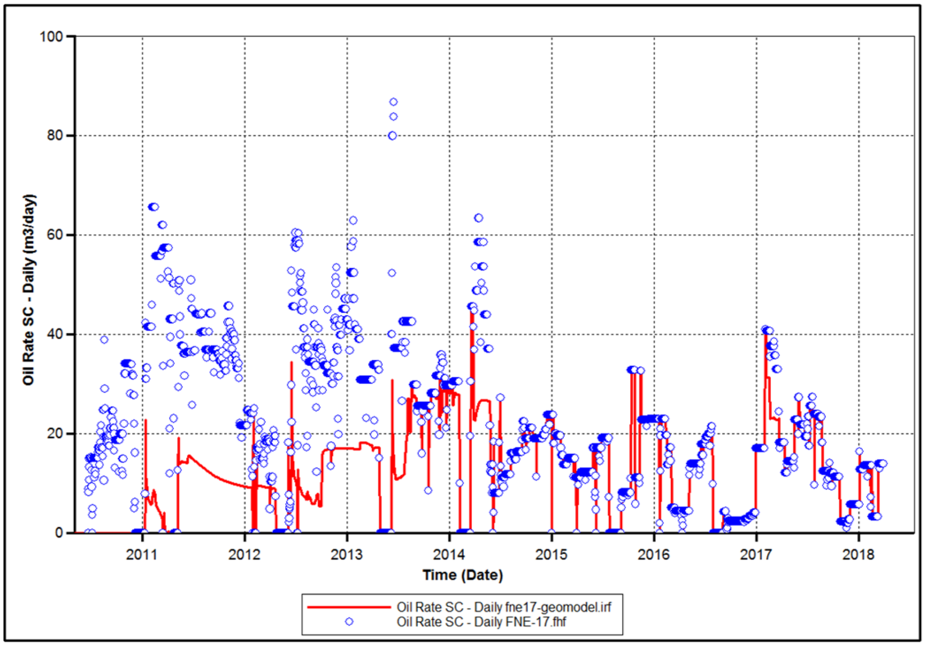


Fig 3.3 Oil Production History Match plots

After a good history match was achieved; the simulation was run to predict the performance of the wells for 4 years with 7 cycles; and the effective of the geo-mechanics in the porosity and cap rock failure was studied under different different injection rate and different steam quality. Fig(3.5) shows the 2D grid system for the model; while Fig (3.6) presents the Temperature distribution for the well before CSS at the begging of the simulation.

Chapter 4

Results and Discussion

Historically, considering geo-mechanics and deformation the pore volume and Bulk volume will change; when injecting fluid in the formation the normal effective stress is decreasing which may induced fracture in the formation while the pressure rises; while during production the normal effective stress increases however the fracture will not closed. Fractures in the cap rock caused by stress changes during CSS may threaten the cap rock integrity. While fractures reservoir may increase its injectivity, and communication and thereby facilitate spreading of the injected fluid.

Using the pre described reservoir rock and fluids properties, many Scenarios conducted to study the effect of steam parameters and injection schedule on oil production and water production and cap rock interiority.

The injection rate and steam quality were optimized depending on oil and water production and cap rock interiority; when any increases of those parameters is followed by considerable failure the increment is then unfavorable.

To consider the effect of the above-mentioned parameters in the cap rock the cap rock properties presented by Gutierrez (2001) assumed as follows:

1. Young's modulus, E (GPa) 2.5
2. Poisson's ratio, 0.45
3. Absolute permeability, k (md) 0

First, the simulator was run neglecting Geo-Mechanics to predict the well performance; then considering geo-mechanics in reservoir water saturation were calculated and compared with that without considering geo-mechanics to insure the effect of deformation. Fig 4.1 and Fig 4.2 presented the water saturation for the two cases and it is clear that the saturation is affect by the deformation, which were not considered in many studies.

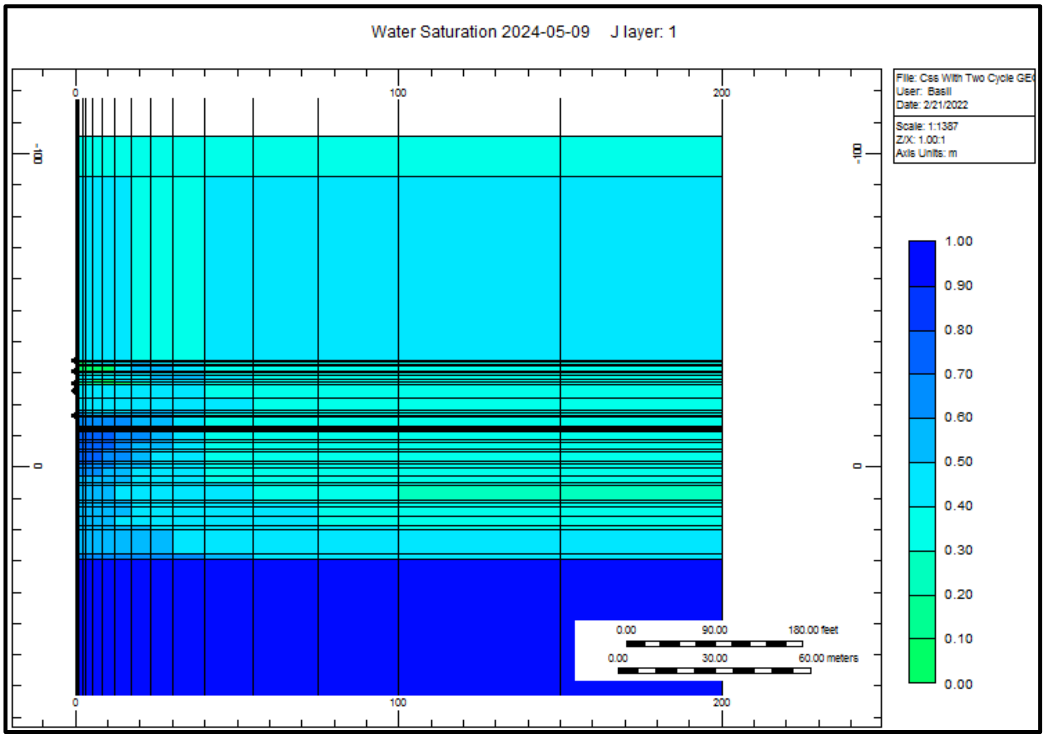


Fig 4.1 Water Saturation in Reservoir Neglecting Geo-Mechanics

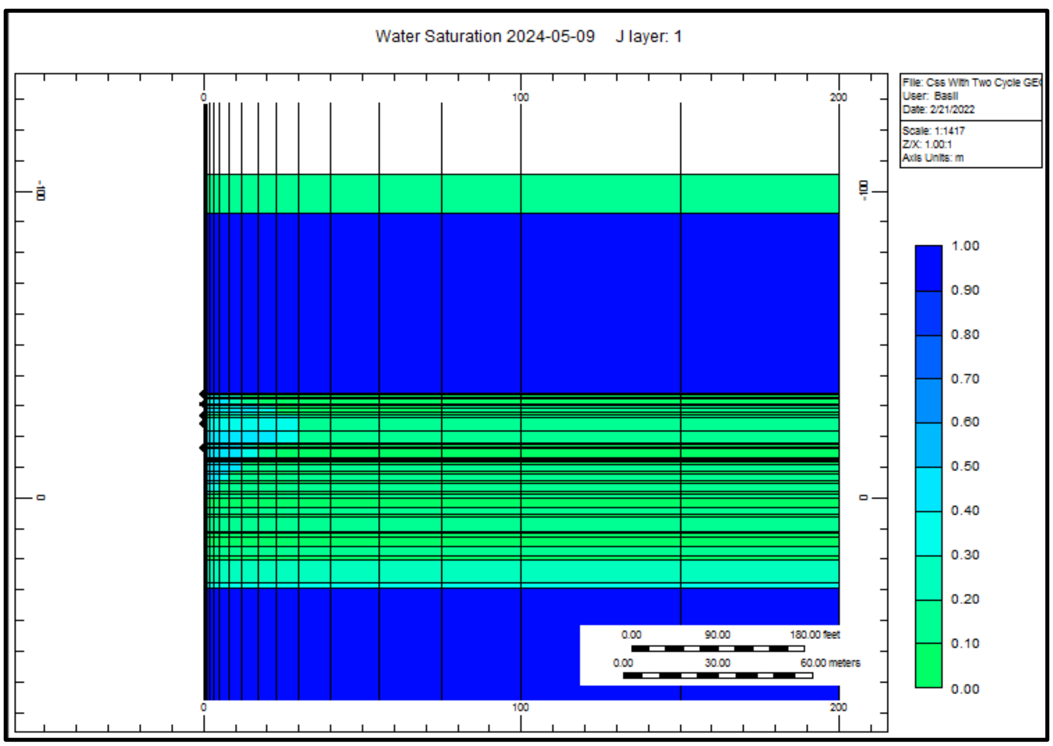


Fig 4.2 Water Saturation Sample in Reservoir Water Considering Geo-Mechanics

Six scenarios were conducted to study the effect of injection rate of 500, 750 and, 1000 m^3/day under constant steam volume of 144 m^3, and steam temperature of 255^oC with steam quality of 0.8 and 0.85. Elasto plastic Mohr–Coulomb was selected as the rock type model as it is the simplest and widely used model; and the shear stress was assumed to be zero as the normal stress was only considered.

Reservoir temperatures will propagate into the overburden rocks via both conduction and convection. The conduction dominates when the rock is intact and no convection occurs. The convection becomes important when the rock fails allowing the movement of the hot reservoir fluid into the overburden. The model dose not account for the convection and it may be considered in other studies.

The yield state was used as an indicator for fracture initiation as used in CMG. Yield State of less than one is indicator for no fracturing or failure occur while Yield State of more than one indicates failure in the rock. Table 4.1 presented the other geo-mechanics rock type parameters used in the model as calculated from the equation presented in chapter 2 and 3.

Table 4.1 Some Geo-Mechanics Rock Type Parameters used in the Model

Parameters	Value
Cohesion	290
Vertical Stress (σv)	3100
Minimum Horizontal Stresses (σh)	2800
Maximum Horizontal Stresses (σH)	4800
Biot’s Constant (obtained by Krief et. al)	0.5355
Friction Angle	30

During simulation the geo-mechanics equations calculates properties such as stress and strain; in the other hand flow equations calculate some parameters such as pressure and temperature; during simulation geo-mechanics need to obtain pressure and temperature from flow equations and recalculate the porosity using the following Equations:

$$\varphi^*_{n+1} = \varphi^*_n + c_0(p_{n+1} - p_n) + c_1(T_{n+1} - T_n) + c_2\Delta\sigma_m \quad \text{……………….(4.1)}$$

By the same way the reservoirs equation some time need to have some properties from geo-mechanics; this communication between the modeling equations known as coupling which can be fully coupling or iterative coupling. The fully coupling approach uses matrix to solve the full equations in some complicated manner; while iterative coupling as it is quicker and simple to use.

The coupling can be one direction though which, a communication between reservoir simulation and geo-mechanics occur but no communication between geo-mechanics and reservoir simulation; therefore, geo-mechanics obtains pressure and temperature from reservoir simulation but reservoir simulation do not obtains porosity from geo-mechanics. The two-direction coupling in which communication between reservoir simulation and geo-mechanics and between geo-mechanics and reservoir simulation occur.

Through this research, two-direction coupling considered, and the effect of deformation and two-direction coupling can be observed from the porosity distribution for each injection rate as presented through figures 4.3 to 4.5.

It is clear that considering geo-mechanics and two-direction coupling calculates the accurate porosity which affected by deformation result from injection.

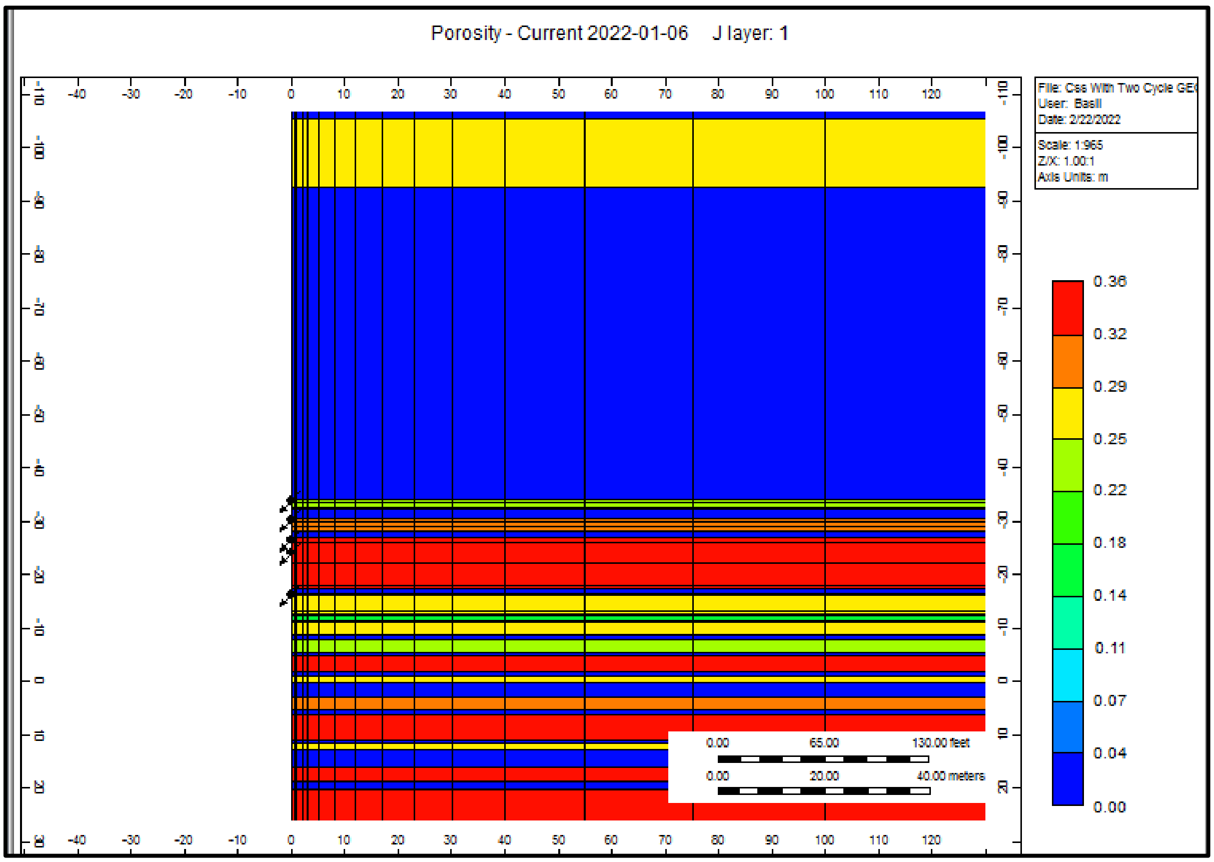


Fig 4. 3. Porosity Distribution (500 m^3/day during Production Neglecting Geo-Mechanics)

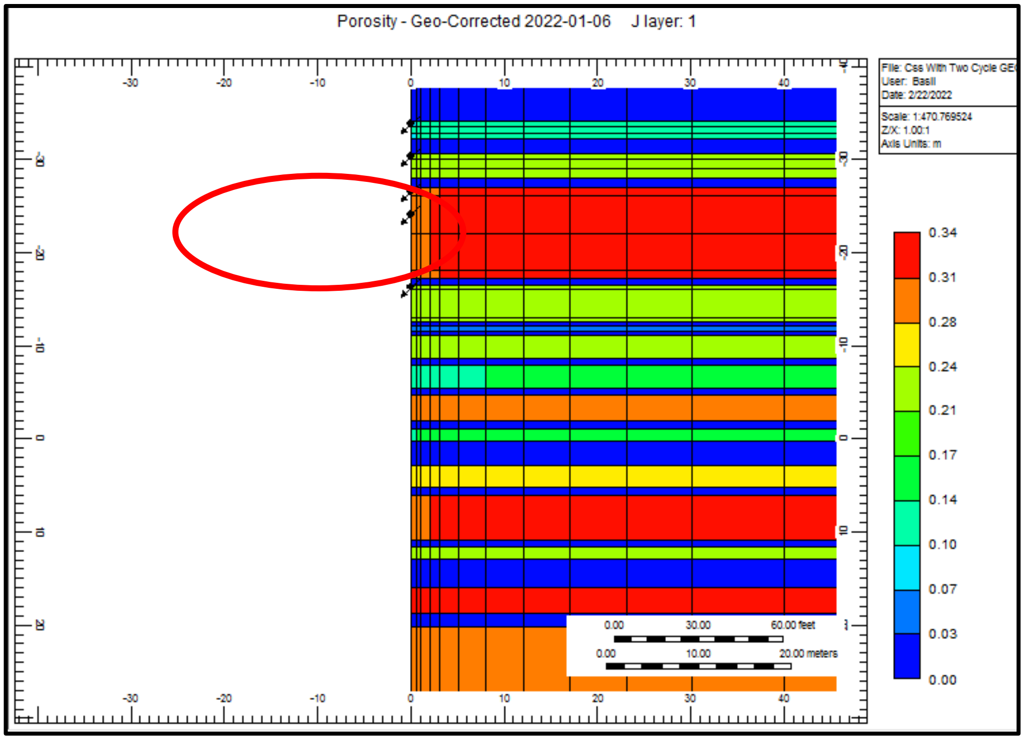


Fig 4. 4 Porosity Distribution (500 m^3/day during Injection Considering Geo-Mechanics)

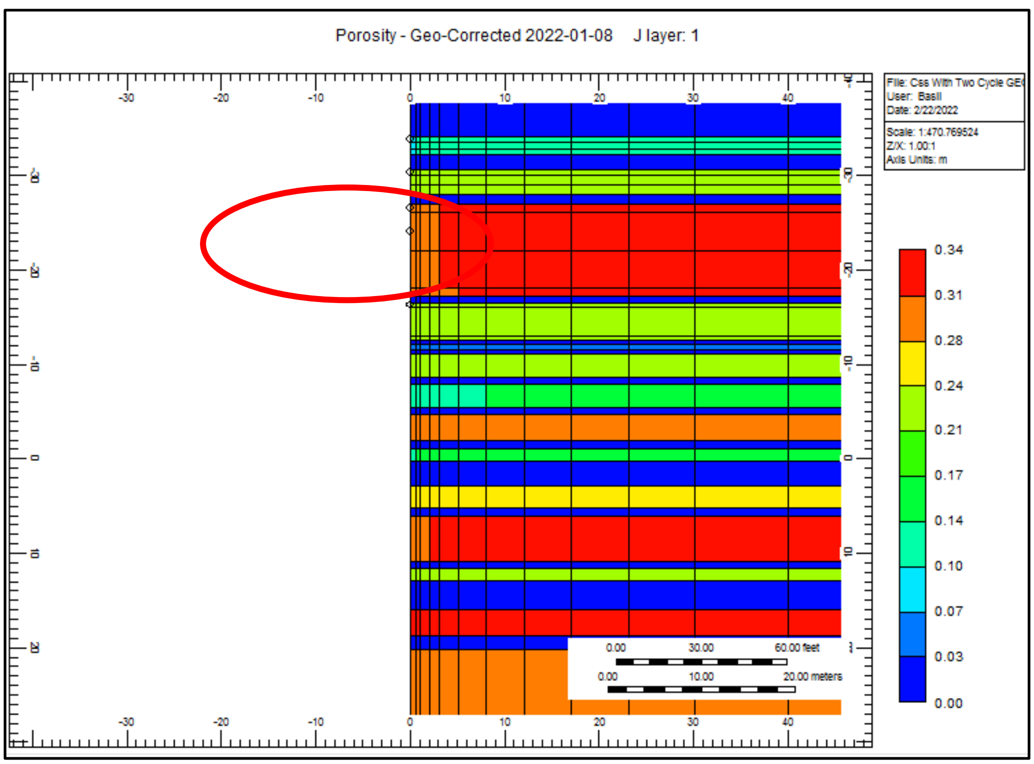
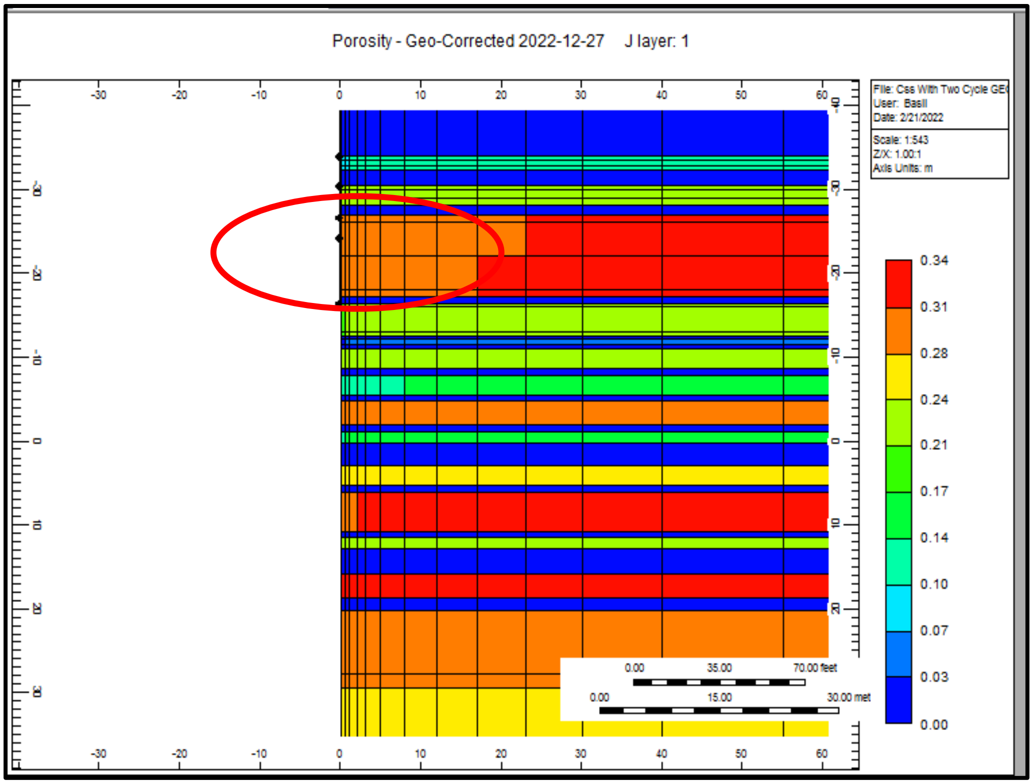


Fig 4.5 Porosity Distribution (500 m^3/day during Soaking Considering Geo-Mechanics



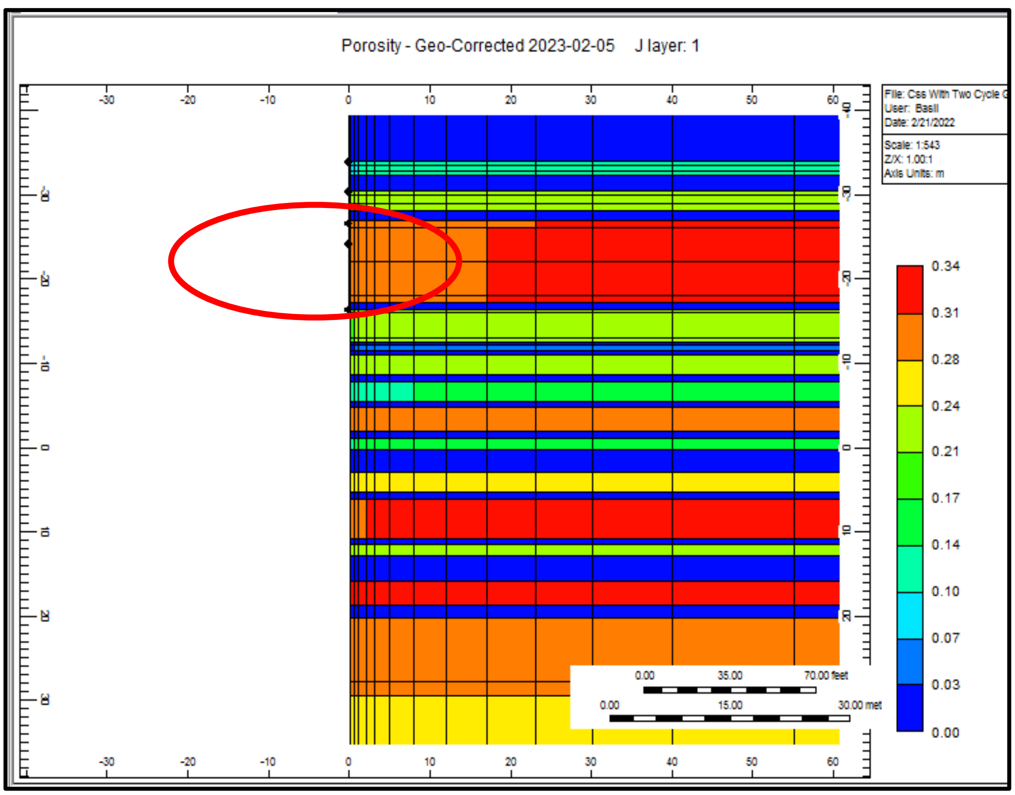


Fig 4. 6 Porosity Distribution (500 m^3/day during Production Considering Geo-Mechanics)

The first Scenarios consist of 500 m3/day for 12 injection days. Figure Fig 4.7 to 4.9 shows some examples temperature and stress distributions in the reservoir at different operation days respectively. It should be noted that temperatures and pore pressures in the overburden are calculated based on thermal conduction and pore fluid diffusion through the coupled analysis.

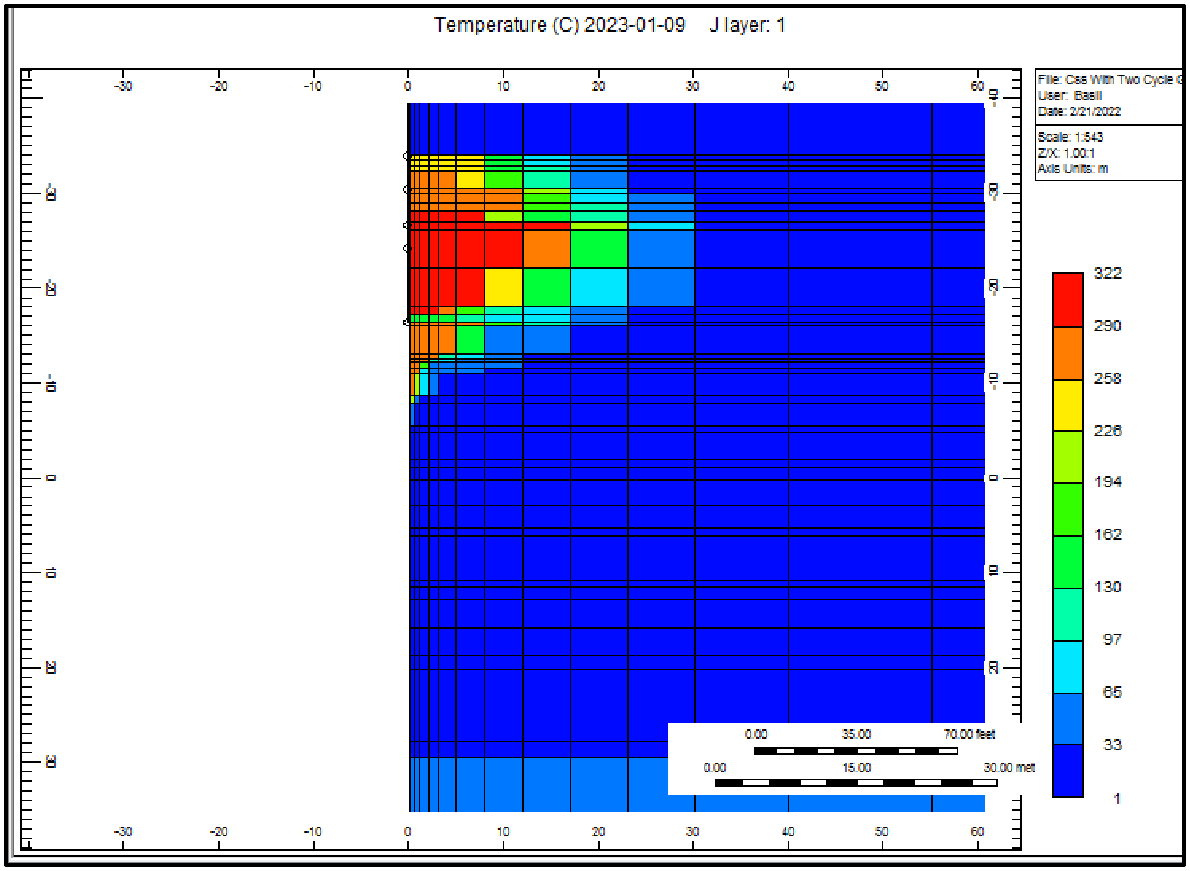


Fig 4.7 Temperature Distribution and by the End of Injection Period for 500 m^3/day

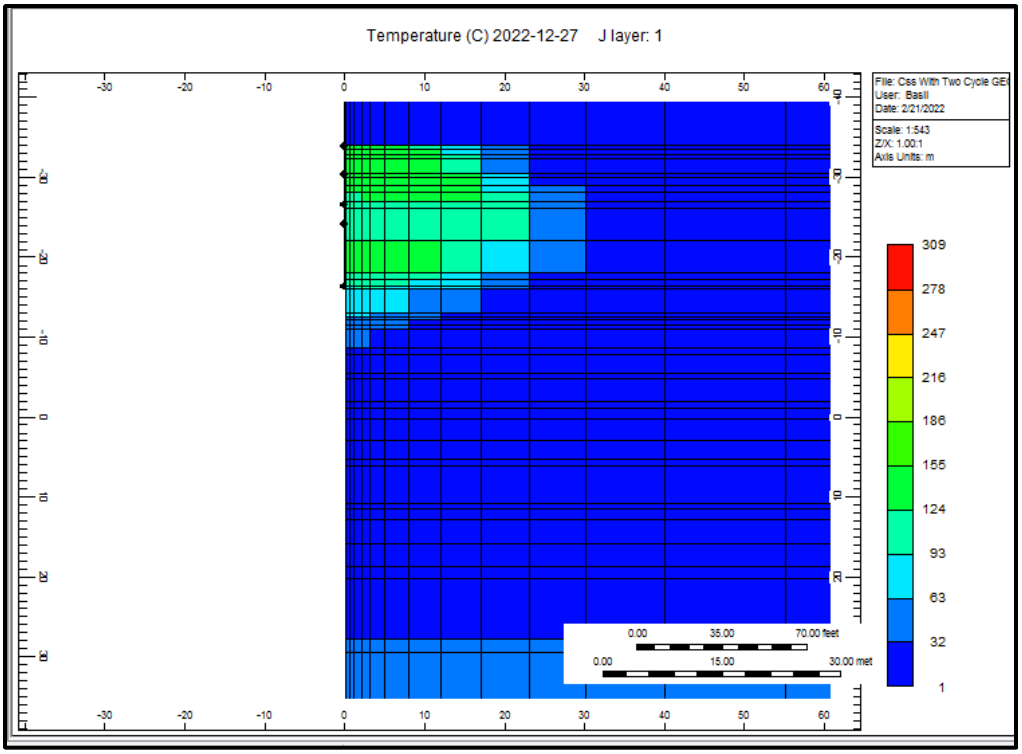


Fig 4. 8 Temperature Distribution and by the End of Production Period for 500 m^3/day

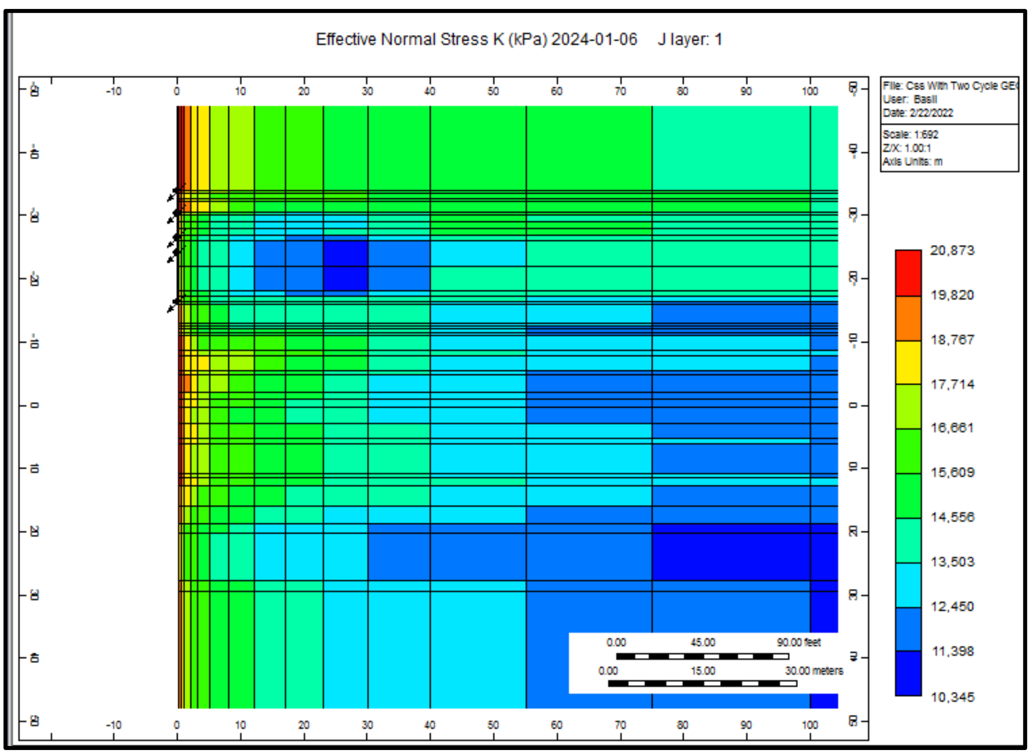


Fig 4. 9 Stress Distribution during Injection Period for 500 m^3/day

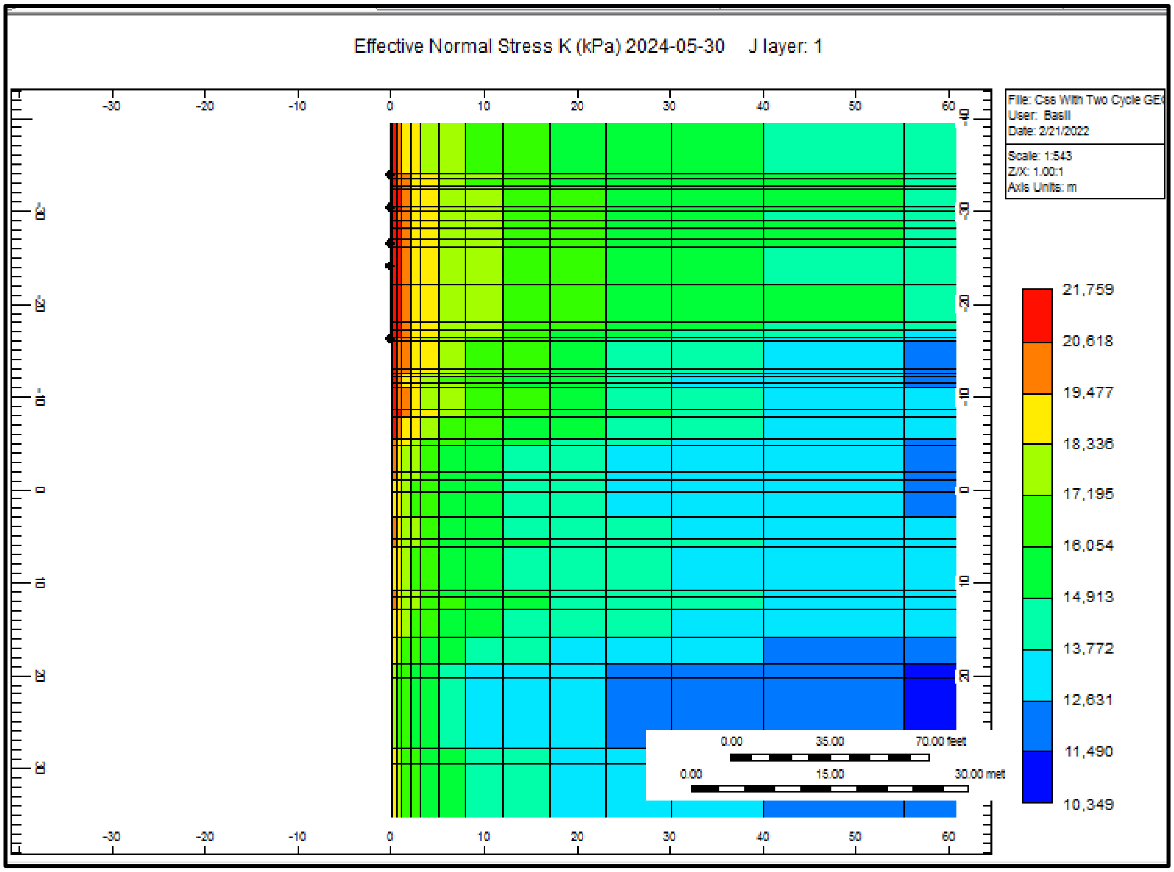


Fig 4. 10 Stress Distribution during Production Period for 500 m^3/day

4.1 Sensitivity Analysis:

An extensive study were then performed to over come the effect of the injection on the stress distribution in the reservoir during injection and production periods. As presented previously the normal stress reduces with injection and increasing with production in an opposite way for pressure, which may case failure. Fig 4.11 to 4.13 presented some examples stress distributions in the reservoir at different operation days for injection rates varying from 750, 1000, and 1500 m^3/day respectively.

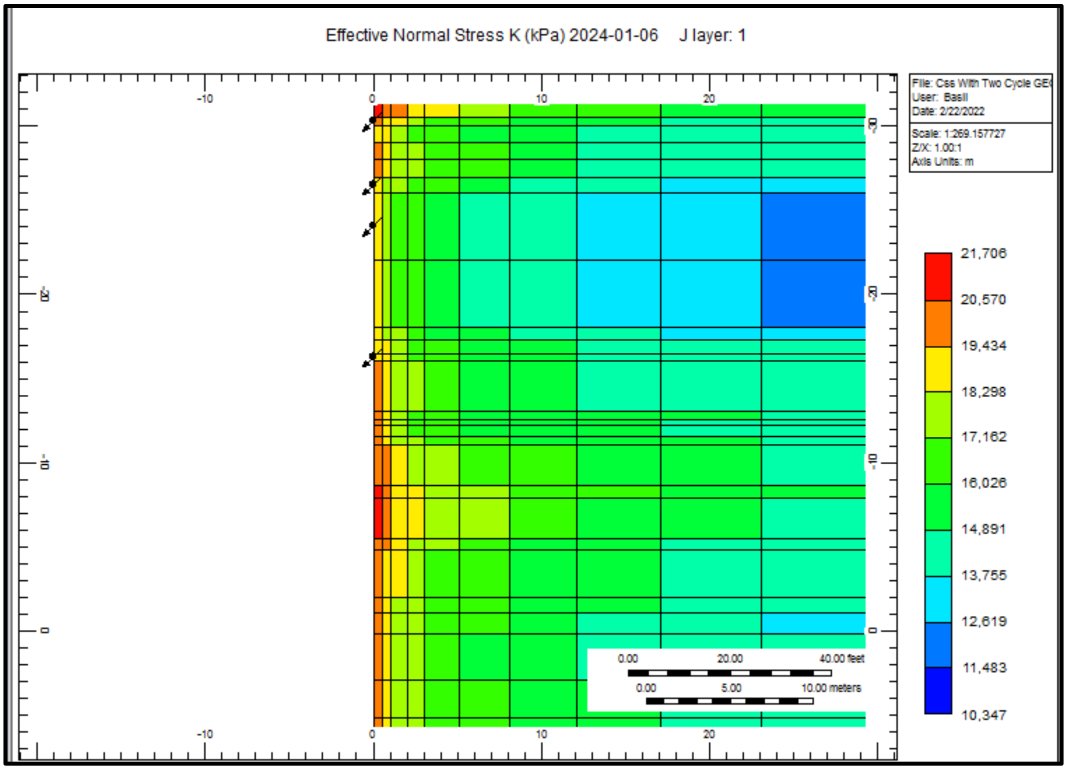


Fig 4. 11 Stress Distribution during Injection Period for 750 m^3/day

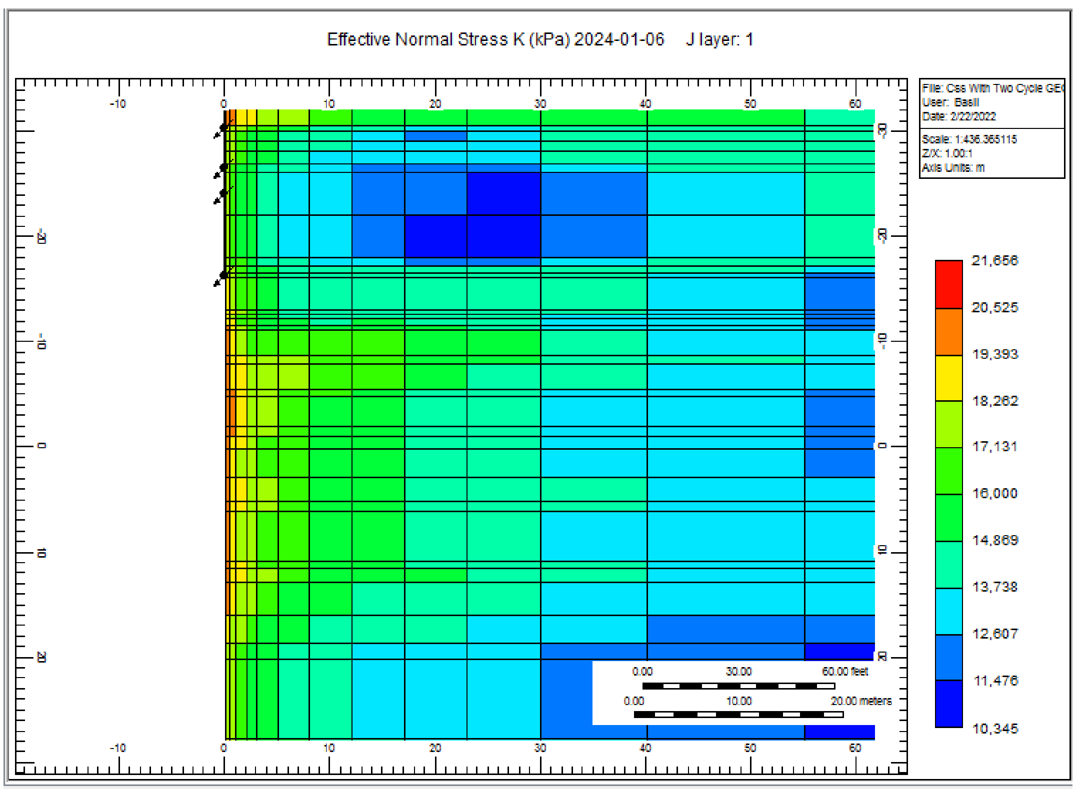


Fig 4. 12 Stress Distribution during Injection Period for 1000 m^3/day

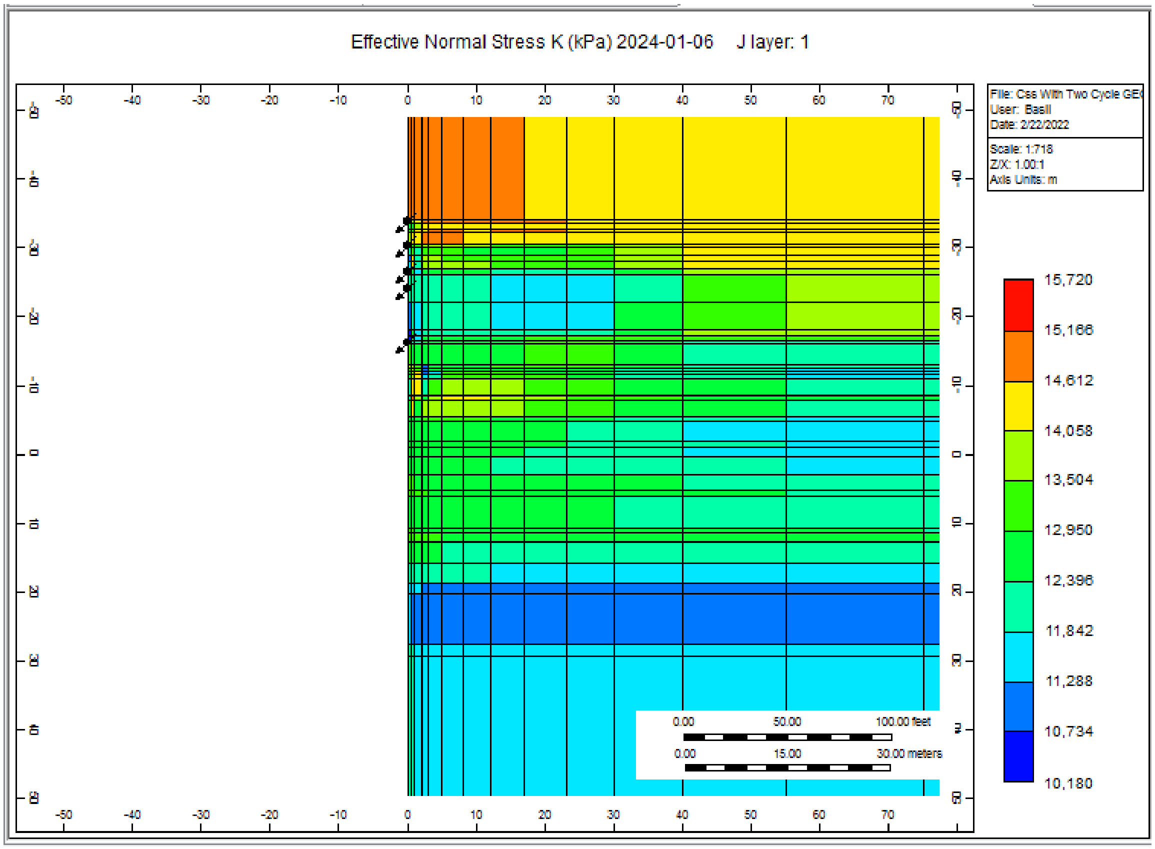


Fig 4. 13 Stress Distribution during Injection Period for 1500 m^3/day

From the figures, it is observed that when the injection rates is 750 m^3/day the normal stress varying between 14,800 to 20,500 KPa. When increasing the injection rates to 1000 m^3/day the normal stress varying between 13,700 to 18,200 KPa; while for injection rates is 1500 m^3/day the normal stress varying between 11.800 - 13.55 KPa; this small normal stress may indicates failure in reservoir

4.2 Cap-rock Deformation

The driving forces for the caprock deformation are the temperatures and pore pressures inside the reservoir during the operations. Geo-mechanical rock properties are derived from sonic logs and Anderson et al. (1973) rock mechanical property correlations as presented through chapter 2 and 3.

Caprock-integrity analysis compares the prevailing stress conditions against the material strength when stress changes in the reservoir and potential flow pathways developed. The yield state was used as an indicator for fracture initiation as used in CMG. Yield State of less than one is indicator for no fracturing or failure occur while Yield State of more than one indicates failure in the rock.

Fig 4.14 to 4.16 presented some examples Yield State distributions in the reservoir at different operation days for injection rates varying from 750, 1000, and 1500 m^3/day and all the other working parameters are constant.

It was observed that when the injection rate is 750 m^3/day (Fig 4.14 and 4.15) the Yield State was 0.0 during the operation days in the early days of CSS; which indicates no fractured was performed in the formations. However, by 27/12/2025 the reservoir and lower zoon fractured for the first time as Yield State reached 1.0; while no any failure indicator was found in the cap rock until the end of the cycles.

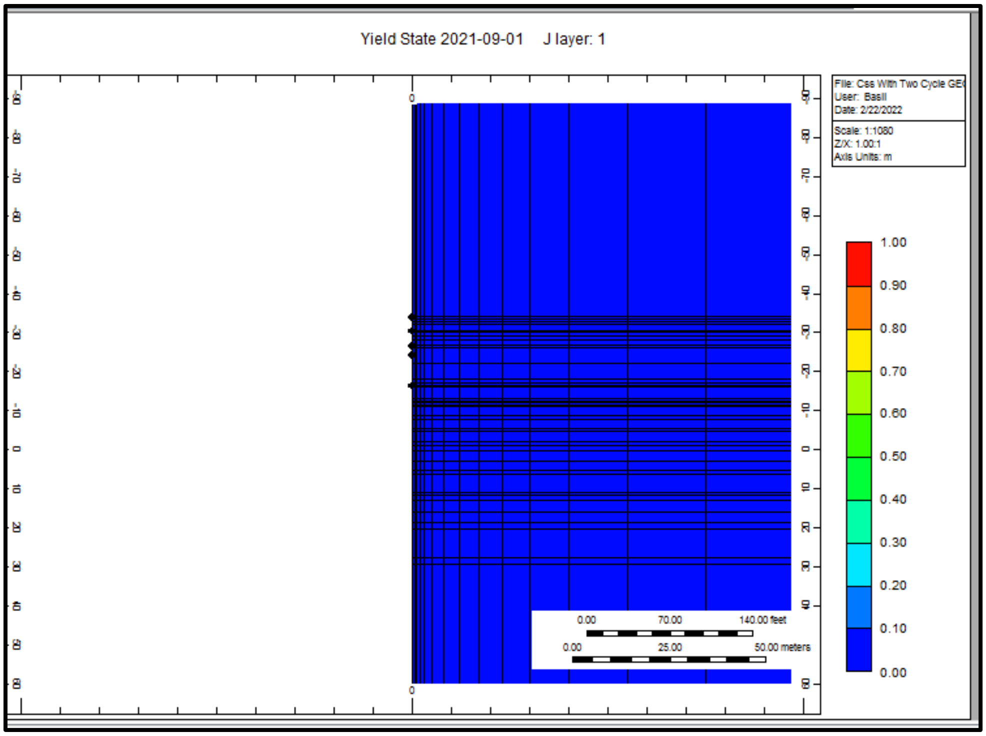


Fig 4. 14 Yield State for 750 m^3/day Early days

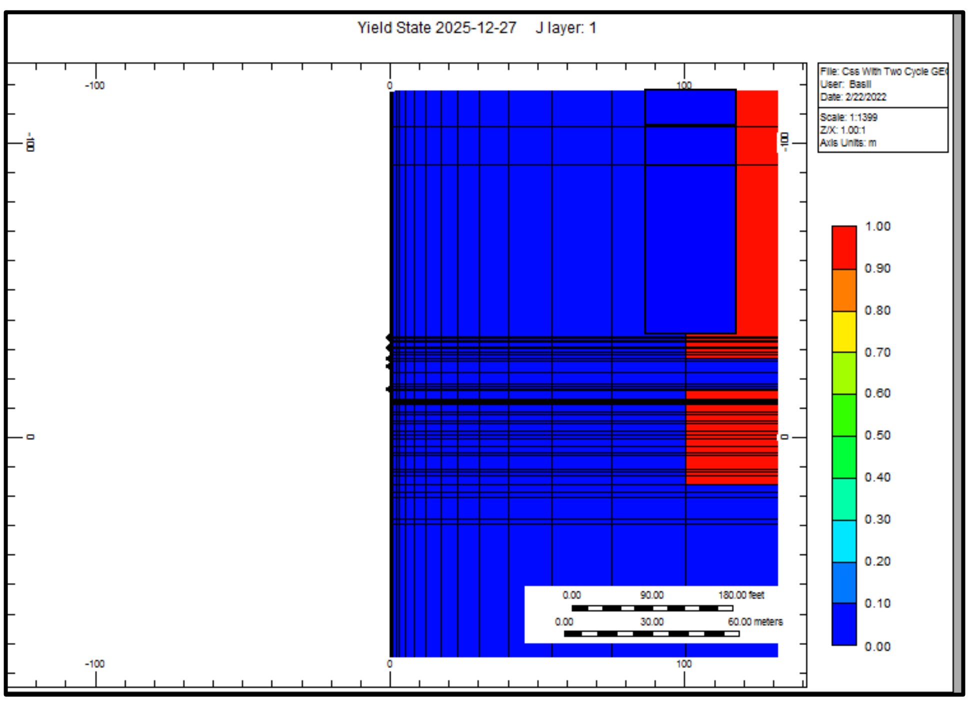


Fig 4. 15 Yield State for 750 m^3/day Lately

For injection rate of 1000 m^3/day (Fig 4.14 to 4.16) the Yield State was 0.0 during the operation days; which indicates no fractured was performed in the formations. However, by 17/9/2021 the reservoir and lower zoon fractured for the first time as Yield State reached 1.0; while no failure indicator was found in the cap rock until 10/2/2025 when the cap-rock was fractured and the Yield State reached value of 1.0 in the cap-rock.

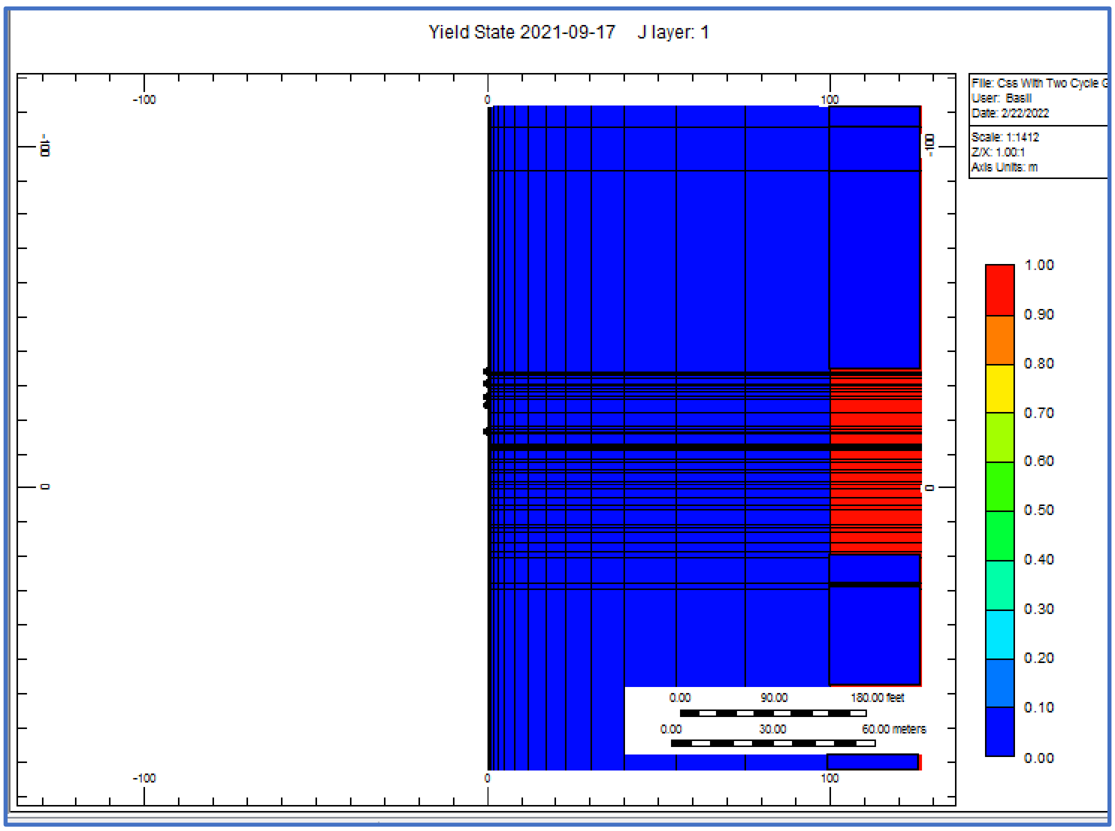


Fig 4. 16 Yield State for 1000 m^3/day Lately

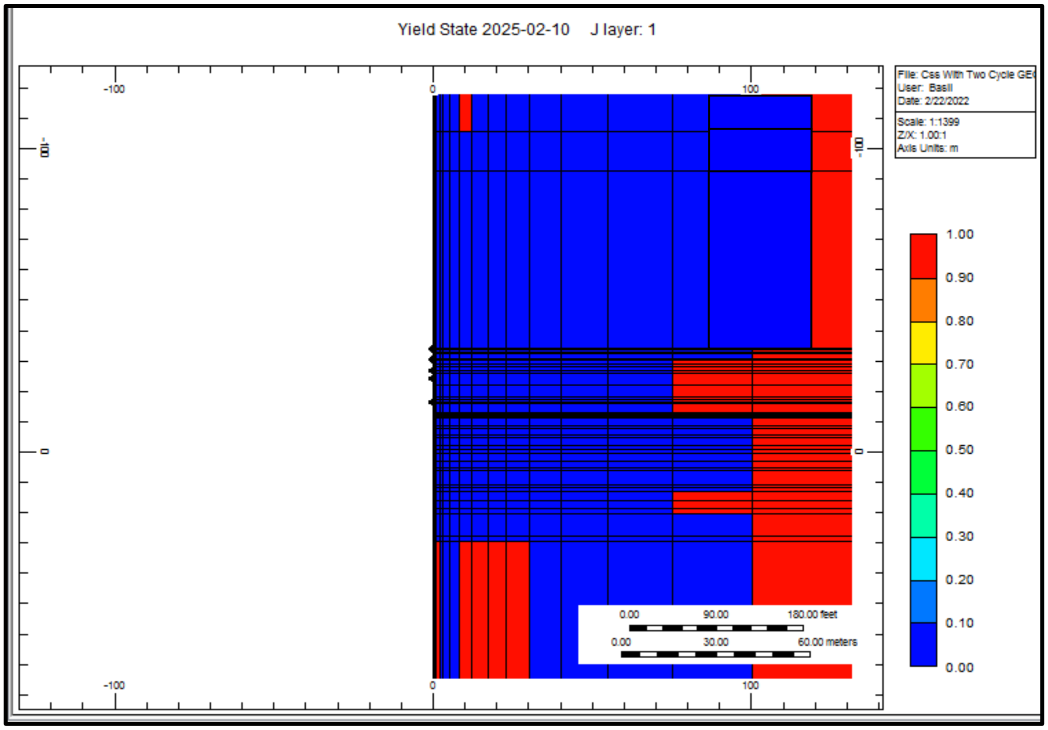


Fig 4. 17 Yield State for 1000 m^3/day Lately

For injection rate of 1500 m^3/day (Fig 4.14 to 4.16) the Yield State was 0.0 during the operation days; which indicates no fractured was performed in the formations. However, by 15/2/2021 the reservoir and lower zoon and caprock were fractured for as Yield State reached 1.0.

From the above analysis, an injection rate of 750 m^3/day can insure cap rock integrity while 1000 and 1500 m^3/day will perform fracture in the caprock at different operations days; also, the time that the fracture can be initiated in early when compared to that of 1000 m^3/day

Ultimately, caprock integrity considers hydraulic integrity—no reservoir fluids should escape through the caprock into the groundwater aquifers or to the surface. In general, the hydraulic integrity is already maintained naturally, as in the geological history of the caprock preventing further upward hydrocarbon migration. During thermal operations, mechanical deformation and potential failure of the caprock may introduce new hydraulic conduits and thus compromise the hydraulic integrity. Therefore, hydraulic integrity becomes a mechanical integrity issue where the formations are relatively shallow. For example, surface heave, which is rock deformation reflected on the ground, can alter the environment by changing the landscape or the surface or shallow subsurface hydrogeological conditions. Such surface heave could damage surface installations and infrastructures, and have other unintended impacts. Furthermore, rock deformation and can damage the well casing, breaking its hydraulic-sealing capacity.

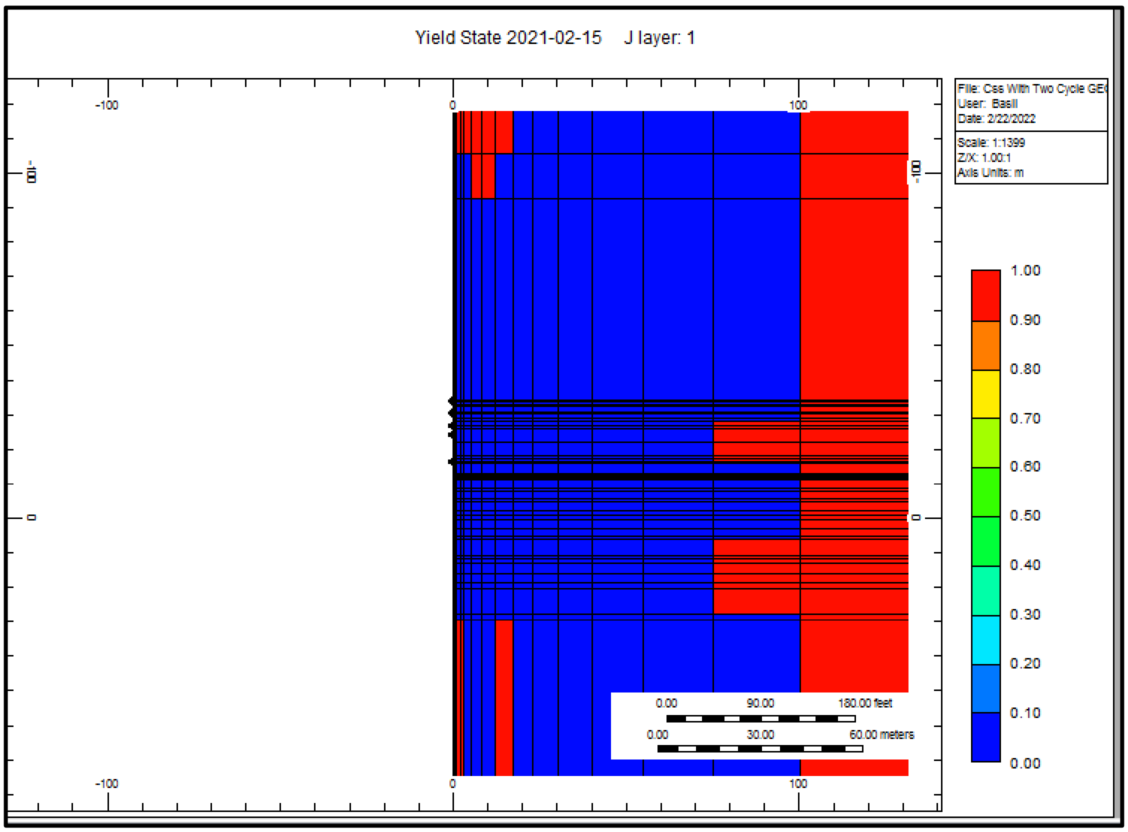


Fig 4. 18 Yield State for 1500 m^3/day

The water production rate was also mentioned to compare the produced water due to the aquifer failure as presented through Fig 4.17 presented from the figures High water cut was observed.

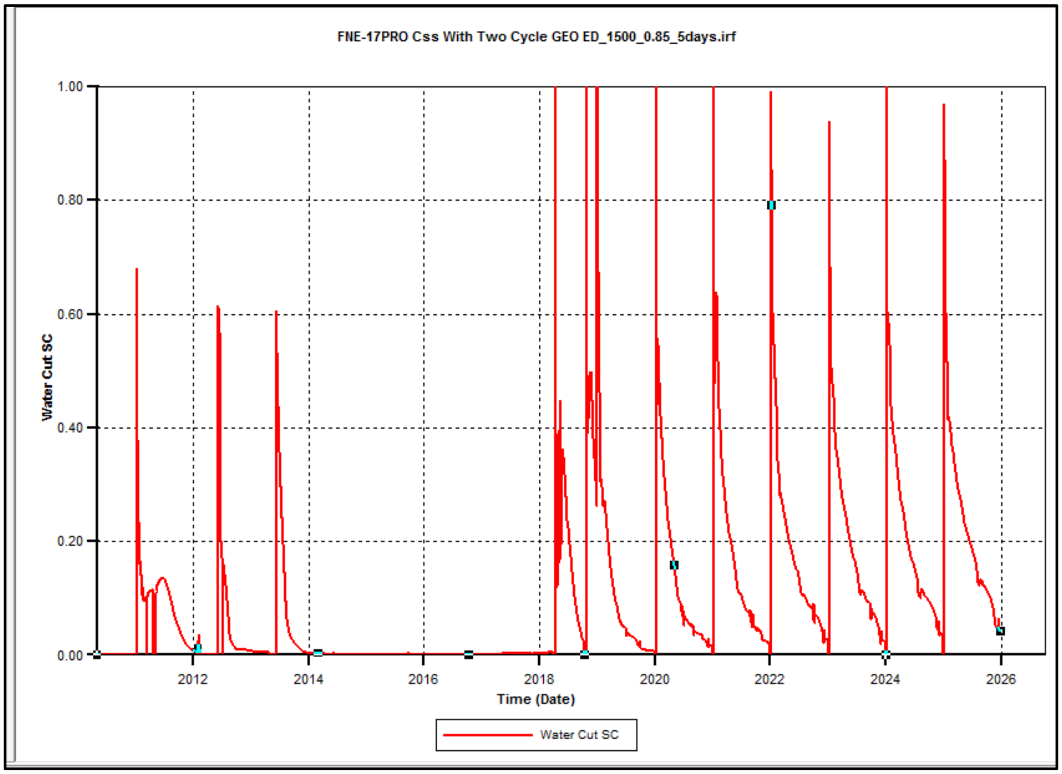


Fig 4. 19 Daily Water Production for 1500 m^3/day

Chapter 5

Conclusion and Recommendations

5.1 Conclusion:

Based on this work and the previous analysis the following conclusions are made:

1. Geo-mechanical concepts with iterative two-direction coupling for reservoir rock and fluids properties, presented the deformation from the normal effective stress which decreases with the of injection rate.
2. An injection rate of $750\, m^3/day$ can insure cap rock integrity while 1000 and 1500 m3/day will perform fracture in the caprock at different operations days; also, the time that the fracture can be initiated in early when compared to that of 1000 m3/day.
3. Water production increases with the injection rate as the aquifer will fractured at early time when the he injection rate is high.

5.2 Recommendations:

1) Some probable mechanisms that are not investigated in the current work program should be considered in the future

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