DEVELOPMENT OF A GAS CONDENSATE RESERVOIR: CASE STUDY OF THE NIGER DELTA

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CASE STUDY OF THE NIGER DELTA

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ABSTRACT

Gas condensate reservoirs are single phase at the initial condition. It changes to multiphase when the reservoir conditions are located between the critical point and the cricondentherm of the reservoir in the phase envelope. This makes it unique to providing a reliable source of energy for human usage.

The objective of this study is to use a 3D compositional model of the Niger Delta field to evaluate the production of a gas condensate reservoir.

This study is integrated into two main segments; the reservoir and fluid pressure, volume and temperature (PVT) model followed by reservoir simulation studies. The simulation involves running several development scenarios using the 3D compositional model of the Niger Delta field to optimize the recovery from the reservoir of interest.

Two vertical and horizontal wells were drilled in the model to study the production of the gas condensate reservoir using two development methods; natural depletion and gas cycling to maintain the reservoir pressure. Production of the gas condensate reservoir by maintaining a higher reservoir pressure through gas cycling maximized the hydrocarbon recovery.
Economic analyses carried out on the net present value (NPV) of the various production methods studied in this work, revealed that gas cycling with vertical wells proved to be economical as a result of higher cash flow and the effect of injection cost on the project profitability.−

The results of this study gave further insights into the need to conduct detailed fluid PVT characterization and the importance of evaluating various reservoir optimization techniques in order to maximize recovery of oil from gas condensate reservoirs.

Keywords: Gas condensate, reservoir modeling, reservoir development methods, NPV analysis, compositional fluid characterization

DEDICATION

I dedicate this thesis to my lovely mother Ernestina Sapong, my grandmother Hannah Mintah Sapong, my sister Lorinda Abeka and not forgetting Emmanuel Nana Danso Obeng.

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My first and foremost thanks go to God Almighty whose unmerited favor guided me during my stay at the African University Science Technology Campus.

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LIST OF ABBREVIATIONS

Bottom-hole flowing pressure	(BHFP)
Capital expenditure	(CAPEX)
Constant volume depletion	(CVD)
Critical condensate saturation	(Scc)
Constant composition expansion	(CCE)
Enhanced Gas Reservoir	(EGR)
Gas Oil Ratio	(GOR)
Net Present Value	(NPV)
Operational expenditure	**(OPEX)**
Peng-Robinson	(PR)
Soave-Redlich and Kwong	(SRK)

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CHAPTER 1

INTRODUCTION

1.1 Problem Definition

The global demand for fossil energy is increasing immensely because of high population and development. With the unbundling of the power sector in Nigeria, and the fact that the country currently suffers from energy poverty complicated by low oil price or oil price volatility, oil companies are looking for ways to minimize costs and increase productivity.

Nigeria has an estimated 180 trillion standard cubic feet of natural gas proven reserves, making it ninth in the world, and the largest in Africa (World Factbook, 2014) with about a 50/50 distribution ratio between Non-Associated Gas (NAG) and Associated Gas (AG). The Natural gas available in Nigeria could either be associated or non-associated. Associated gas refers to the natural gas found in association with oil within a reservoir, while reservoirs that contain only natural gas and no oil, have gas termed as non-associated gas.

Gas-condensate reservoirs represent a vital source of hydrocarbon reserves which have been recognized as a reservoir type, possessing the most complex flow and thermodynamic behaviors. Gas-condensate reservoirs are distinguished by producing both gas and condensate liquid at the surface. Retrograde condensate reservoirs produce gas to liquid ratios of about 3-150 MCF/STB (McCain, 1990), or condensate surface yields which range from 7 to 333 STB/MMCF. The condensate produced adds economic value in addition to gas produced, therefore making the condensate recovery a key consideration in the development of gas-condensate reservoirs. At greater depths during exploration, gas condensate reservoirs are encountered more often than other natural resources at higher pressure and temperature. This high pressure and temperature lead to a higher degree of degradation of complex organic molecules. As a result, the more the organic materials are buried deeper, the higher the tendency of the organic material to be converted to gas or gas condensate. These reservoirs have grown significantly as deeper depths are drilled to hit its targets, subsequently encountering very high temperatures and pressures which are necessary for their presence (Okporiri and Idigbe, 2014).

The typical pressure of a gas condensate reservoir is mostly above or close to critical pressure when discovered. Initially, the reservoir pressure is at a point that is above the dew-point curve, so the reservoir is in gaseous state and only at this time does single-phase gas exist . However as

the production progresses, there is isothermal pressure decline and a liquid hydrocarbon phase where condensate is formed viz. when the bottom hole pressure in an existing flowing well falls below the dew-point of the reservoir fluid. The condensate accumulation tends to build up a liquid phase around the wellbore. It leads to a decrease in the effective permeability of gas into the wellbore. The low productivity associated with condensate buildup can be substantial.

1.2 Aim of the Research

To optimize the development of a new gas condensate reservoir through integrated dynamic reservoir simulation studies which will involve running several development scenarios. Maximize the recovery of oil from gas condensate reservoirs and ensure the provision of produced gas to maintain pressure.

1.3 Research Objectives

In order to achieve the above set goal, the following objectives will be considered:

1. Develop a typical Niger Delta gas condensate dynamic reservoir model.
2. Determine the impact of geometric and harmonic averaged permeability distribution on the condensate recovery.
3. Determine the number of wells to be drilled to reach production objectives.
4. Assess gas injection pressure maintenance options and its impact on recovery.
5. Run the economics analysis of the project.

Although a reservoir characteristic varies from location to location, which may likely impact the outcome of the study, this project was executed using a typical Niger–Delta gas condensate reservoir model.

1.4 Research Methodology

Integrated reservoir modeling and simulation was employed in this project. SENSOR (Coats, 2013) software was used to build a 3D model.

Reservoir Engineering and Simulation Studies

Fluid Properties or PVT Modeling

Fluids PVT characterization by means of an equation of state (EOS) matching on the available PVT experiments (CCE, CVD etc.) must be done.

- Z factor
- Liquid dropout
- Gas density
- Gas-oil ratio
- Dew point pressure etc.
- Fluid viscosity

Model Construction

A 3D reservoir model will be built with a Sensor reservoir simulator and will be used for model initialization and forecasts. A system for Efficient Numerical Simulation of Oil Recovery (Sensor) is compositional and black oil reservoir simulation software developed by Coats Engineering, Inc. This software is a generalized 3D numerical model used by engineers to, optimize oil and gas recovery processes through simulation of compositional and black oil fluid flow in single porosity, dual porosity, and dual permeability petroleum reservoirs (Coats, 2013).

A yearly time step will be used for production forecast and well completion data will be added to the well scheduling file.

The model will be initialized at the original reservoir conditions using the appropriate pressure and fluid data. A pressure maintenance strategy will be employed to maintain the reservoir pressure. The model will then be used to carry out several runs for production optimization and optimum development.

CHAPTER 2

REVIEW OF EXISTING LITERATURE

2.1 Geology of the Niger Delta

The Niger Delta is one of the World's largest Tertiary delta systems and an extremely productive hydrocarbon province. It is situated on the West African continental margin at the highest part of the Gulf of Guinea, which formed the site of a triple junction during continental break-up in the Cretaceous. The delta has been fed by the Niger, Benue and Cross rivers, which between them drain more than 10^6 km^2 of continental lowland savannah throughout its history. Its present morphology is that of a wave-dominated delta, with a smoothly seaward-convex coastline moved sideways by distributary channels.

From the Eocene to the present, the delta has prograded southwestward, by forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). Depobelts form one of the largest regressive deltas in the world with an area of 300,000 km2 (Kulke, 1995), 500,000 km3 in sediment volume (Hospers, 1965), and over 10 km sediment thickness in the basin depocenter (Kaplan and others, 1994).

Niger Delta province contains only one identified petroleum system (Ekweozor, and Daukoru, 1994, Kulke, 1995); this system is referred to here as the Tertiary Niger Delta (Akata-Agbada) Petroleum System. The biggest extent of the petroleum system is defined by the aerial extent of the fields and contains known reserves (proved reserves plus cumulative production) of 34.5 Billion Barrels of Oil BBO) and 93.8 Trillion Cubic Feet of Gas (TCFG).
Currently, most of this petroleum is in the fields that are onshore or on the continental shelf in waters less than 200 m deep and occurs primarily in large, relatively simple structures. A few giant fields do occur in the delta; the largest field contains just over 1.0 BBO (Petroconsultants, Inc., 1996a). According to the U.S. Geological Survey's World Energy Assessment (Klett and others, 1997), the Niger Delta province is ranked to be the twelfth richest in petroleum resources, with world's discovered oil and gas of 2.2% and 1.4% respectively. (Petroconsultants, Inc. 1996a)

2.2 Natural Gas

Natural gas occurs deep beneath the earth's surface and consists mainly of methane, a gas (or compound) with one carbon atom and four hydrogen atoms. It also contains small amounts of hydrocarbon liquids and non-hydrocarbon gases. The price of natural gas depends on production, imports, demand, current inventory, and oil price. Natural gas can be used as fuel or to make materials and chemicals.

According to the world Factbook, Nigeria has an estimated 180 trillion standard cubic feet of natural gas proven reserve, making it ninth in the world and largest in African as shown in Table 1 with about 50/50 distribution ratio between Associated Gas (AG) and Non-Associated Gas (NAG). Associated gas refers to the natural gas which is found in association with oil within the reservoir, while reservoirs that contain only natural gas and no oil, this gas is termed non-associated gas.

2.3 Reservoir Fluid Flow Properties

It is the study of the behavior of liquid and vapor in petroleum reservoirs as a function of pressure, volume, temperature, and composition.

2.3.1 Physical Behaviour of Gas Condensate

Reservoir fluid contains:

- methane
- intermediate C_2 –C_6,
- heavy components C_7^+

The physical state depends on, composition, reservoir temperature, and pressure.

When the reservoir temperature is greater than the cricondentherm, and surface and transport conditions are outside the two-phase envelope, the reservoir fluid is classified as a dry gas.

The reservoir fluid is regarded as wet gas when the reservoir temperature is greater than the cricondentherm and its surface conditions are in the two-phase region. The fluid can be gas condensate when the reservoir temperature is greater than the critical temperature and less than the cricondentherm. When the reservoir temperature is less than the critical temperature, the fluid is oil which can be either volatile or black oil (Rajeev, 2003). Oil contains more of heavy hydrocarbons while gas condensates contain more of the intermediates (C2 – C6). The Figure below shows the temperature–pressure relationship for the reservoir fluids and how it can be used to classify reservoir fluids.

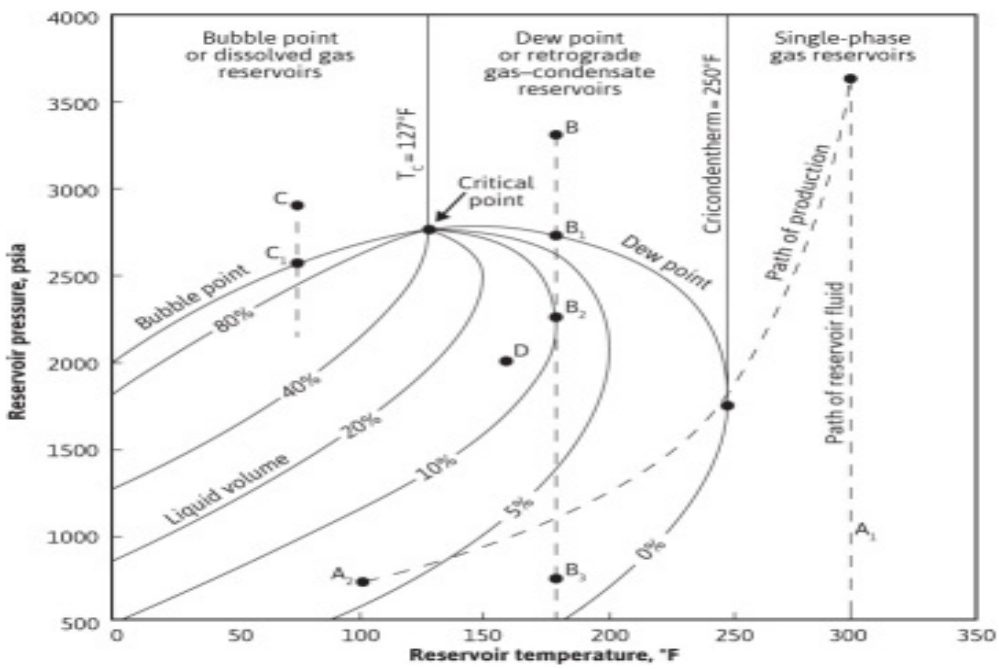

Figure REVIEW OF EXISTING LITERATURE.1: Phase diagram of reservoir fluids. Source: B. C. Craft and M.F. Hawkins (1959)

These fluid types have different ways when analyzing the reservoir, so it is important to identify the right fluid type early on in the reservoir's life. When determining and quantifying fluid type, laboratory analysis is our primary method but production information such as initial production gas-oil ratio (GOR), the color of the stock-tank liquid and the gravity of the stock-tank liquid are also useful indicators.

Table REVIEW OF EXISTING LITERATURE.1: Composition and properties of several reservoir fluids (Monograph vol. 20, SPE)

			Composition (mol%)			
Component	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile oil	Black oil
CO_2	0.10	1.41	2.37	1.30	0.93	0.02
N_2	2.07	0.25	0.31	0.56	0.21	0.34
C_1	86.12	92.46	73.19	69.44	58.77	36.42
C_2	5.91	3.18	7.8	7.88	7.57	4.11
C_3	3.58	1.01	3.55	4.26	4.09	1.01
i-C_4	1.72	0.28	0.71	0.89	0.91	0.76
n-C_4		0.24	1.45	2.14	2.09	0.49
i-C_5	0.50	0.13	0.64	0.90	0.77	0.43
n-C_5		0.08	0.68	1.13	1.15	0.21
$C_{6(i)}$		0.14	1.09	1.46	1.75	1.61
C_{7+}		0.82	8.21	10.04	21.76	56.40
			Properties			
$M_{C_{7+}}$		130	184	219	228	274
$\gamma_{C_{7+}}$		0.763	0.816	0.839	0.858	0.920
K_{WC_7}		12.00	11.95	11.98	11.83	11.47
GOR, scf/STB	∞	105,000	5,450	3,650	1,490	300
OGR, STB/MMscf	0	10	180	275		
γ_{API}		57	49	45	38	24
γ_g		0.61	0.70	0.71	0.70	0.63
p_{sat}, psia		3,430	6,560	7,015	5,420	2,810
B_{sat}, ft^3/scf or bbl/STB		0.0051	0.0039	2.78	1.73	1.16
ρ_{sat}, lbm/ft^3		9.61	26.7	30.7	38.2	51.4

2.3.1 Phase Behaviour of Petroleum Reservoir Fluid

In petroleum and natural gas engineering, attention is usually focused on regions of coexistence of liquid and vapor, which are the two phases most commonly encountered in field applications. One of the most useful phase behavior visualizations is the pressure-temperature (p-T) envelope. Each envelope represents a thermodynamic boundary separating the two-phase conditions from the single-phase region.

P-T diagrams help visualize fluid production paths from the reservoir to the surface and help in the development of best production schemes and strategies as shown in Figure 2.1. These diagrams are very important because they can describe how the reservoir fluids are transformed during production as they leave the reservoir and reach the surface. Reservoir fluids can be

classified into five categories based on the location on the phase envelope with respect to initial reservoir pressure and temperature conditions (Pi, Ti),

- Dry gas
- Wet gas
- Gas condensate
- Volatile oil
- Black oil

From Figure 2.1 reservoirs discovered in zones A, B and C belong to dry gas, condensate and black oil reservoirs respectively.

2.4 Gas Condensate Reservoir

2.4.1 Flow Behaviour of a Gas Condensate Reservoir

Gas condensate forms part of gas reservoirs and is becoming increasingly important as a source of energy. Gas condensate reservoirs have the most complex and intricate flow behaviour. This source of hydrocarbon is attributed to the production of gas and condensate liquid at the surface conditions. At the initial condition, the reservoir fluid remains as gas and when the reservoir conditions are located between the critical point and the cricondentherm of the reservoir, condensate liquid occurs as shown in Figure 2.2 below.

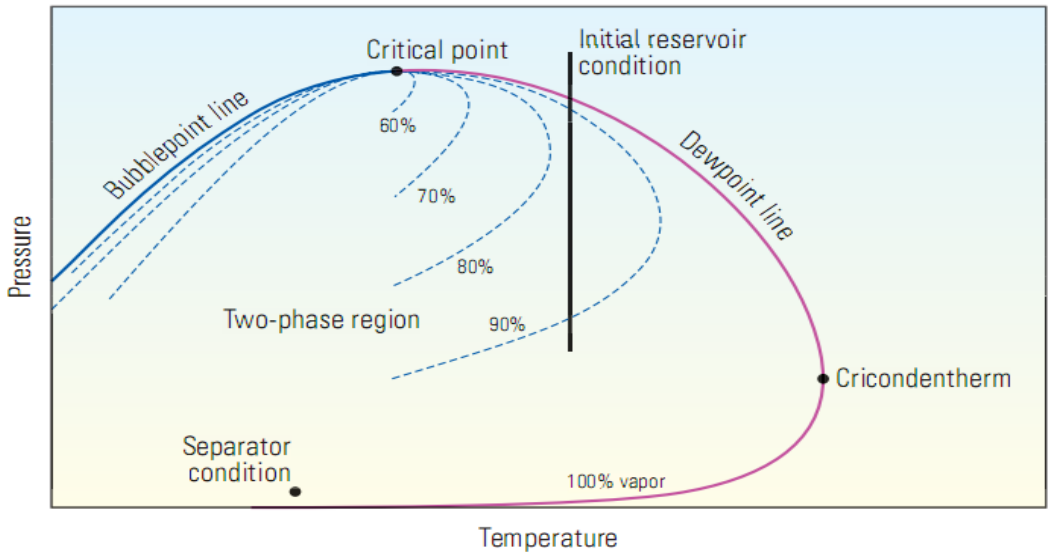

Figure REVIEW OF EXISTING LITERATURE.2: Phase envelop for a typical gas condensate well. (Li Fan, 2007)

In the single phase, Gas condensate reservoir is primarily gas but as pressure declines below dew point liquid starts to drop out of the gas phase near the wellbore as shown in Figure 2.3 below.

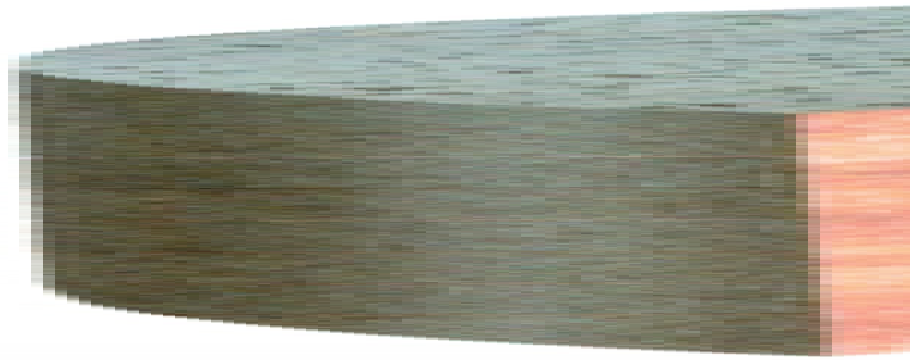

Figure REVIEW OF EXISTING LITERATURE.3: Liquid condensation in the well region (Li Fan, 2007)

Condensation continues as the pressure declines until much liquid accumulates, even up to the critical condensate saturation. The resultant effect of this condensation is a restriction to the flow of gas, and this rich gas becomes leaner towards the perforations leading to low gas productivity and low recovery of condensate. The extent of decrease in gas permeability in the wellbore region depends on fluid phase behaviour and relative permeability characteristics. According to Fevang and Whitson (1995), the flow behaviour of gas condensate reservoirs can be studied on three flow regions.

Condensate reservoir type shows different flow behaviour from oil and gas reservoirs as a result of retrograde condensation. Field experiences have shown that condensate banking will result in a sudden decline in production at a point in time (Taufan and Adrian 2007, Afidick et.al. 1994, Lee and Cheverra 1998). Taufan and Adrain (2007) conducted compositional simulation on gas condensate reservoirs to gain more understanding on retrograde gas reservoir performance. In their parametric study, the influence of production rate, gas composition, critical liquid saturation, absolute permeability and rate scheme on condensate blockage were investigated. The most influential factors were permeability and critical condensate saturation. It was found that even if the maximum liquid drop out derived from laboratory Constant Volume Depletion analysis is small, the maximum liquid saturation in the pore space could be several times higher. The model used in the study assumed the following constraints: homogeneous and isotropic reservoir, gas composition at initial condition are the same in the entire reservoir, initial pressure in the entire reservoir is the same, EOS is valid in the whole reservoir, capillary pressure is negligible, non-Darcy effects are neglected and reservoir temperature is constant. He used two models,fluid and reservoir models to study the reservoir behaviour. The fluid model employed the Peng-Robinson equation of state (EOS) to evaluate the gas and liquid volumes at any given pressure and at reservoir temperature. The predicted EOS PVT values were used to match the PVT values obtained from the field through laboratory experiment. They designed a reservoir model using Cartesian grid block. From the study, the main cause of condensate blockage is pressure decline around the wellbore below dew point pressure. He evaluated the productivity index of the well and noted that there was a decline in productivity as a result of pore plugging due to liquid condensation. The higher the plateau rate, the more condensate ring saturation and ring radius increases until a certain limit. The more the heavy components condense from the reservoir gas, the worst condensate blocking was experienced for the same pressure decline. Therefore, maximum condensate ring saturation is mainly influenced by critical liquid saturation.

The physical state depends on, composition, reservoir temperature, and pressure. The reservoir fluid contains: methane, intermediate C_2 –C_6 and heavy components C_7^+.

2.4.2 Compositional Modeling of Gas Condensate Reservoirs

A good understanding of fluid flow through a porous medium requires a good prediction of physical properties and the fluid phase behaviour. A typical representative gas condensate fluid consists of many components which are dispensed between the vapour and liquid phase under equilibrium phase changes. The phase behaviour and fluid properties of such systems depend on the pressure and also on fluid composition at the reservoir temperature. Because of that, the study of flow behaviour in these systems requires a compositional model to describe the fluid phase behaviour and properties. A compositional model uses equations of state (EOS) to estimate the phase behaviour and physical properties of the fluid. An equation of state presents a theoretical relationship between pressure, volume, and temperature. Peng-Robinson and Soave-Redlich-Kwong equations of state (EOS) are commonly used in the petroleum industry.

Shi (2009) developed a methodology to increase the gas and condensate productivity of gas and condensate from condensate reservoirs. The work reports that the combination of condensate phase behaviour and rock relative permeability results in a compositional change of the reservoir fluid as heavier components separate into the condensed liquid, while the flowing gas phase becomes leaner in composition. He quantified this effect, developed a scientific understanding of the phenomenon and used the results to investigate the ways to enhance the production by controlling the liquid composition that drops out from the gas and is closed to the well. He optimized the producing pressure which caused a lighter liquid to be conducted in the reservoir, hence the high productivity. The work was focused on the flowing phase behaviour and the impact of flowing compositional changes. The research work used experimental measurements of gas condensate flow, as well as compositional numerical simulations to study the flow of fluid from condensate reservoirs. The simulation was aimed at obtaining the impact of producing scheme on the condensate banking and composition variation. Different strategies were compared and the optimal producing sequences were suggested for maximum condensate recovery. The result of the research showed that reservoir fluid composition varies significantly as a function of fluid phase behaviour and the producing sequence.

2.5 Mobility and Pressure Drawdown of Hydrocarbon Liquids

2.5.1 Mobility and Pressure Drawdown

To model the mobility of the condensed phase which drops out from the gas during depletion, you need to understand the phase and flow behaviour of fluids. Productivity above the dew point pressure depends on the reservoir mobility ratio, represented as:

$$Mobility\ Ratio = \frac{Permeability \times thickness}{viscosity}$$ Equation 2.1

From the equation, it shows the higher the viscosity of fluid, the less mobile it is.

Below the dew point, it is controlled by the critical condensate saturation, the shape of the condensate and gas relative permeability curves, and non-Darcy flow effects. (Hashemi et al., 2004). In gas condensate reservoirs the condensate becomes mobile when the condensate saturation is greater than the critical condensate saturation.

Basic understanding of the phase and flow behavior interrelationship is needed to model the mobility of the condensed phase which drops out during depletion.

Fevang and Whitson (1995) in their studies showed that retrograde condensate occurs when reservoir pressure around a wellbore drops below the dew point pressure. Three regions are created with different liquid saturation. For a given producing condition, one, two, or all three regions may exist. These three regions define pseudosteady-state flow conditions, meaning that they represent steady-state conditions at a given time, but that the steady-state conditions gradually change during depletion. The three regions are identified with a block representation of the mobile phases and condensate accumulation in the three regions as shown in Figure 2.5

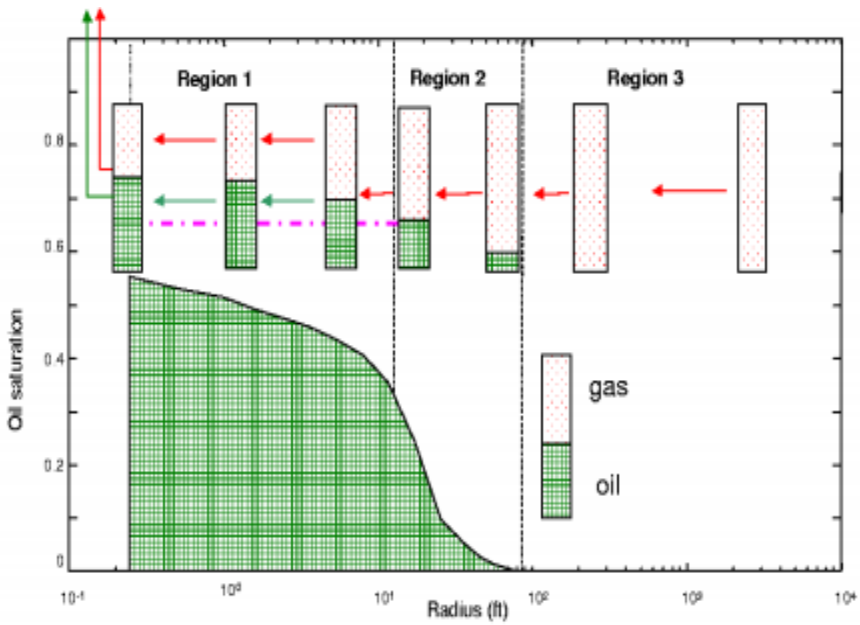

Figure REVIEW OF EXISTING LITERATURE.4: Schematic gas-condensate flow behavior (Roussennac, 2001)

Region 1: Both gas and liquid phases are mobile that is, the condensate saturation in this region is above the critical condensate saturation (Scc). The Gas to liquid ratio within Region 1 is constant throughout. This means that the single phase gas entering this region has the same composition as the produced wellstream mixture. Furthermore, the dew-point of the producing wellstream mixture is the same as the reservoir pressure at the outer edge of Region 1. It is the main source of low well deliverability in a gas-condensate well. There is a reduction in the gas relative permeability region due to condensate buildup. Although condensate buildup starts from Region 2, the liquid phase is not able to flow. Two-phase flow in region 1 is mostly the main cause of gas relative permeability reduction and its size increases with time. For steady-state conditions, the condensate saturation in this region is determined (as a function of radius) specifically to ensure that all liquid that condenses from the gas phase entering it has sufficient mobility to flow through and out of this region, without any net accumulation. Since the composition of the flowing mixture is the same throughout this region, the liquid saturation could be calculated by a constant composition expansion of the producing fluid. The amount of liquid dropout in this region depends primarily on the production rate and the PVT properties of the gas-condensate mixture.

Region 2: This is the intermediate zone where condensate dropout starts and it defines a region of net accumulation of condensate. When the condensate saturation is below the critical value (Scc), gas is the only phase flowing in this region because oil mobility is zero (or very small). The condensate saturations in Region 2 are closely approximated by the liquid dropout curve from constant volume depletion (CVD) experiment, corrected for water saturation. The size of this region is largest at early times just after the reservoir pressure drops below the dew-point. Region 2 decreases with time because Region 1 keeps expanding. The importance and size of region 2 is more than that of a lean gas-condensate. The critical condensate saturation (Scc) also affects the size of Region 2. The size of this region increases for increasing values of Scc. Hence, Scc is important in studying the changing composition of the reservoir fluid because Region 2 has a constantly changing composition of the reservoir fluid. The main consequence of this region is that, producing wellstream composition (GOR) is leaner than calculation by a simple volumetric material balance (e.g., CVD measurements).

Region 3: This is the region farthest away from the wellbore where reservoir pressure is more than the dew-point pressure of the original fluid. Single-phase gas is present and hence is the only mobile phase.

2.5.2 Coexistence of Flow Regions

In Region 3, at the Initial conditions, the reservoir pressure is above the dewpoint. As the reservoir pressure declines, Regions 2 and 1 appear as a result of the condensate buildup across the reservoir. Region 1 exists when the bottom hole flowing pressure (BHFP) is less than the dew-point, after a short transient considered to buildup the steady-state saturations in Region 1. Region 2 normally exists together with Region 1 after reservoir pressure drops below the dew-point. Region 3 does not exist in this case. All three regions exist for reservoirs that are slightly undersaturated and bottom-hole flowing pressure (BHFP) is less than the dew-point. Region 2 may “not appear” or have little effect for highly undersaturated reservoirs. For very rich gas condensates, Region 2 is negligible. Regions 2 and 3 cannot exist in the absence of Region 1 (after steady-state conditions are reached). For a very rich (near-critical) gas-condensate, region 1 may exist throughout its drainage area (in the absence of Regions 2 and 3), after reservoir pressure drops below the dew-point (Rajeev, 2003).

2.6 Gas Condensate Well Deliverability

Gas condensate reservoirs are characterized by the production of both surface gas and varying quantities of stock-tank oil, commonly referred to as condensate. Recovery of condensate is a key consideration in developing gas condensate reservoirs because of the added economic value of produced condensate, in addition to gas production. The condensate produced becomes the only potential source of income when there is an extreme case of a non-existent gas market.

A region of relatively high liquid saturation will develop close to the wellbore when bottom-hole flowing pressure (BHFP) drops below the dewpoint pressure. This high liquid saturation results in reduced gas relative permeability and reduced well deliverability. Well deliverability is the relation defining a well's production rate as a function of some constraining pressure.

The effect of condensate blockage depends on:

(1) Relative permeability

(2) PVT properties, and

(3) How the well is being produced.

Fussell (1973) presents EOS compositional simulations of radial gas condensate wells producing by pressure reduction below the dewpoint. He shows that the effect of condensate accumulation on well productivity and that, the O'Dell-Miller equation dramatically overestimates the well deliverability loss due to condensate blockage, compared with simulation results. He also evaluates the effect of phase behaviour and relative permeability characteristics on production performance.

2.7 Gas Condensate PVT Behaviour

Gas condensate reservoirs are caged out of oil and gas reservoirs based on their PVT properties, which result in different flow behaviour of the reservoir fluid. Engineering of gas condensate fields ranges from 70% -90% traditional gas engineering (Whitson et al., 1999). The major difference between gas condensate and dry gas reservoir is the complex behaviour condensate reservoirs exhibit due to the existence of the multi-phase, which is two-phase flow in the reservoir and an additional income derived from surface condensate productions.

Two issues that need attention in gas condensate reservoirs are:

- Variation of condensate yields during the life of the reservoir.

- The effects of the gas-oil flow phase on productivity in the vicinity of the well bore variation, in condensate compositions and in two-phase relative permeability close to wellbore are all controlled by the PVT properties of the fluid.

The PVT properties which control fluid production during pressure depletion are viscosities of the two phases, Z-factor, liquid dropout and compositional variation of the heavier components with pressure. In gas cycling projects, it is essential to quantify the following phase behavior, vaporization, condensation, and near well miscibility which develops in gas cycling below the dew point. Different experimental models have studied the PVT behaviour of gas condensate reservoirs. Amongst the experimental studies are constant volume depletion, constant composition expansion, gas chromatography, density and viscosity studies. The PVT studies primarily conducted to investigate gas condensate fluid are the constant composition expansion (CCE) to obtain the dew-point and constant volume depletion (CVD) to simulate reservoir production behaviour.

2.8 Gas Condensate Relative Permeability

Relative permeability is one of the most important parameters that governs the productivity of gas-condensate reservoirs below the dew point pressure (Pope et al.1998, Mulyadi et al. 2002). The fundamental works of Darcy are still the major theoretical framework for evaluation of relative permeability of flow in a porous media. Multiphase flow in the well bore poses major challenges to production engineers because of the difficulty in characterizing the prevailing flow regime which determines the appropriate pressure drop calculation type to be used (Sadeghi, Gerami and Masihi 2010). This is related to the relative permeability issues in the reservoir.

The flow behavior of gas condensate systems is further complicated by the unique dependency of near wellbore relative permeability on velocity and interfacial tension. Effective permeability reduction at high velocities due to negative inertia was first introduced by Forchhiemer (1914). The positive coupling effect, which refers to the improvement of relative permeability as velocity rises and/or IFT decreases, has been proven theoretically and experimentally to be due to the simultaneous coupled flow of the gas and condensate phases with intermittent opening and blockage of gas passage by the condensate at the pore level (Jamiolahmady et al. 2000, 2003). Experimental work performed by Henderson et al (2000) shows that inertia is dominant for a saturated core with 100% gas. However, the condensates are formed when the impact of inertia

reduces. They showed that increasing velocity in high condensate saturation improves the gas relative permeability due to coupling, but for low condensate saturation the same velocity alteration will reduce the gas relative permeability due to inertia.

In fact, the importance of positive coupling and negative inertial effect on the gas condensate relative permeability is a complex function of many parameters such as rock properties, fluid properties (viscosity, density, fluid richness, interfacial tension) and pore velocity. In reality, these two opposite effects are always in competition.

Many empirical correlations have been developed to predict the dependence of relative permeability on velocity and IFT (positive coupling and negative inertia). Ghahri, (2010) used a generalized correlation conducted by Jamiolahmady et al. (2009). The main advantages of this correlation compared to the aforementioned ones are that, it uses either universal parameters that can be estimated from readily available petrophysical data and it also accounts for the combined effect of inertia and coupling.

In this correlation, gas relative permeability is interpolated between a miscible curve and base curve, both corrected for the effect of inertia, using a generalized interpolation function. The correlation is based on the relative permeability ratio ($k_r = k_{rg} / k_{rt}$ where $k_{rt} = k_{rg} + k_{ro}$) as the main variable, which is closely related to fractional flow. The condensate relative permeability can be calculated using the definition of relative permeability ratio. It should be noted that in gas/condensate systems, fractional flow is directly related to reservoir fluid composition and pressure at the steady-state conditions generally prevailing near the wellbore, hence, making it much more practically compared to saturation, which depends on core characteristics

2.9 Enhanced Gas and Condensate Recovery

Depleted gas and condensate reservoirs can be revitalized by gas injection and wettability alteration. Dry gas used in enhanced gas recovery has wide applicability in reservoir pressure maintenance for preventing condensate dropout. Gas cycling is an aspect of enhanced gas recovery scheme. Gas cycling counter balances pressure drop, decreases dewpoint pressure and evaporates condensate. Experimental studies show the effect of gas cycling on the reservoir fluid phase behavior and produced gas properties. These tests are used to simulate the different industrial enhanced gas and condensate recovery scenarios like dry gas, produced gas, carbonated gas or nitrogen injection; pressure maintenance, wellbore treatment (huff and puff) and CO2 sequestration (Furcht et al. 2010). Furcht etal. (2010) in their experimental modeling of

enhanced gas and condensate recovery stated that, experiments with injection gases of different composition identical with accessible injection gas reserves provide realistic input databases for industrial Enhanced Gas Reservoir (EGR) engineering computations. They reported the simulation can be used to determine the efficiency of condensate recovery and for the utilization of gas storage and pressure maintenance. Gas cycling can alter the phase behavior of reservoir fluids in the following ways:

- The Mixing of reservoir fluid and the dry injection gas causes the dewpoint pressure to decrease.
- The retrograde condensate diminishes because of pressure maintenance effect.
- The injected gas can re-vaporize the condensate in the reservoir.

  Hearn and Whitson (1995) presented a reservoir modeling approach for a carbonate reservoir in Safah field in Oman. The work illustrates how engineering tools can be used to evaluate the technical feasibility and economics of high-pressure gas injection in a carbonate reservoir. The engineering tools employed are EOS and grid refinement models. The EOS model was used to simulate experimental PVT data, matching miscible and immiscible slim tube results and pseudoization of components used in the EOS model to reduce the computational requirements. The grid refinement model was used to investigate the numerical grid effect, displacement mechanism, and injection pressure. The purpose of this work was to illustrate the evaluation process, show how simulation can extend the experimental result, determine displacement mechanism and show the effect of operating variables on Safah oil recovery. From the study, the authors reported that miscible displacement of the oil with rich gas injection could recover more oil thanthe lean gas injection in Safah field. They also reported that the pseudoized characterization (8 components) proved to be as accurate as the original 15 components characterization used for describing standard PVT behavior, near critical behavior and combined vaporization/condensation effects associated with developed miscibility mechanism.

2.9.1 Gas Injection in Gas Condensate Reservoirs

Due to the heterogeneity of a reservoir, condensate blockage occurs which causes low gas productivity and loss of valuable condensed liquid as the condensate content in the formation increases (Izuwa et al, 2014). Exploitation of gas condensate reservoirs without pressure maintenance results to the recovery of high surface gas, and loss of valuable fractions of heavier

hydrocarbons. (Ayala and Ertekin, 2005) Condensate adds extra economic value in addition to the producing gas. According to El-Banbi and McCain, producing a gas condensate reservoir by pressure depletion will result in a high recovery for the gas but low recovery for the condensate. This means the richer in condensate, the more liquid drops out of the gas in the reservoir. Condensate becomes immobile when it is below the critical condensate saturation thereby the most practical technique of stimulating this kind of reservoir to improve the recovery of gas and condensate is by, gas injection. This can be of two kinds, reinjection of miscible hydrocarbon gas (dry gas or produced gas) and injection of immiscible non-hydrocarbon gases. Whether miscible or immiscible injection process is used, gas injection is certainly one of the most efficient improved recovery techniques. It gives 90% microscopic efficiency (Bardon, 1995). Though the macroscopic efficiency is not very tremendous, it is higher than that obtained by water flood. New approaches employed to improve macroscopic sweep efficiency are the techniques of water-alternating-gas and simultaneous injection of gas and water. The combined injection of gas and water results in the three-phase flow effects which reduce the gas mobility but allow a sharper gas growth. In water-alternate-gas injection, the bottom of the reservoir is swept by the water while maintaining the pressure and gas sweeps at the top of the reservoir. This gives high sweep efficiency.

Kenyon and Behie (1987) presented a report on the comparative study on the gas cycling of retrograde condensate reservoirs. In their report, nine companies participated in an artificial modeling study of gas cycling in a rich retrograde gas condensate reservoir. They discovered that surface oil rate predictions differed in the early years of cycling but agreed better in later years of cycling. The amounts of condensate drop-out near the production well and its rate of evaporation varied widely among the participating companies. The companies used their in-house developed models in the evaluation. The explanation for this variation stated by the authors was the difference in techniques used to obtain the K-values.

Ayala and Ertekin (2005) conducted a study on gas cycling performance in gas condensate reservoirs using Neuro- simulation. Well producing schemes may impose significant influence on the phase behaviour. They showed major progress in tackling problems related to production optimization. In their work, parametric studies were conducted to identify the most influential reservoir parameters and fluid characteristics in the establishment of the optimum production strategies for implementation of pressure maintenance in gas and condensate system. Also, they

reported that pressure maintenance can be economically justified if the reservoir pressure is above dew point or there is re-vaporization of any condensate that might have condensed.

2.10 Phenomena Affecting Near Well Behaviour

Most of the standard simulations do not consider the effect of some phenomena affecting near well behavior. This had led to an overestimation of the effect of liquid blockage and under -prediction of well productivity.

2.10.1 Interfacial Tension

Experimental studies have demonstrated the effect of interfacial tension on relative permeability. Mott, (1997) in his work demonstrated that significant improvement occurs in relative permeability at low interfacial tension. From the report, threshold interfacial tension value of 0.1mN/m can cause changes in relative permeability values. Low interfacial tension effect could be of considerable importance in miscible gas injection/flooding and could be modeled in most compositional simulations. Also, Li and Firoozabadi (1998) in their study on the effects of interfacial tension (IFT) on relative permeability concluded that both gas and liquid relative permeability decreases with increase in interfacial tension, gas phase relative permeability being more sensitive than liquid phase relative permeability. This result is in accord with the experimental data of Henderson et al. (1993), the authors found that the relative permeability of both phases decreased with increase in interfacial tension. At low reservoir pressure when productivity is a concern, changes in near well mobility are functions of low/moderate interfacial tension and high flow rate resulting in a high capillary number. Low interfacial tension occurs at high pressure for rich gas condensate at about 1000psi of dew point pressure (Mott, 1992). Thomas et al. (1995) worked on optimizing production from a gas condensate reservoir. Their work added color to the description of the phenomena that are at work in rich gas condensate reservoir. They found out that specific parameters like interfacial tension, mobility effect, pore size distribution and composition changes are important in the optimization of gas condensate wells. Interfacial tension is directly proportional to the capillary pressure, as the radius of the pore throat which contains the condensate decreases, the capillary pressure holding the liquid in the pore increases. To produce the condensed liquid from the small pore throats, either a very

high differential pressure driving force or low interfacial tension is required. Condensed liquid with high interfacial tension is required in such cases to produce the liquid.

2.10.2 High Flow Rate

The effect of flow rate on gas condensate relative permeability shows that both relative permeabilities of the two phases increases with an increase in pressure drop (Chen et al., 1995). Further research (Henderson et al., 1993) also revealed that relative permeability of both phases increased with the increase in flow rate, but they noted that liquid relative permeability is less sensitive than gas relative permeability.

A number of experimental measurements have shown that relative permeability is increased at a high capillary number (Henderson et al., 1995, Chen et al., 1995). Capillary number Nc is expressed as:

$$N_c = \frac{flow\ rate\ \times\ viscocity}{IFT} \qquad \text{Equation 2.2}$$

This relationship expresses a direct proportionality of capillary number to flow rate. High values are observed in the vicinity of the wellbore while high flow rate improves well productivity. Non-Darcy or inertial flow effects reduces well productivity. Single well studies have been used to assess the impact of high capillary number and non-Darcy flow effects on well productivity. According to Mott (1997), high capillary numbers lead to a significant increase in bottom-hole flowing pressure and the well productivity increases by a factor of 2.

2.11 Reservoir Simulation

2.11.1 Types of Reservoir Simulation Model

When the reservoir pressure is larger than the dew point pressure of the fluid in a gas condensate, the wellstream composition does not change significantly. There is a great change in the composition of the producing wellstream when the reservoir pressure decreases below the dew point due to the retrograde condensate drop out in the reservoir. A compositional model is more preferable than a black-oil simulation model because a black oil may not give accurate results

when the component exchange between the oil and gas phase becomes more complex. A compositional reservoir simulator can model the component exchange between gas and liquid phase more accurately. Coats (1985) showed that black-oil simulators can be used for gas cycling in gas condensate reservoirs when the reservoir conditions are above the dew point. These findings were supported by Fevang et al. (2000) for lean to medium rich gas condensate fluids.

2.11.2 Equation of State (EOS)

According to Whitson and Brulé, 2000, Equations of state (EOS) is a mathematical relation between pressure, volume, and temperature. It can accurately describe the phase behavior for pure substances and mixtures. Since the first introduction of Van der Waals EOS in 1873, many cubic EOS have been proposed in the literature. The two cubic EOS widely used are:

- Soave-Redlich and Kwong (SRK) equation of state (1972)

$$P = \frac{RT}{v-b} - \frac{a(T)}{v(v-b)}$$

Equation 2.3

The constants a and b are “attractive” and “repulsive” forces between molecules respectively, T = temperature, R = universal gas constant and v = molar volume. The SRK EOS overestimates liquid volumes and underestimates liquid densities of petroleum mixtures.

- Peng-Robinson (PR) equation of state (1976)

$$P = \frac{RT}{v-b} - \frac{a(T)}{v(v-b)+b(v-b)}$$

Equation 2.4

The Peng-Robinson EOS improved the liquid density predictions compared to the Soave-Redlich and Kwong EOS. To perform EOS calculations, the minimum input data are molar composition, molecular weight, and specific gravity of the heaviest components (Whitson et al., 1999). With this input as a minimum requirement, an EOS can calculate (practically) any phase and volumetric properties. In other words, bubble point/dew point at Specified temperature, P-T diagrams, densities, Z-factors, separator GOR and surface gravity can be determined. (Pål Lee, 2013)

2.12 Economics Analysis

It is a systematic approach to determining the optimum use of scarce resources involving, comparison of two or more alternatives in achieving a Specific objective under the given assumptions and constraints. It helps you to determine if a project is a long-term, profitable asset and good fit to execute the project. Many oil and gas industries select development projects based on the best economic outcome of the projects by maximizing its net present value over the life of the reservoir after optimum.

2.12.1 Net Present Value

It helps to compare the value of a certain amount of money today to the value of that same amount in the future and vice versa, taking into consideration inflation and returns. For instance, if one is given an investment opportunity, the NPV can be used to analyze the profitability of the project and also to make decisions with regards to capital budgeting.

$$NPV = \sum_{t=0}^{n} \frac{CF_t}{(1+d)^t}$$

Equation 2.5

Where:

CF_t = Cash Flow at a period "t"

Dt= Discount rate for period "t"

N = Last period of economic horizon

2.12.2 Cash Flow

Every project has cash receipts and disbursements into or out of the treasury respectively. Mathematically Net Cash Flow = Cash inflows – Cash outflows

An example of Cash Inflow is gross Revenue and Cash Outflow, viz a technical cost which comprises of Operational expenditure (OPEX) and Capital expenditure (CAPEX).

Capital expenditure (CAPEX): These are expenditures that can be grouped into tangible and intangible costs. Tangible costs are usually capitalized and depreciated for after tax calculation purposes, and Intangible costs are usually expensed through amortization for calculation purpose

Operational expenditure (OPEX): It is the hidden cost of being in business,viz. internal costs, no money is paid out.

Revenue is the price multiplied by a marketed volume of hydrocarbon.

During investment decision-making:

If NPV > 0 Project accepted

If NPV < 0 Project rejected

This means the project with the highest NPV is favorable.

CHAPTER 3

STUDY METHODOLOGY

3.1 Outline of Methodology

The optimization of the compositional model for gas condensate in the Niger Delta Field was developed by using industry-standard software. These softwares were used to understand and simulate the conditions of the reservoir. This work is integrated into two segments, the reservoir, and fluid pressure. The volume and temperature (PVT) models were first built and followed by a dynamic simulation study in order to determine the optimal development model for gas condensate reservoirs. The simulation work of the thesis is done with the use of the commercial numerical simulator software, SENSOR. It is a dynamic reservoir simulator developed by Coats Engineering, Inc., (Coats, 2013). It works efficiently on black oil and multi-component compositional fluids.

3.2 Reservoir Model

Three major parts of compositional modeling of the gas condensate reservoir study were carried out. These are PVT data modeling, reservoir simulation, and pressure maintenance.

3.2.1 PVT Modeling

PVT model was generated through the results from the Constant Composition Expansion and Constant Volume Depletion experiments, using industry accepted methodology.

Fluid samples obtained from the Niger Delta condensate reservoir were characterized by using the Peng-Robinson EOS (Equation of state), Standing and Katz, and Lorenz Bray and Clark. The separate fluids were recombined into reservoir fluid which contains 22 components. The reservoir fluids were defined by entering its components and the corresponding mole fraction. The 22 components were lumped into 12 components that is, the heavy ends which are heptane plus (C7+) were lumped into one pseudo component to resolve the uncertainty because the higher the number of carbon, the higher the uncertainty on the exact composition making twelve components. The PVT simulator was used to match EOS closely to the Saturation Pressure of the laboratory derived data. EOS tuning is used to resolve the uncertainty in the fluid properties. The pseudo component was split into three fractions in order to achieve a better characterization. Binary interaction coefficient was applied in regression of the EOS parameters to reduce the

difference between the experimentally derived data and EOS predicted value. The components were then grouped into seven to speed up the compositional simulation. For large numbers of components, the computing time needed to solve the flash equations may be as great as the time needed to solve the flow equations.

3.2.2 Reservoir Simulation

It is a versatile tool for reservoir engineering. It helps finalize the critical management decisions such as the number of wells and the location to be drilled, pressure maintenance schemes, and the design of facilities. Sensor 6K software was used to generate a full compositional 3D dynamic simulation model from the Niger Delta Field.

It is a 3D compositional reservoir model which has grid dimensions of 21 x15×3 arrangement, which correspond to the x, y and z directions. Gravity effects, capillary forces, skin factor and non-Darcy effects were neglected. The model is shown in Figure 1 and has three geologic layers. The thicknesses varies among the layers from 55, 15, and 20 ft. in layer 1, 2 and 3, respectively.

3.3 Rock and Fluid Properties

Porosity was kept constant throughout the reservoir at a value equal to 20%. Permeability varies in the x and z directions. The permeability of y-direction was the same as that of the x-directions. The fluid production in this reservoir is constrained by a minimum bottomhole pressure of 200Psia. The well configuration is 0.292ft in diameter for Region 1, and 0.24 for Region 2. The production rate of each well is 40000 MSCF/D. The injection rate was varied based on the percentage of total gas production. The reservoir properties and the reservoir grid distribution of gas condensate reservoir model are listed in Table 3.1.

Table STUDY METHODOLOGY .2: Reservoir properties and grid dimensions

GRID DIMENSIONS			
Surface area, ft^2	945		
Grid model	2D		
No of cells, ft			
X Direction	21		
Y Direction	15		
Z Direction	3		
Well radius (rw), ft			
REGION 1	0.292		
REGION 2	0.24		
Thickness, ft			
X Direction	20		
Y Direction	30		
Z Direction	50		
Depth of top of the reservoir, ft	10100		
ROCK AND FLUID PROPERTIES			
Porosity	30%		
KX ZVAR, mD	163.88	122.21	60.08
KY EQUALS KX, mD			
KZ ZVAR , mD	142.066	104.19	87.9
WATER			
Water FVF initial, rb/stb	1.01924		
Water compressibility, 1/psi	3.16E-06		
Water density, ft./cuft	62.4		
Water viscosity, cp	0.475077		
Rock compressibility, 1/psi	2.34E-05		
Reference pressure for water FVF, Psia	4609.3		
AQUIFER			
Pore Volume aquifer Compressibility, 1/psi	9.23E+08		
Initial Aquifer Pressure, Psia	4529		
Depth, ft	10224		
Aquifer total PI, rb-cp/d-psi	10000		
INITIALIZATION			
INITIAL 1			
Initial pressure , Psia	4609		
Reference depth , ft	10239		
HWC, ft	10239		
PSAT, Psia	4609		
DEPTH, ft	10224		
z	0.945		
INITIAL 2			
Initial pressure , Psia	4609		

Reference depth , ft	10140
HWC, ft	10140
PSAT, Psia	4529
DEPTH, ft	10140
z	0.945
WELL DATA AND CONTROL PARAMETERS	
Skin factor	0
Limiting bottom hole pressure, Psia	200
Target well gas rate, MSCF/D	5000
TIME SPECIFICATIONS	
Simulation period, days	5475

The model developed was used to evaluate the different production strategies for maximum condensate production from the designed reservoir. Four scenarios were simulated to obtain a production data of the Niger Delta field for fifteen years.

Table STUDY METHODOLOGY .3: Shows the various cases used for the simulation

SCENARIO	TYPE OF WELL	NUMBER OF WELLS
SC1	VERTICAL WELL	2
SC 2	HORIZONTAL WELL	2
SC GAS CYC 1	VERTICAL WELL	3
SC GAS CYC 2	HORIZONTAL WELL	3

After fifteen years of production, the produced gas was then injected into the reservoir to maintain the reservoir pressure.

Production and Injection constraints

The Production and Injection constraint used in the base Case of this model are:

- Maximum gas production rate for each producing well was 40MMSCF/Day
- Maximum field pressure was 4609 Psi

3.4 NPV Analysis

An economic analysis of the various scenarios was carried out in Microsoft excel sheet.

CHAPTER 4

RESULTS AND DISCUSSION

This chapter presents a detailed discussion of the various results which were obtained from the simulation for optimization of the Niger Delta Field. Two scenarios were studied and these scenarios considered both horizontal and vertical well placement. The results from the two scenarios were then compared with each other to draw reasonable conclusions. The simulation was run for fifteen years for natural depletion and later, pressure maintenance mechanism was introduced to boost the reservoir pressure to ascertain optimum recovery.

4.1 Matching of Laboratory Data and Peng-Robinson Equation of State

The results obtained from Separator and Constant Composition Expansion was matched with the Peng-Robinson EOS.

The reservoir conditions are as follows:

- Initial Pressure – 4609 psi
- Dew Point Pressure- 4609 psi

- Condensate to Gas Ratio - 46.6bbls/MMCF
- Reservoir Temperature – 192.3 °F

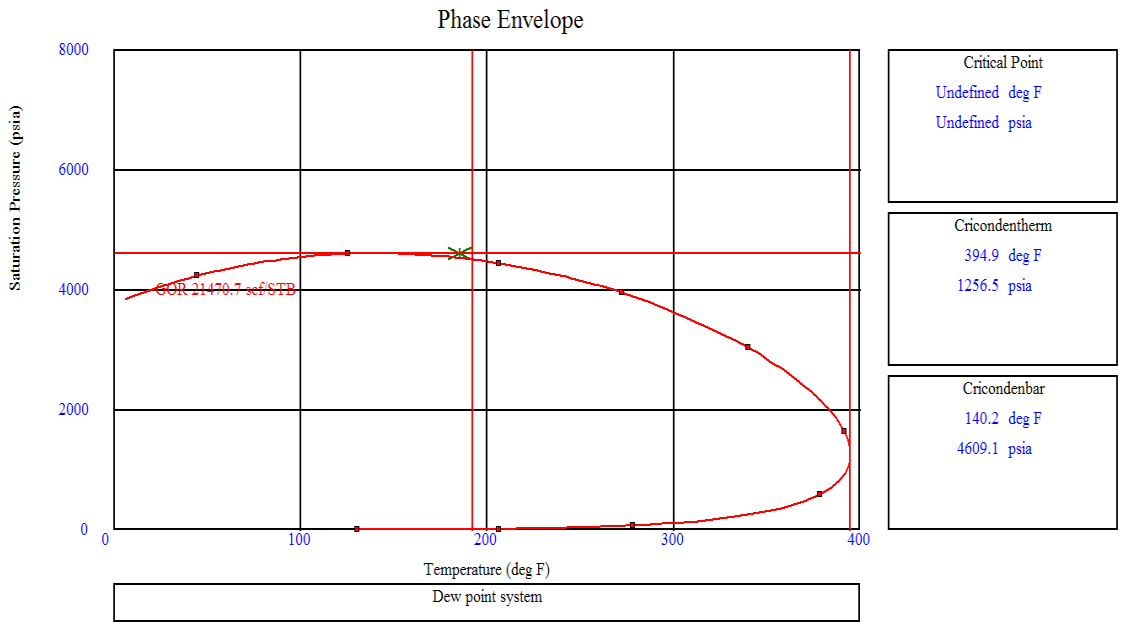

Figure RESULTS AND DISCUSSION.5: The phase diagram of the reservoir fluid

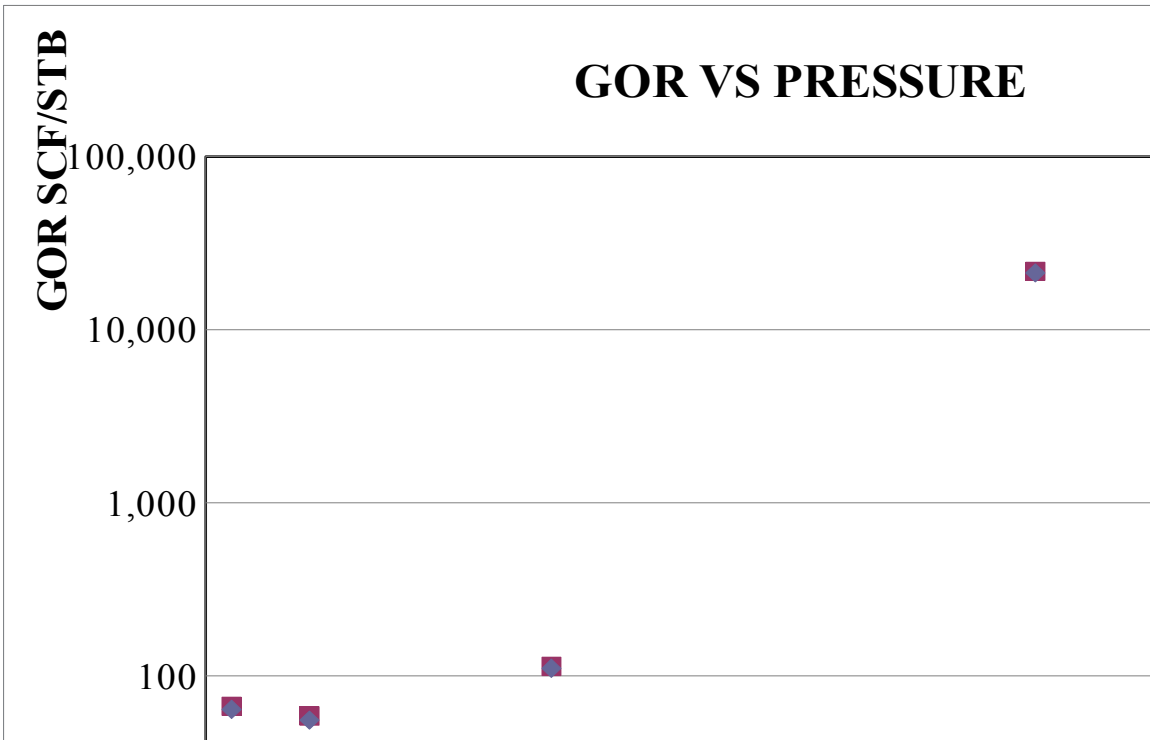

Figure RESULTS AND DISCUSSION.6: Experimental and calculated GOR factor data for Separator @192.3oF

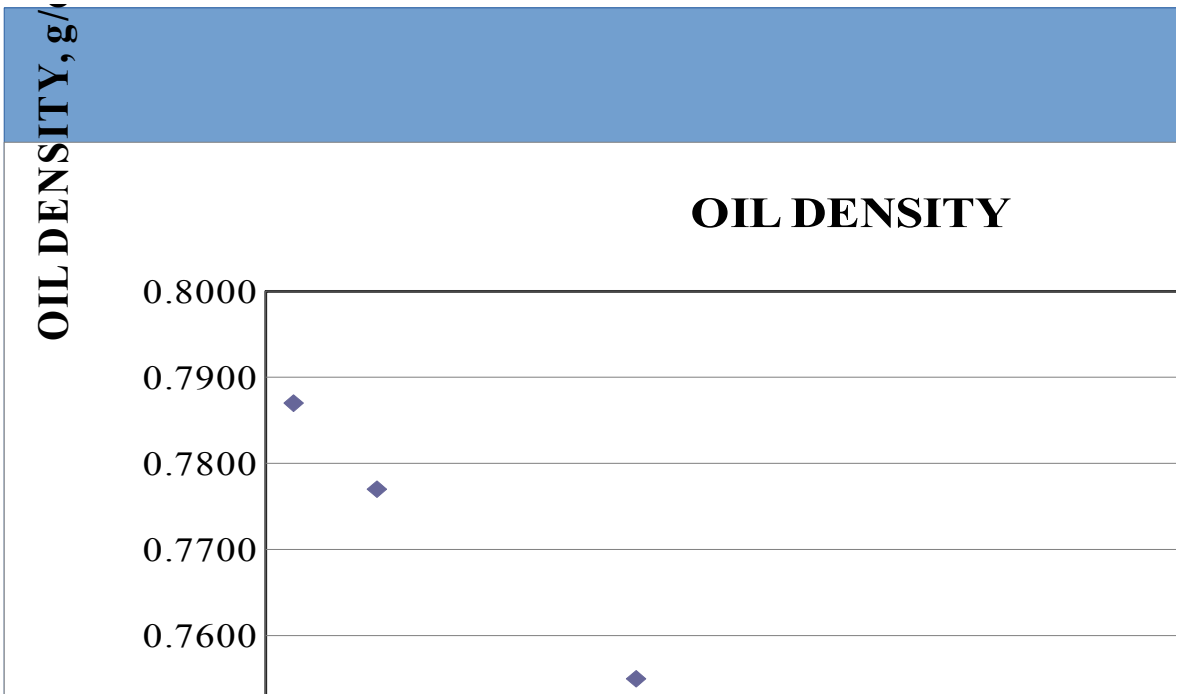

Figure RESULTS AND DISCUSSION.7: Experimental and calculated oil density for Separator @192.3oF

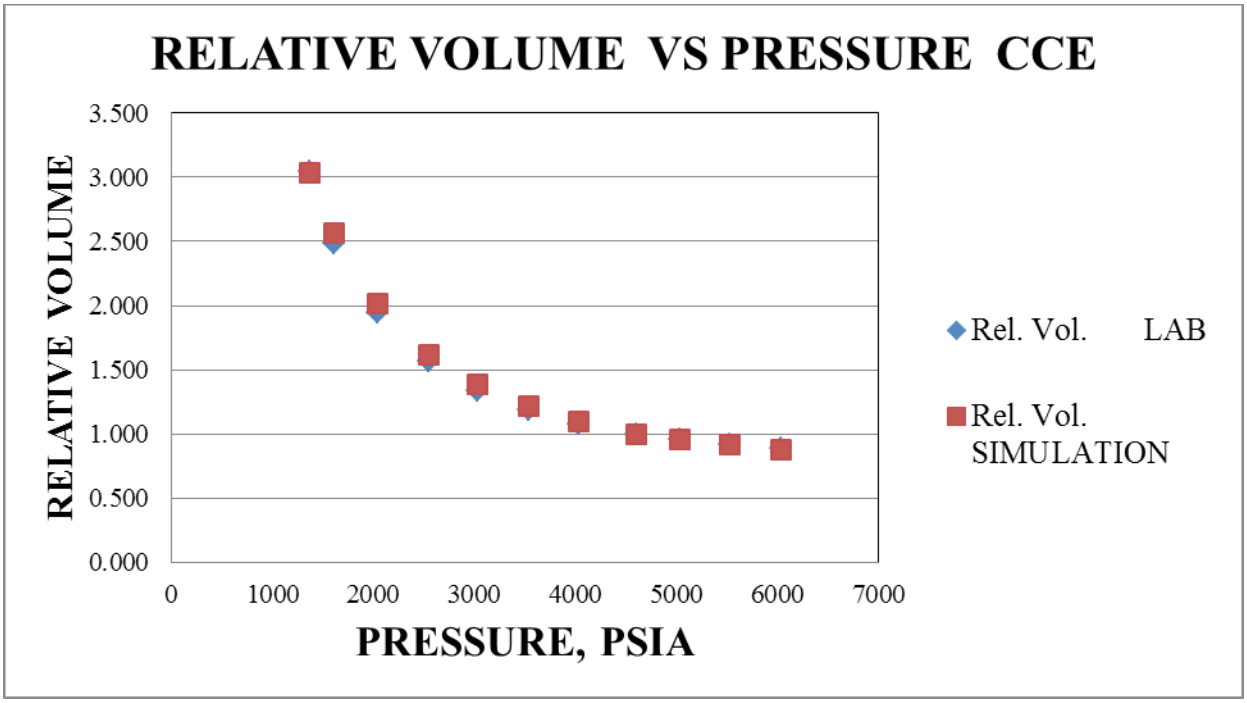

Figure RESULTS AND DISCUSSION.8: Experimental and calculated relative volume for CCE @192.3oF

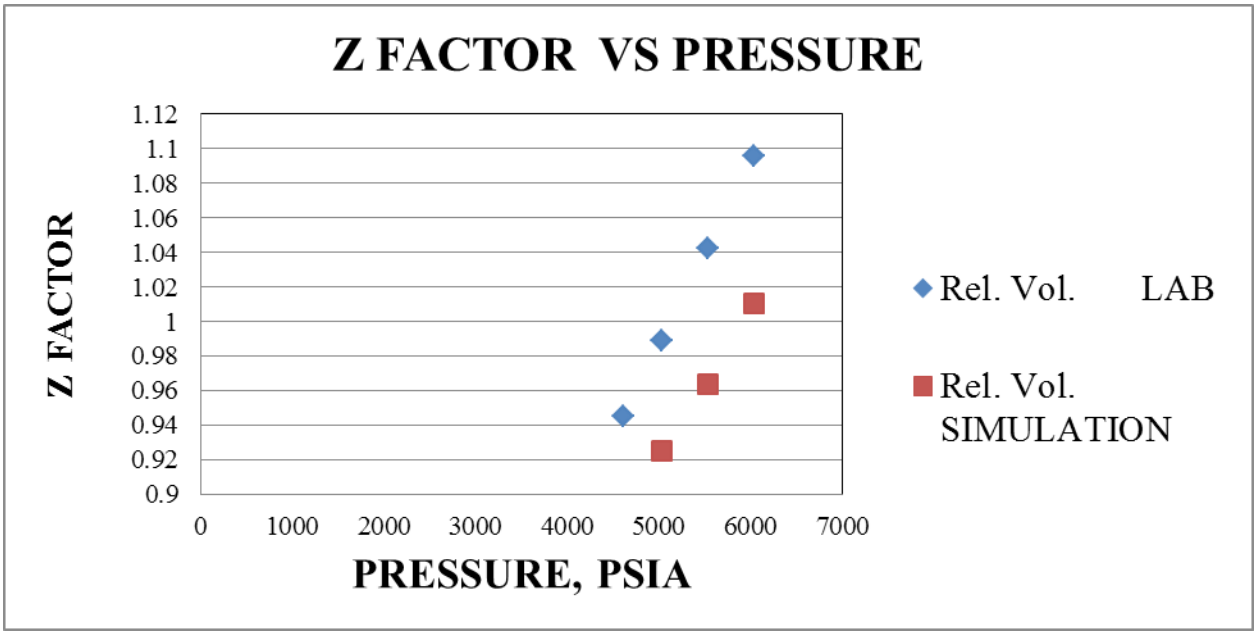

Figure RESULTS AND DISCUSSION.9: Experimental and calculated gas compressibility factor data for CCE @192.3oF

Table RESULTS AND DISCUSSION.4: Shows the saturation pressure of Equation of State and the laboratory data after matching

13 COMPONENTS		
Temperature	**Saturation Pressure**	**Density**
(deg F)	(Psia)	(g/cc)
192.3	4609.03	0.28028
7 COMPONENTS		
Temperature	**Saturation Pressure**	**Density**
(deg F)	(Psia)	(g/cc)
192.3	4605.97	0.273058

Analysis from Results

There was a close match between the experimental and laboratory data showing the reservoir fluid is a representative of what is in the reservoir.

4.2 Pressure and Fluid Saturation Distribution

The reservoir model was run for fifteen years by adopting two reservoir development techniques, natural depletion and gas cycling. The results were discussed by analyzing the trends in the field pressure and fluid saturation distribution of the field at the beginning, quarterly, half way, third quarterly and end of fifteen years of field production. The results obtained from Layer 1 production using two vertical wells at a gas rate of 40 MSCF/D are presented below. Additional results in Layer 2 and 3 are presented in Appendix B.

4.2.1 Natural Depletion

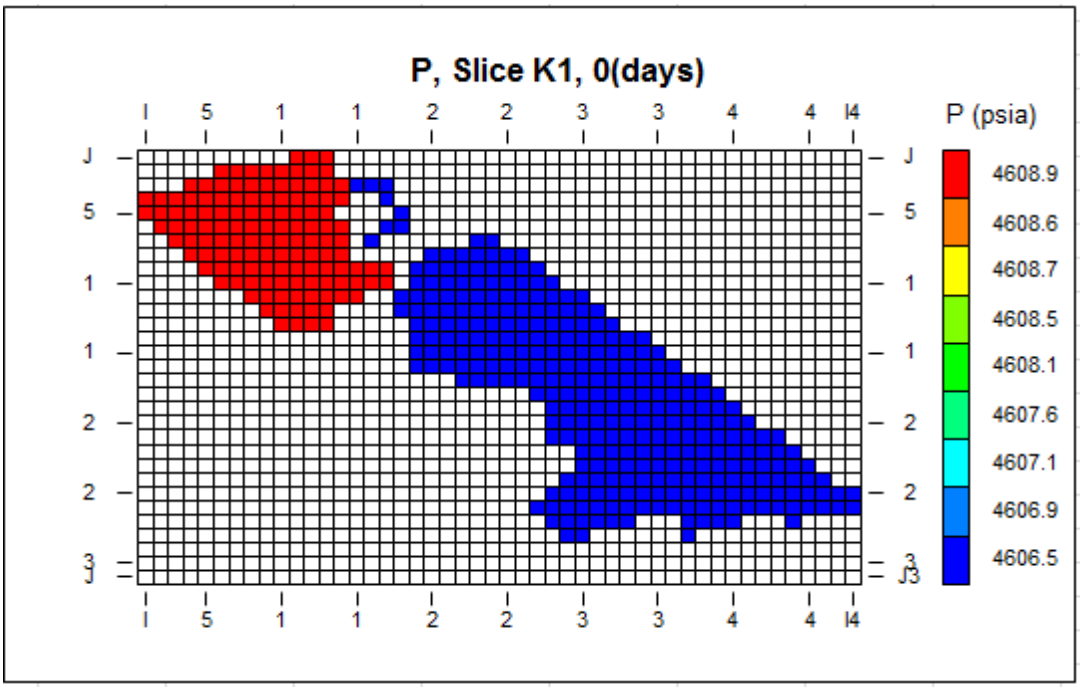

Figure RESULTS AND DISCUSSION.10: Shows Pressure distribution at the beginning of production for the field

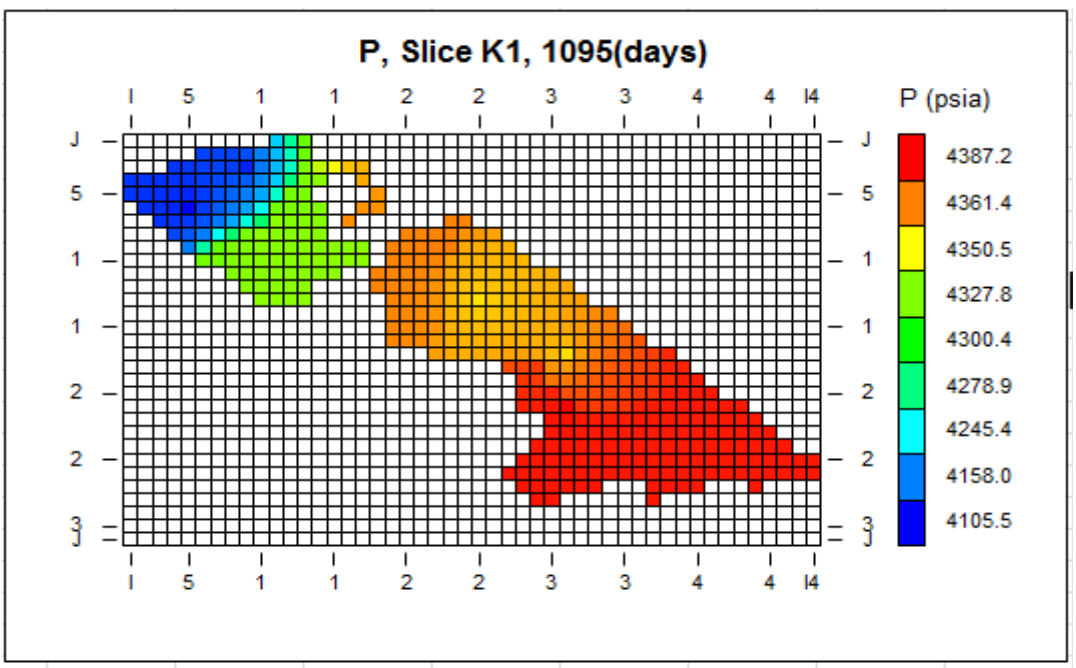

Figure RESULTS AND DISCUSSION.11: Shows quarterly Pressure distribution for the field

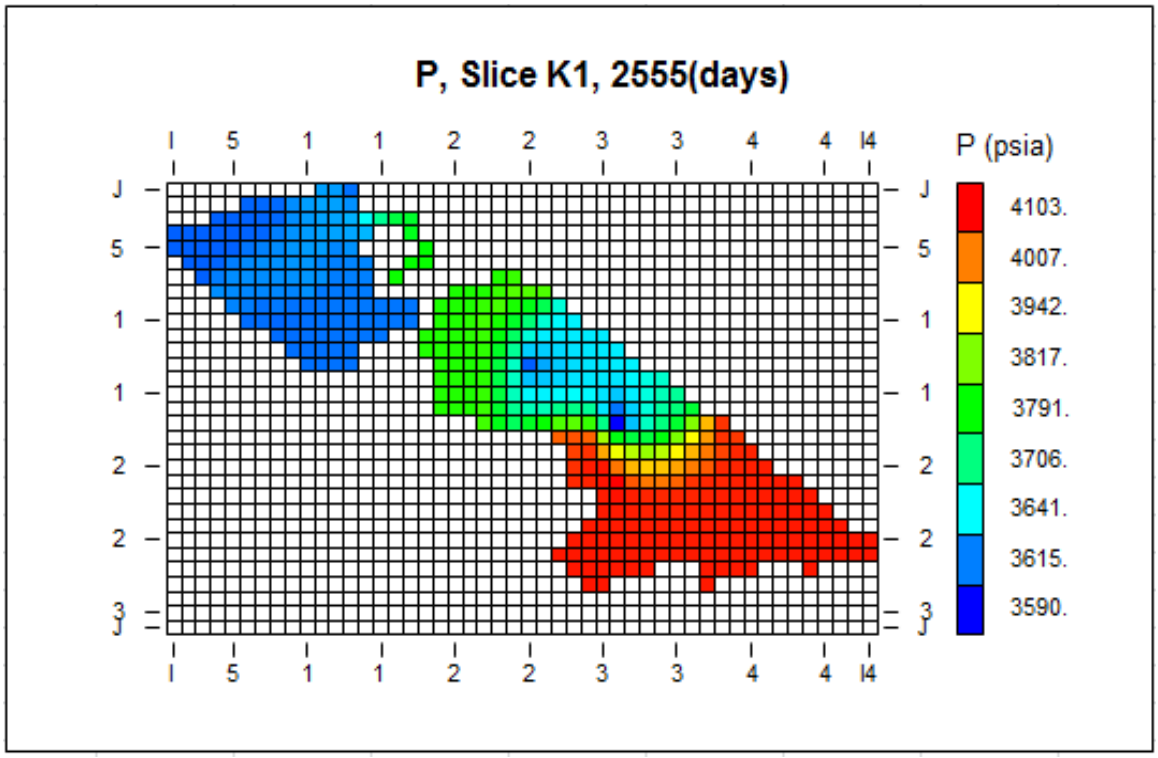

Figure RESULTS AND DISCUSSION.12: Shows mid-way Pressure distribution

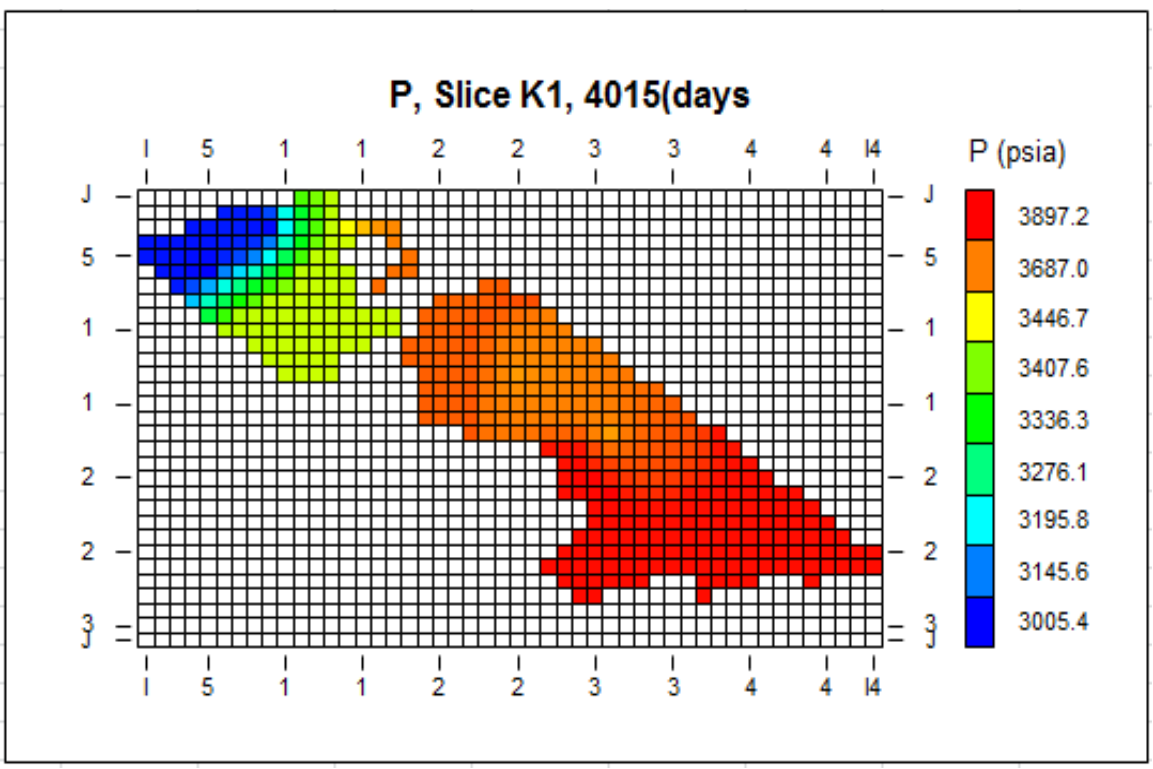

Figure RESULTS AND DISCUSSION.13: Shows Third quarterly Pressure distribution for the field

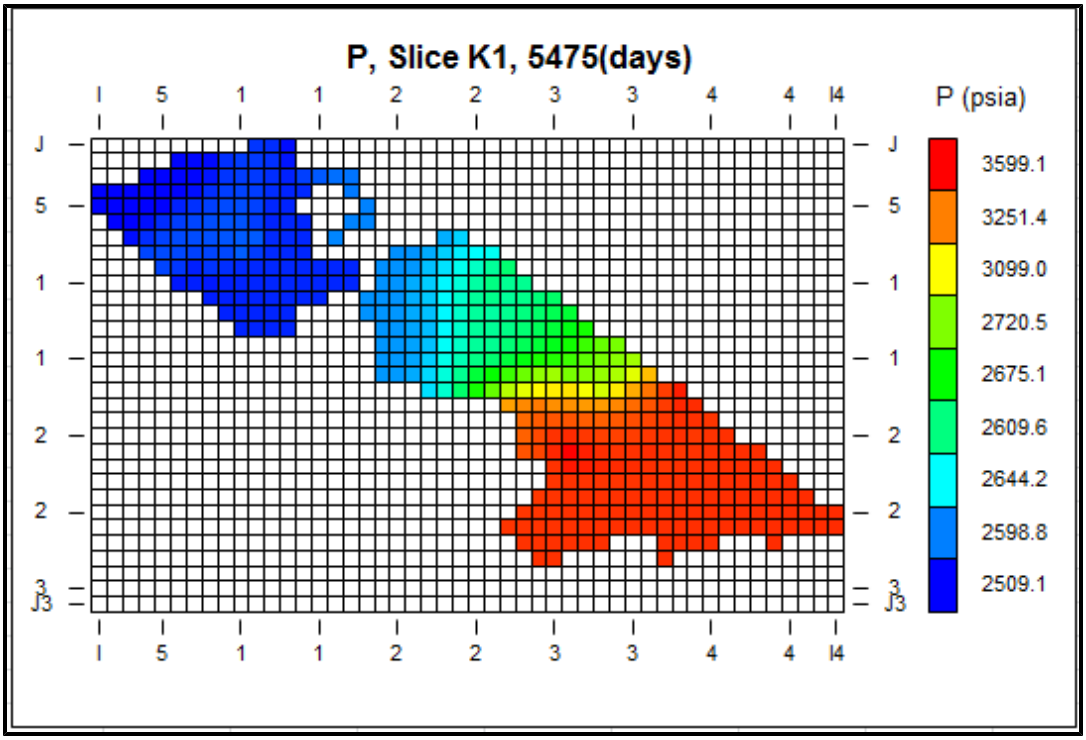

Figure RESULTS AND DISCUSSION.14: Shows Pressure distribution at the end of production

Analysis from Results

The pressure distribution of the field at different times of production, at the beginning, first quarter, mid-way, third quarter and the end of the simulation are presented in Figures 4.6, 4.7, 4.8, 4.9 and 4.10 respectively.

The general trend is that the pressure distribution of the entire field decreases with time. This is associated with fluid withdrawal (gas production). A closer examination of the profile shown in Figure 4.6 depicts that the field is made up of two regions, A (blue color) and B (red color). As production progresses as shown in Figure 4.7, 4.8, 4.9 and 4.10, pressure depletes faster in Region A more than region B, suggesting the possibility of a higher permeability in Region A than region B and also possibly more connectivity of region A with the wells.

Gas Saturation Distribution for Layer 1

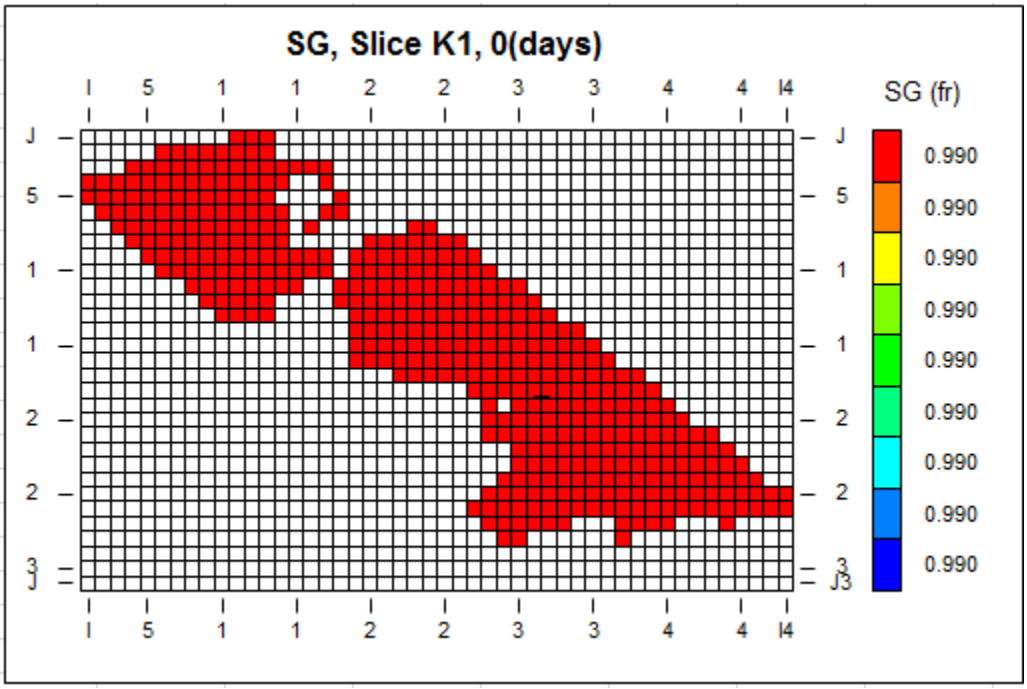

Figure RESULTS AND DISCUSSION.15: Gas saturation distribution at the beginning of production

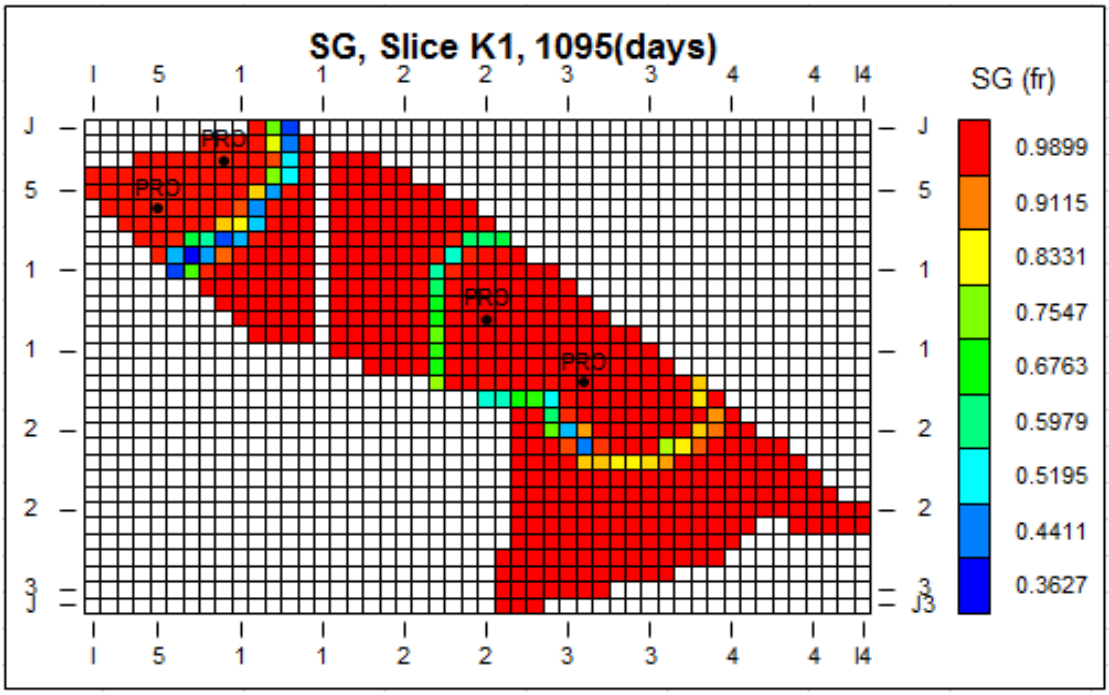

Figure RESULTS AND DISCUSSION.16: Shows quarterly gas saturation distribution during production

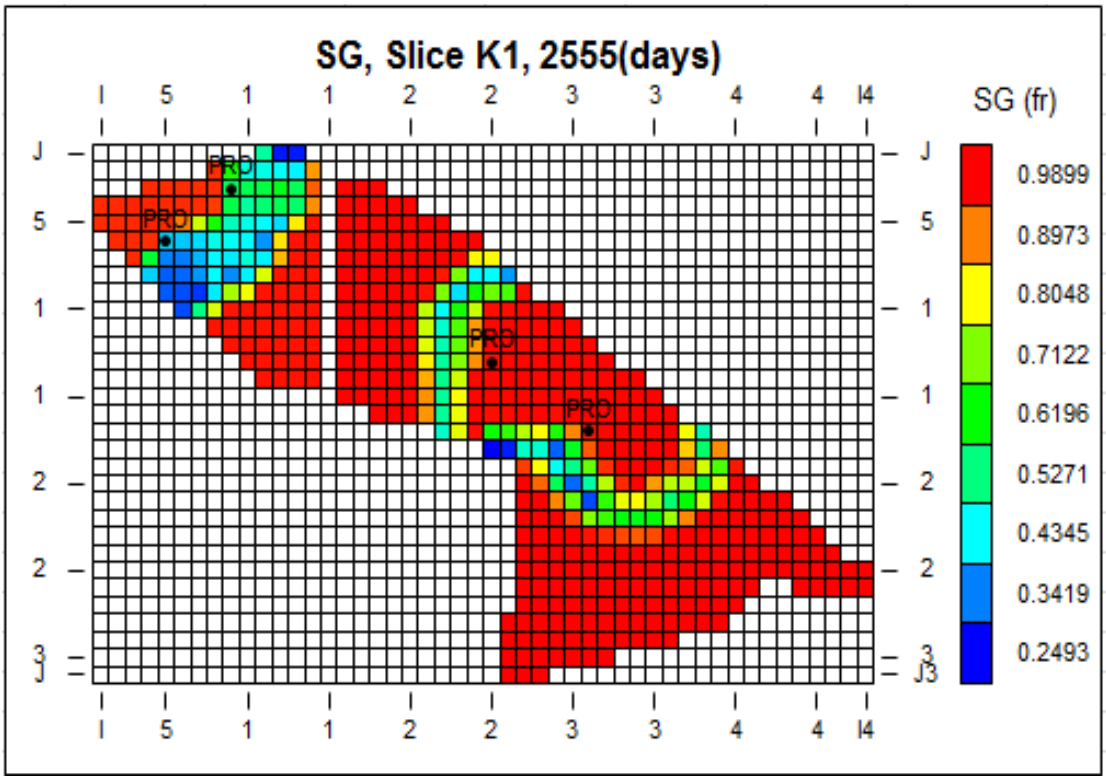

Figure RESULTS AND DISCUSSION.17: Shows Mid-Way Gas Saturation distribution during production//

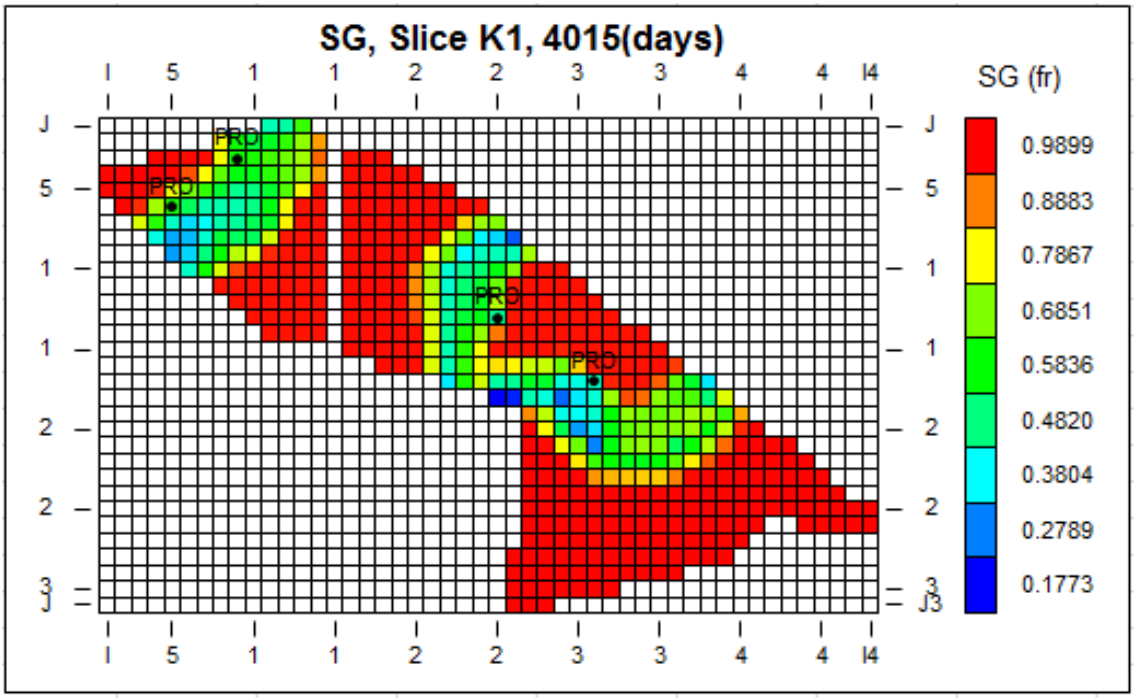

Figure RESULTS AND DISCUSSION.18: Shows Third Quarterly Gas Saturation distribution during production

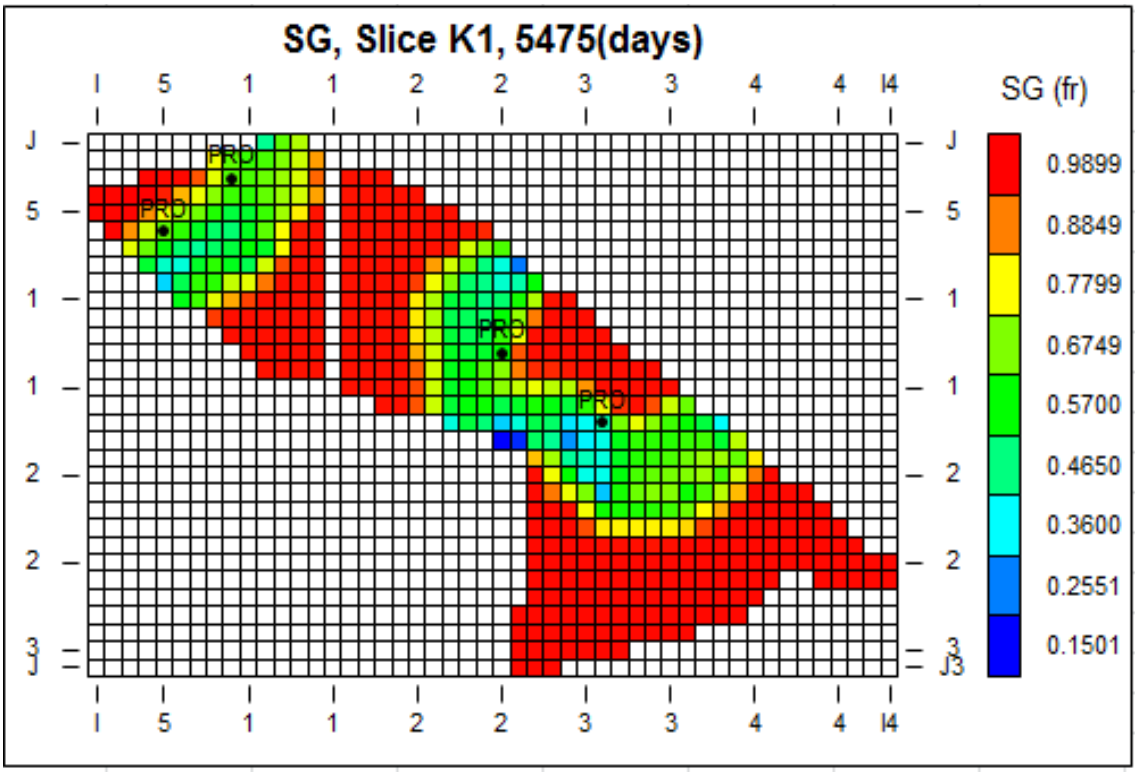

Figure RESULTS AND DISCUSSION.19: Shows Final Gas Saturation distribution during production

Analysis from Results

The gas saturation distribution of the field at different times of production, at the beginning, first quarter, mid-way, third quarter and the end of the simulation are presented in Figures 4.11, 4.12, 4.13, 4.14 and 4.15 respectively.

At the beginning of production, the observed gas saturation profile (Figure 4.11) was uniform throughout the entire field, having 100% relative to the maximum gas saturation. This suggests the reservoir is homogeneous.

As production progresses, the gas saturation distribution tends to decrease, grid cells closer to the wellbore had the highest reduction profile and this was due to fluid withdrawal. At the end of 15 years of simulation, grid cells far away from the wellbore appear to be untapped (gas saturation remains constant) suggesting the possibility of no communication with the wellbore. Thus, optimizing well placement may require additional wells in those locations.

OIL SATURATION DISTRIBUTION

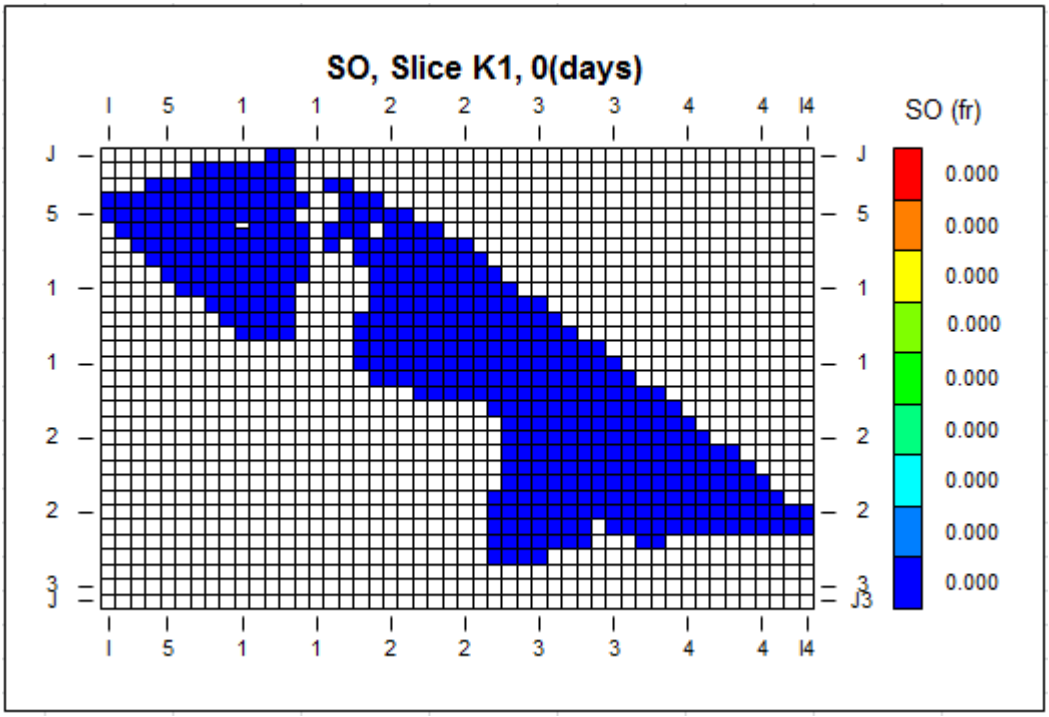

Figure RESULTS AND DISCUSSION.20: Shows Oil Saturation Distribution at the beginning of production

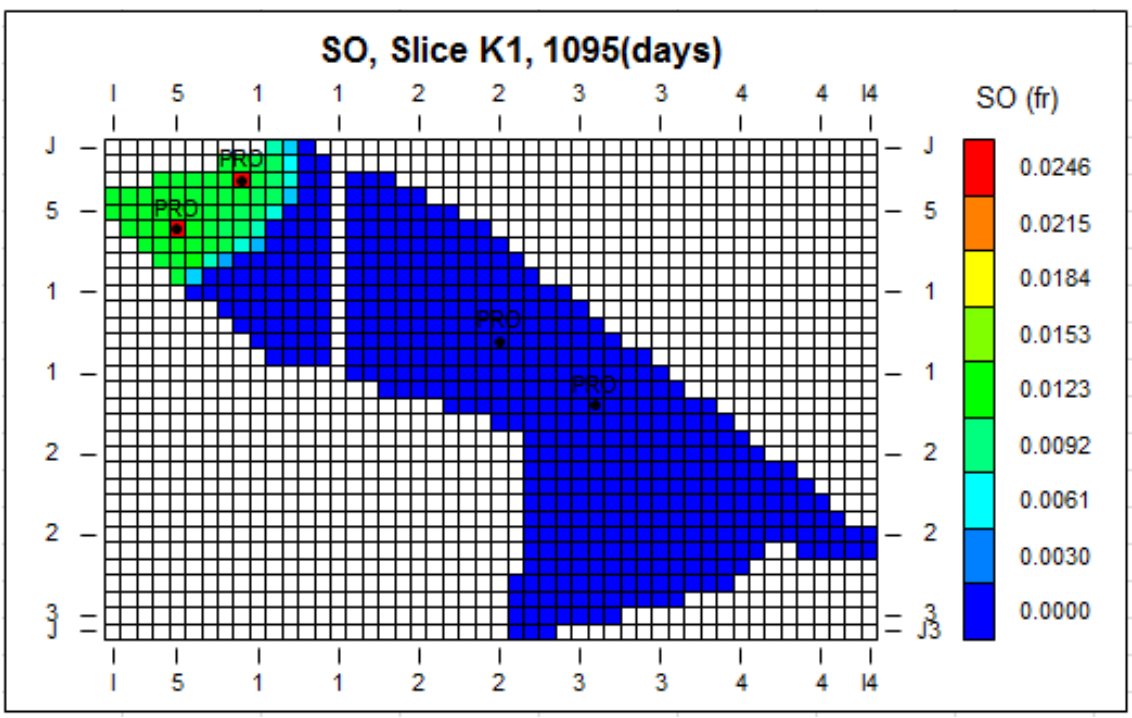

Figure RESULTS AND DISCUSSION.21: Shows Quarterly Oil Saturation during production

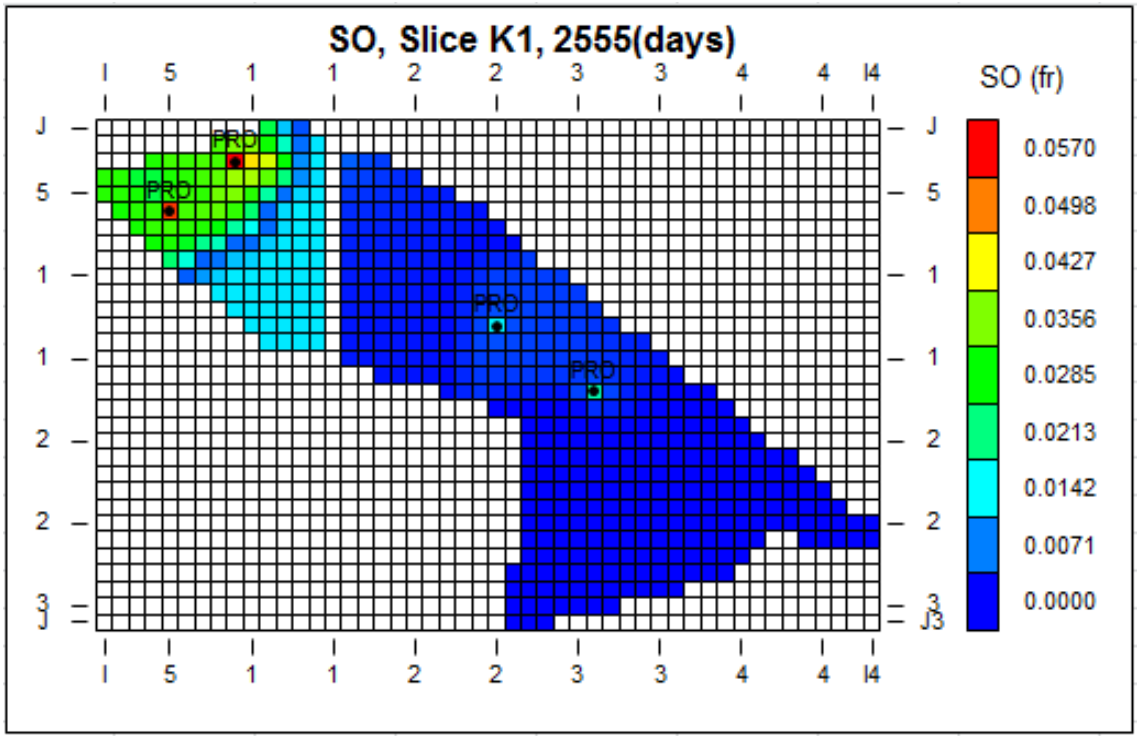

Figure RESULTS AND DISCUSSION.22: Shows Mid-Way Oil Saturation distribution during production

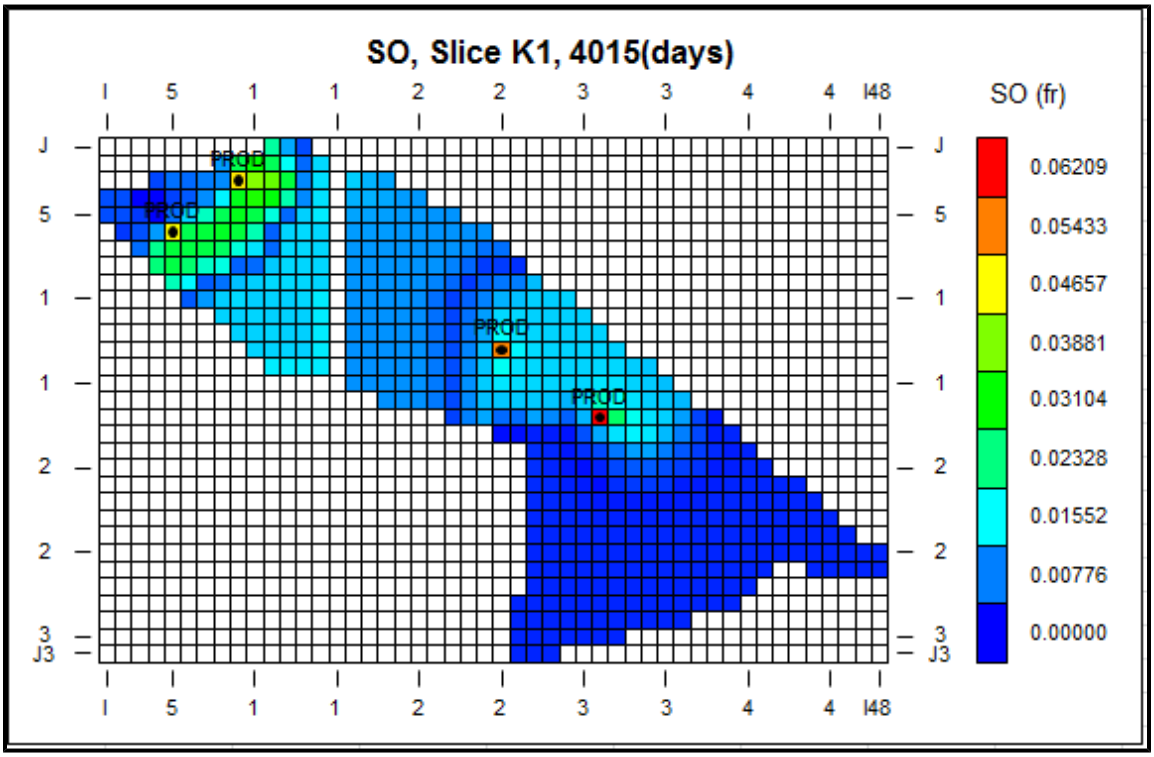

Figure RESULTS AND DISCUSSION.23: Shows Third Quarterly Oil Saturation distribution during production

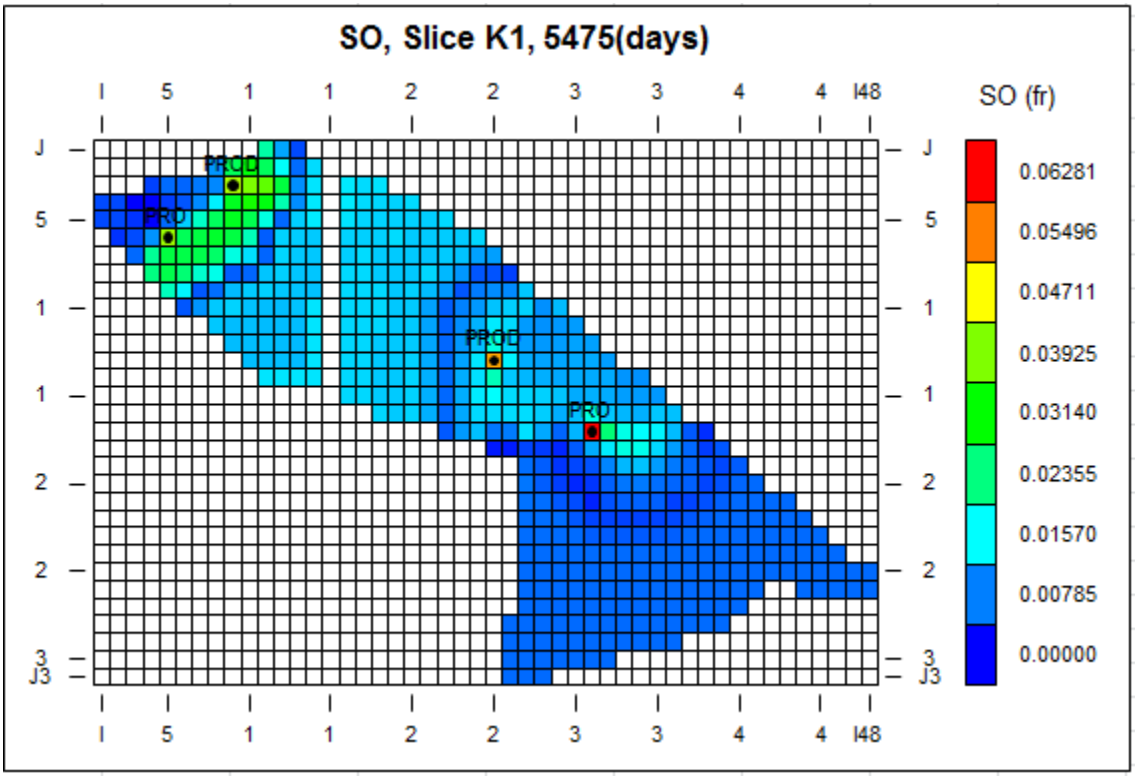

Figure RESULTS AND DISCUSSION.24: Shows final quarterly oil saturation distribution during production

Analysis from Results

The oil saturation distribution of the field at different times of production, at the beginning, first quarter, mid-way, third quarter and the end of the simulation are presented in Figures 4.16, 4.17, 4.18, 4.19 and 4.20 respectively.

At the beginning of production, the oil saturation in the entire field was zero since the reservoir pressure was the same as the dew point pressure. As production progresses, the reservoir pressure decreases below the dew point pressure as a result of fluid withdrawal. This led to liquid dropping out of the gas. The oil saturation progressively increased with the highest increment in the grid cells closer to the wellbore.

4.2.2 Gas Cycling

The produced gas was recycled into the reservoir to maintain the reservoir pressure. The results were discussed by analyzing the trends in the field pressure and fluid saturation distribution for the field at the beginning, quarterly, half way, third quarterly and end of production during gas cycling in layer 1. Additional results in layer 2 and 3 are represented in Appendix B.

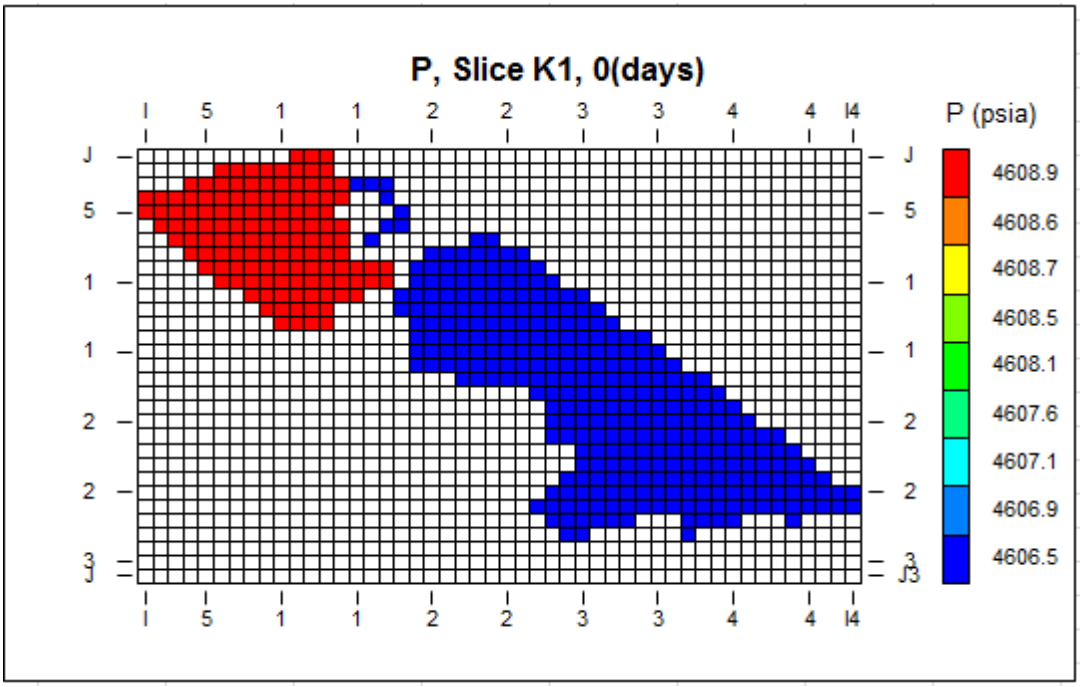

Figure RESULTS AND DISCUSSION.25: Shows Pressure distribution at the beginning of production during gas cycling

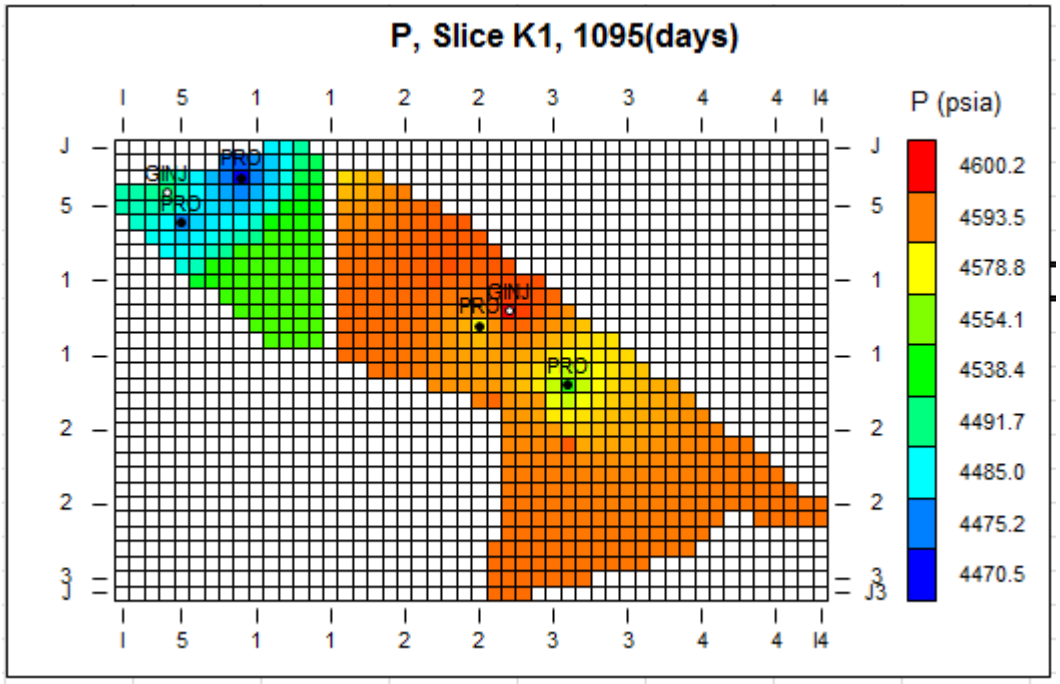

Figure RESULTS AND DISCUSSION.26: Shows Quarterly Pressure distribution

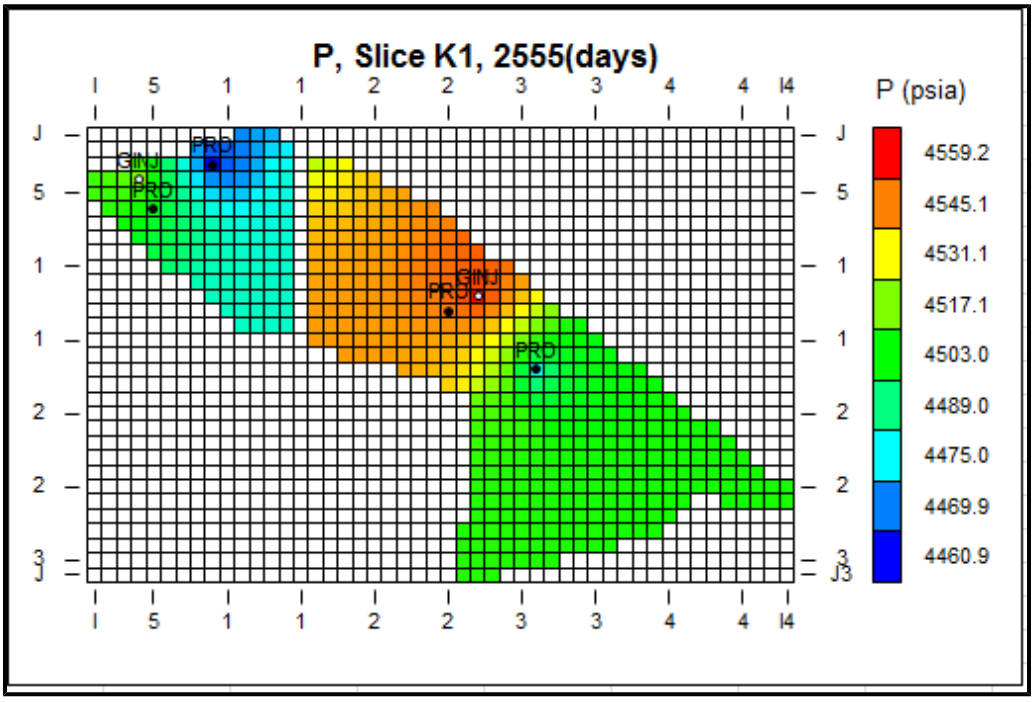

Figure RESULTS AND DISCUSSION.27: Shows Mid-way Pressure distribution during production

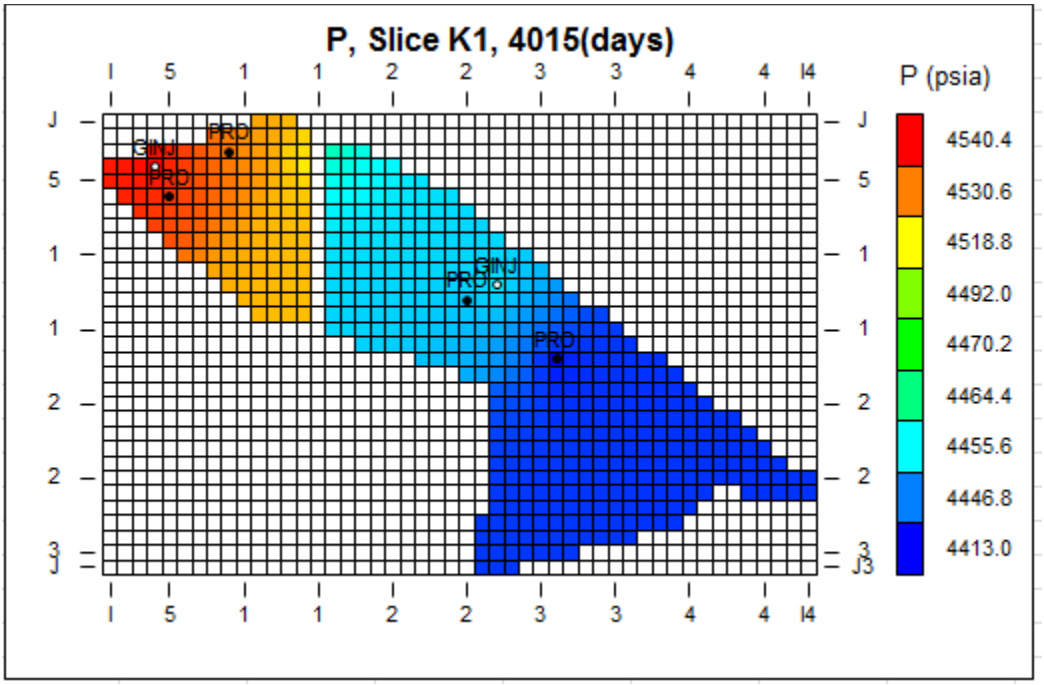

Figure RESULTS AND DISCUSSION.28: Shows Third Quarterly Pressure distribution during production

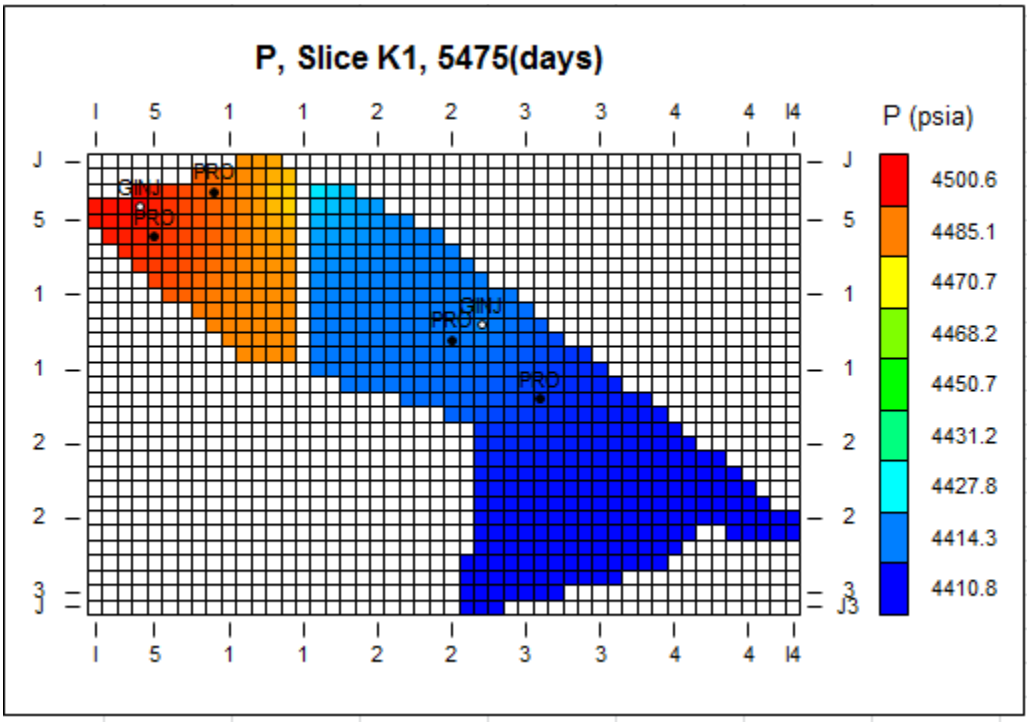

Figure RESULTS AND DISCUSSION.29: Shows Pressure distribution at the end of production

Analysis from Results

The pressure distribution of the field at different times of production during gas cycling, at the beginning, first quarter, mid-way, third quarter and at the end of the simulation are presented in Figures 4.21, 4.22, 4.23, 4.24 and 4.25 respectively.

As production progresses, the pressure distribution decreases slightly compared to the natural depletion production scheme due to the reinjection of the produced gas, which is a pressure maintenance technique. The highest pressure profile is seen in grid cells closer to the injector wells.

However, the general trend of the pressure distribution of production during the gas cycling scheme is similar to the natural depletion production scheme.

Gas Saturation Distribution

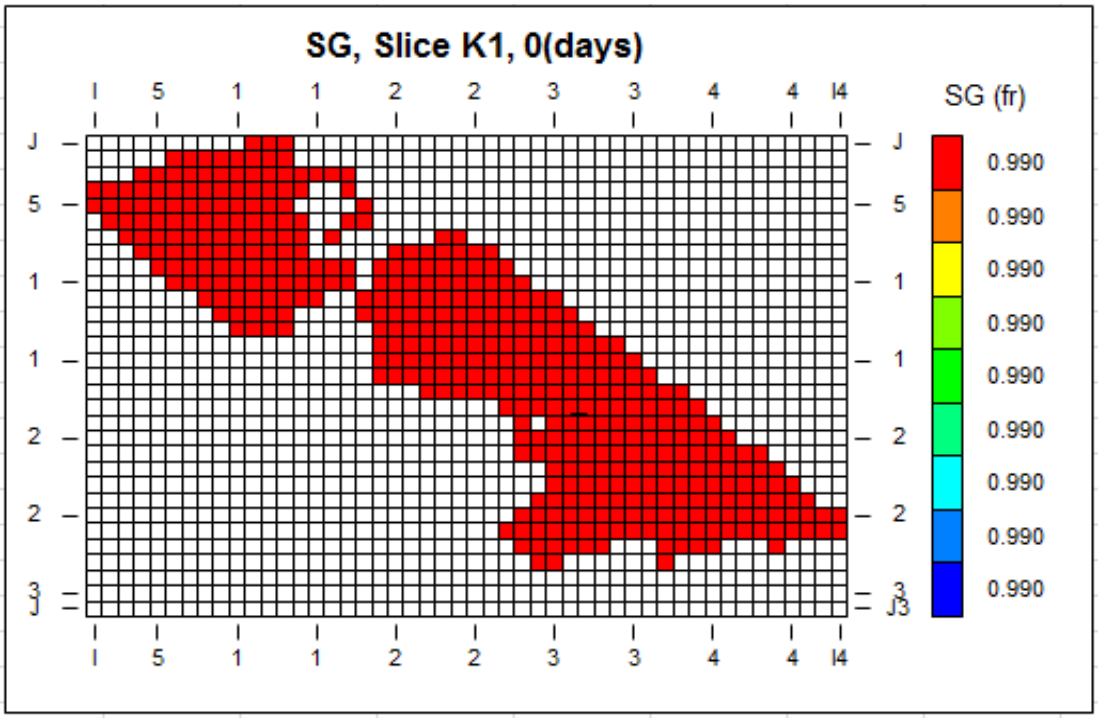

Figure RESULTS AND DISCUSSION.30: Shows Gas Saturation distribution at the beginning of production

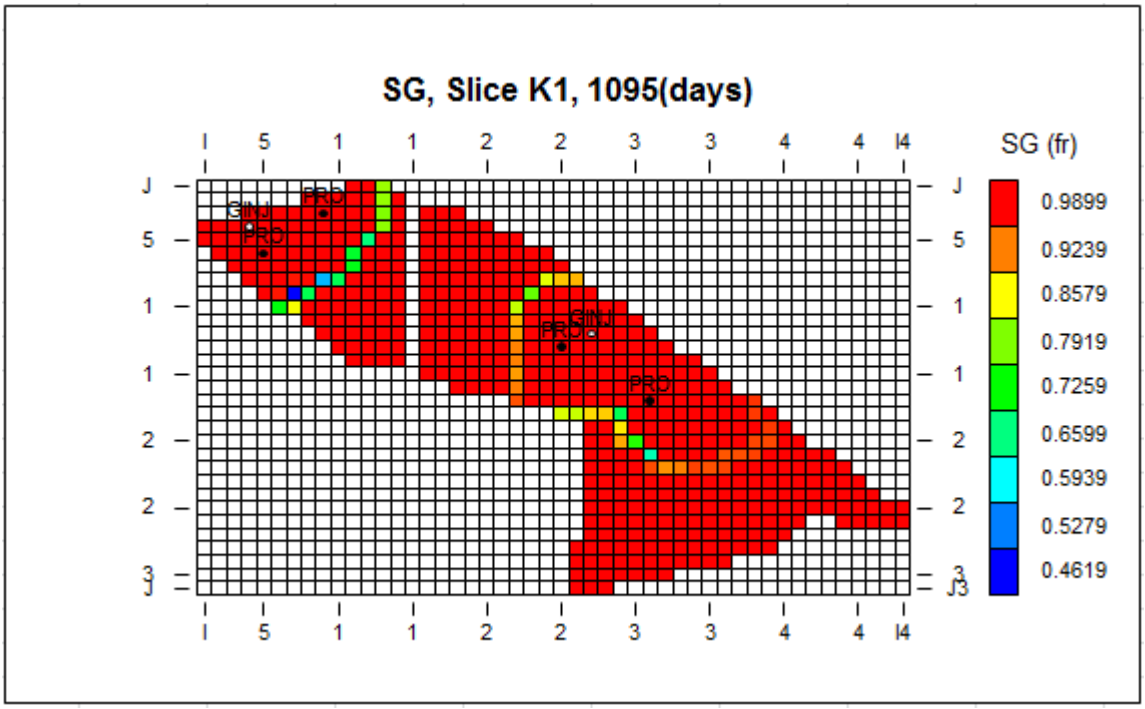

Figure RESULTS AND DISCUSSION.31: Shows Quarterly Gas Saturation distribution during production

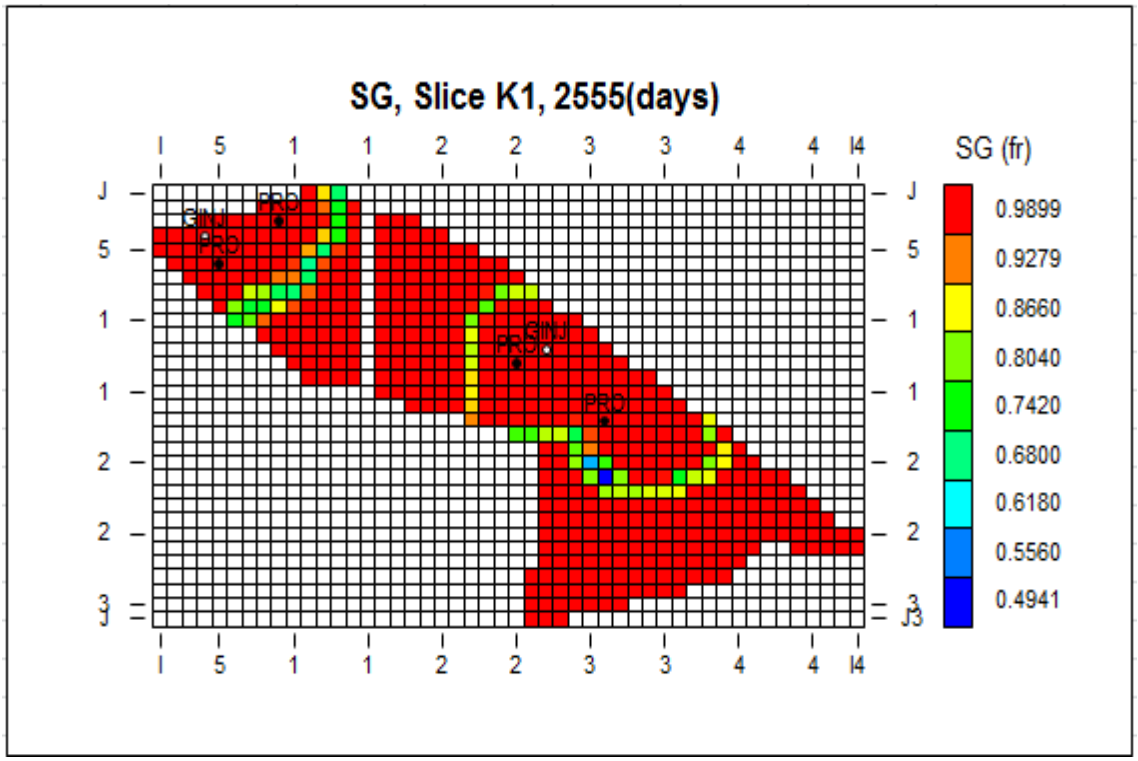

Figure RESULTS AND DISCUSSION.32: Shows Mid-Way Gas Saturation Distribution during production

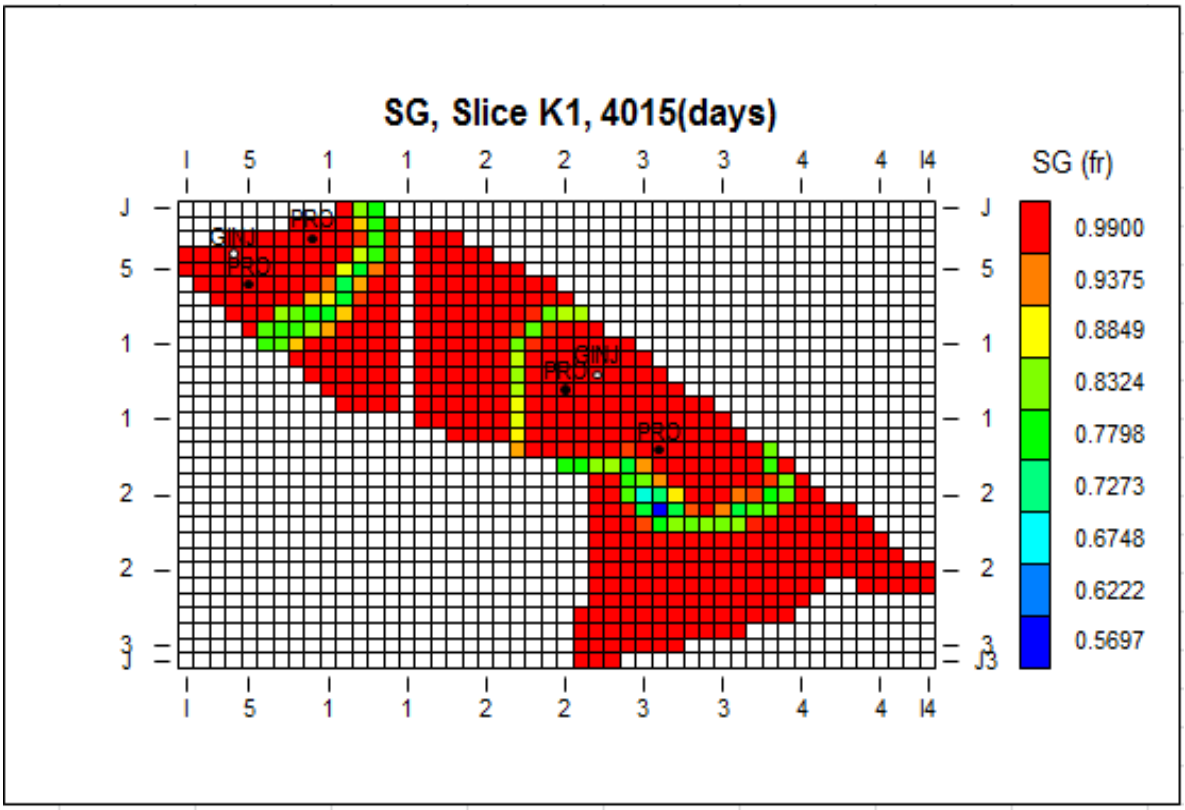

Figure RESULTS AND DISCUSSION.33: Shows Third Quarterly Gas Saturation distribution during production

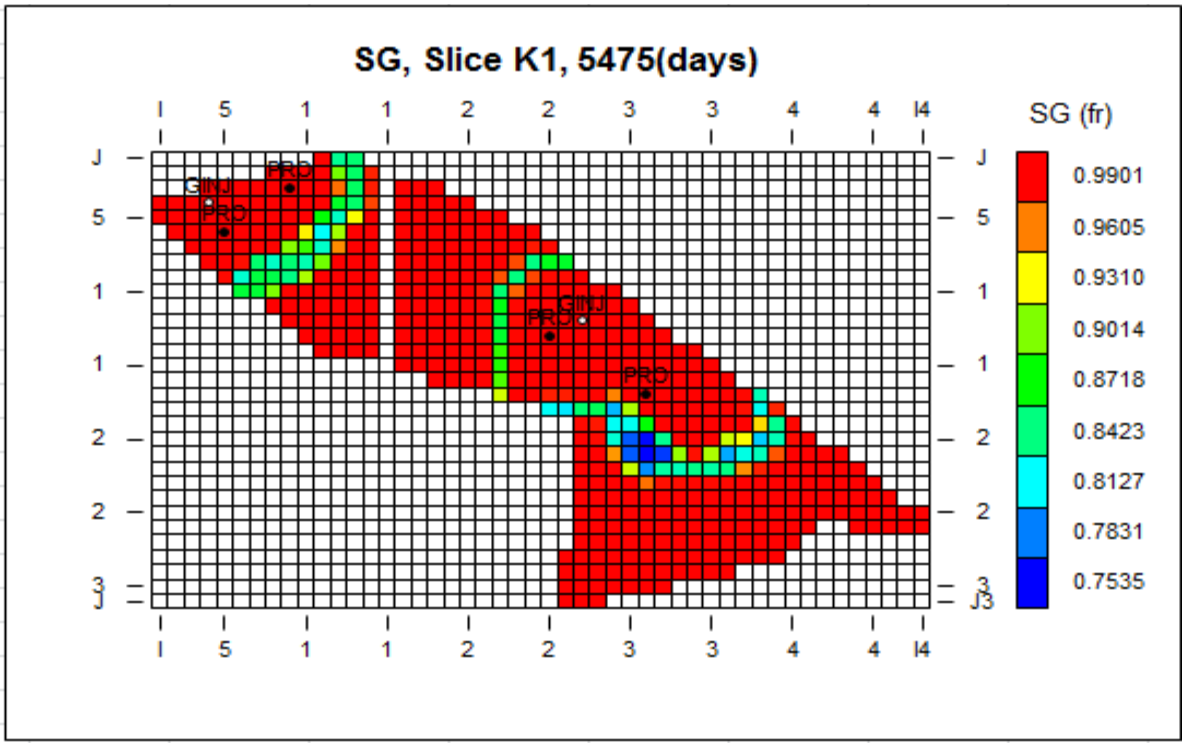

Figure RESULTS AND DISCUSSION.34: Shows Final Gas Saturation Distribution at the end of production

Analysis from Results

The gas saturation distribution of at different times of production during gas cycling, at the beginning, first quarter, mid-way, third quarter and the end of the simulation are presented in Figures 4.26, 4.27, 4.28, 4.29 and 4.30 respectively.

As production progresses, due to re-injection of the produced gas, the gas saturation of the grid cells closer to the wellbore is sustained to almost 100%, relative to the maximum gas saturation. Grid cells farther away from the injector had the least impact of the re-injected gas as shown in Figure 4.27, 4.28, 4.29 and 4.30.

Oil Saturation Distribution

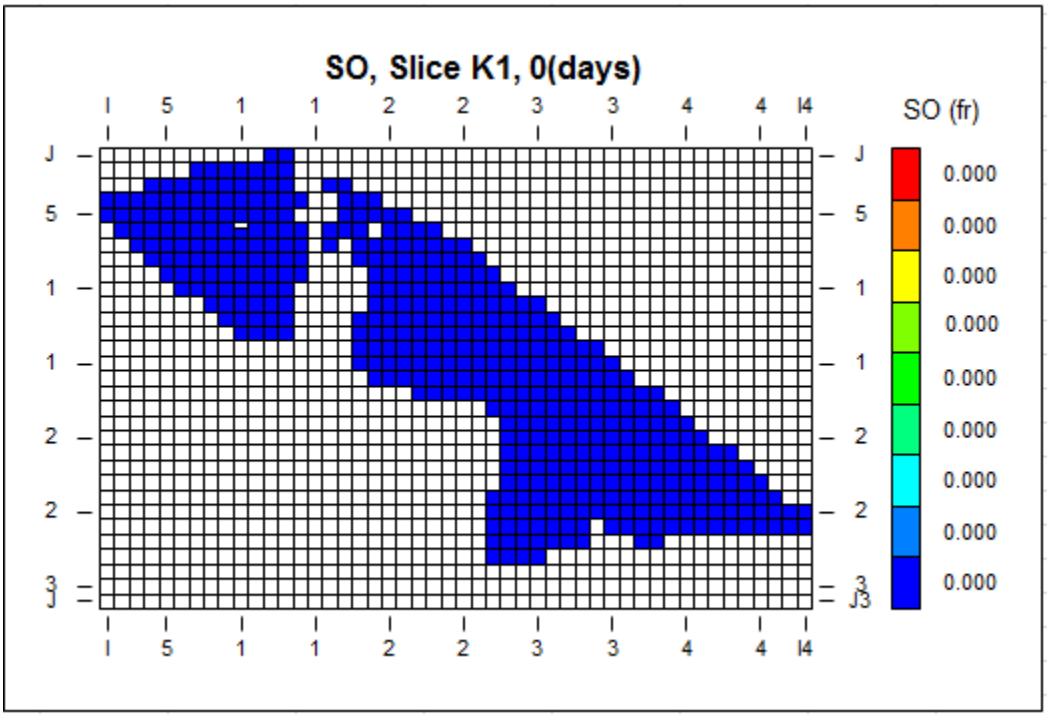

Figure RESULTS AND DISCUSSION.35: Shows Oil Saturation distribution at the beginning of production

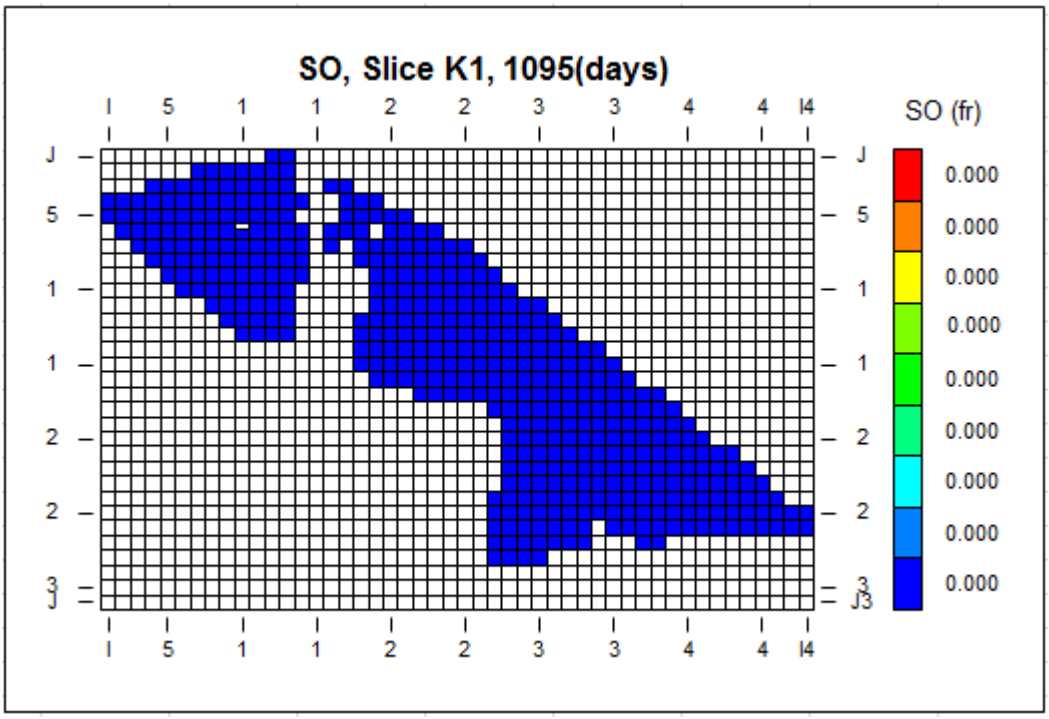

Figure RESULTS AND DISCUSSION.36: Shows Quarterly Oil Saturation distribution during production

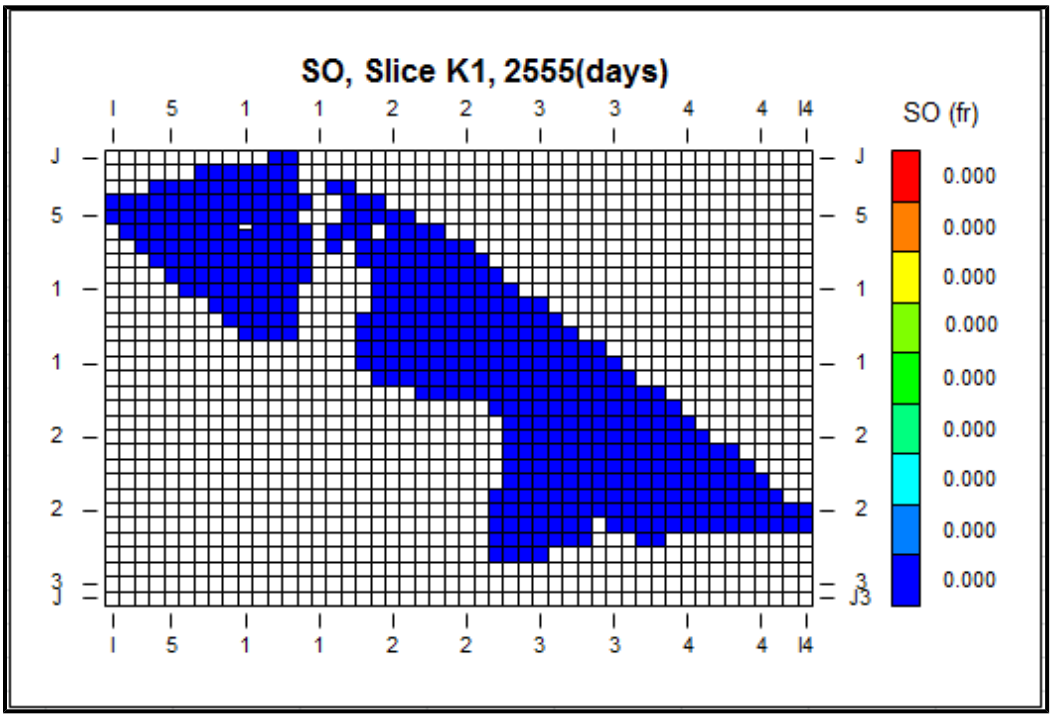

Figure RESULTS AND DISCUSSION.37: Shows Mid-Way Oil Saturation distribution during production

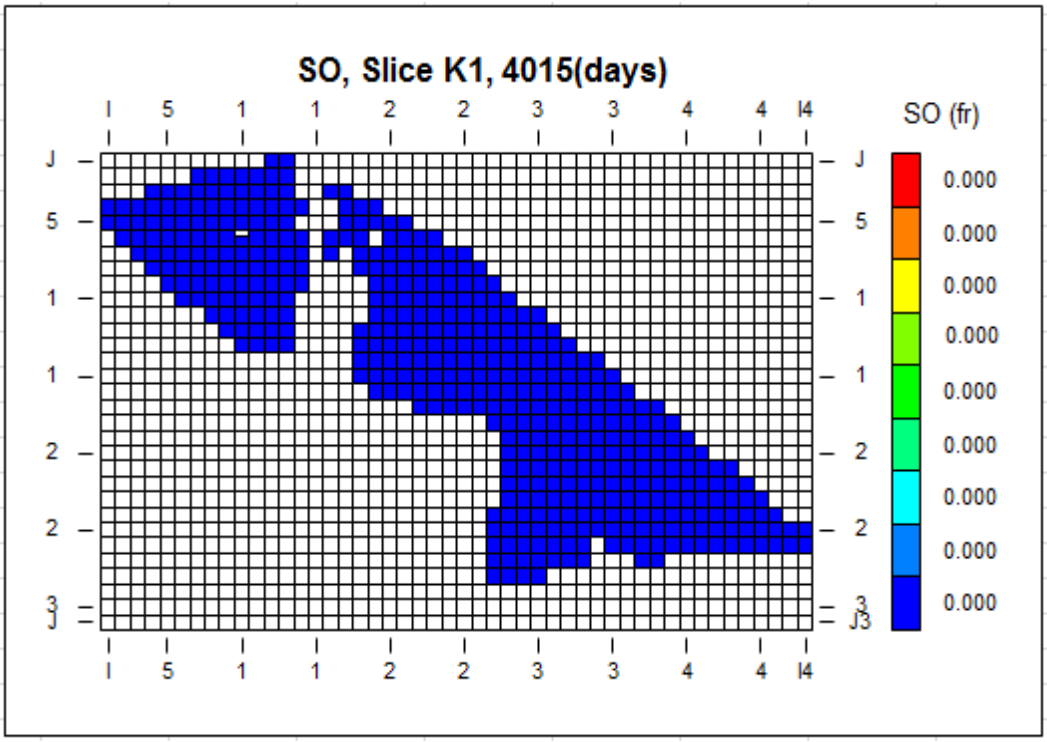

Figure RESULTS AND DISCUSSION.38: Shows Third Quarterly Oil Saturation distribution during production

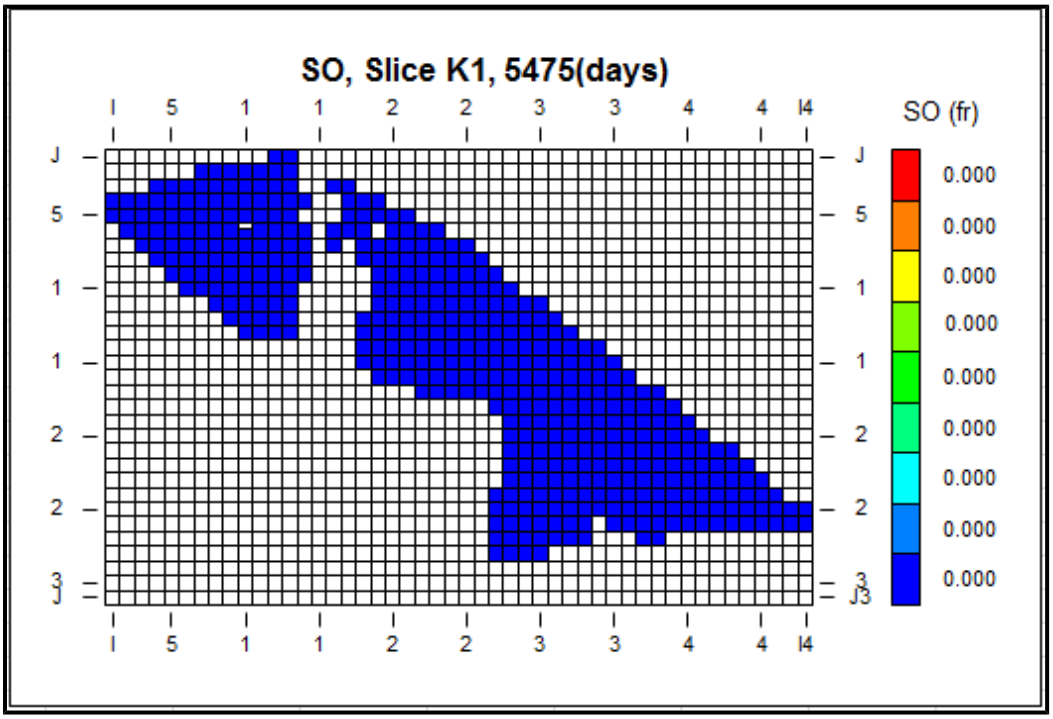

Figure RESULTS AND DISCUSSION.39: Shows Oil Saturation distribution at the end of production

Analysis from Results

The oil saturation distribution of the field at different times of production during gas cycling, at the beginning, first quarter, mid-way, third quarter and the end of the simulation are presented in Figures 4.31, 4.32, 4.33, 4.34 and 4.35 respectively.

The oil saturation distribution profile as shown in Figures 4.31, 4.32, 4.33, 4.34 and 4.35 was zero for all the simulation runs. This is because the gas re-injection, which is a pressure maintenance scheme, was sufficient to prevent the accumulated liquid condensate from being mobile since the resultant reservoir pressure even after fifteen years of simulation, only slightly decreased below the dew point pressure.

4.3 Impact Of Permeability

The simulation was run by using two averaging permeability techniques. Harmonic and geometric average permeability were analyzed using four vertical wells. The results were discussed by analyzing the trends in the field pressure, field total oil production, and gas production. Below Figures are results obtained after the simulation.

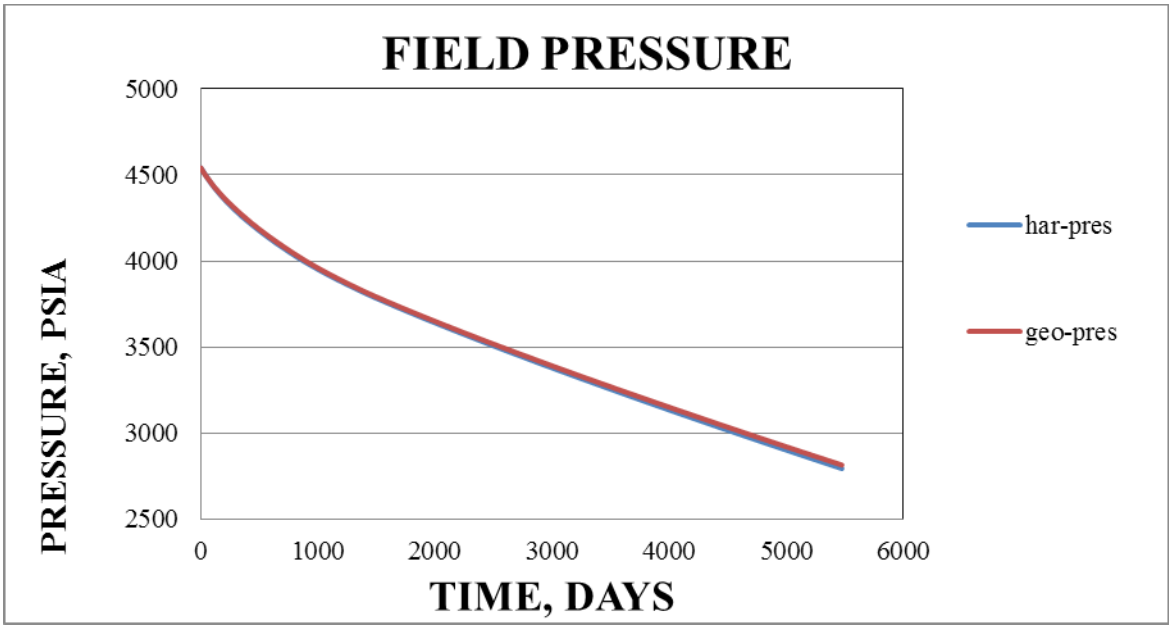

Figure RESULTS AND DISCUSSION.40: Shows Reservoir Pressure of Harmonic and Geometric average permeability

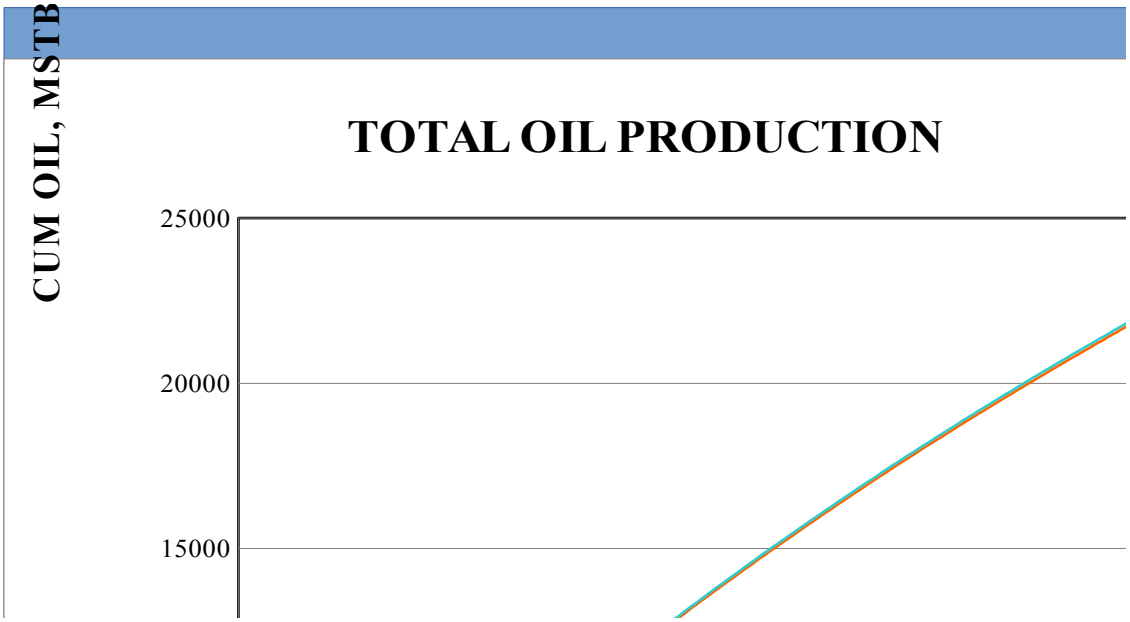

Figure RESULTS AND DISCUSSION.41: Shows The Total Oil Produced at the end of 15 years

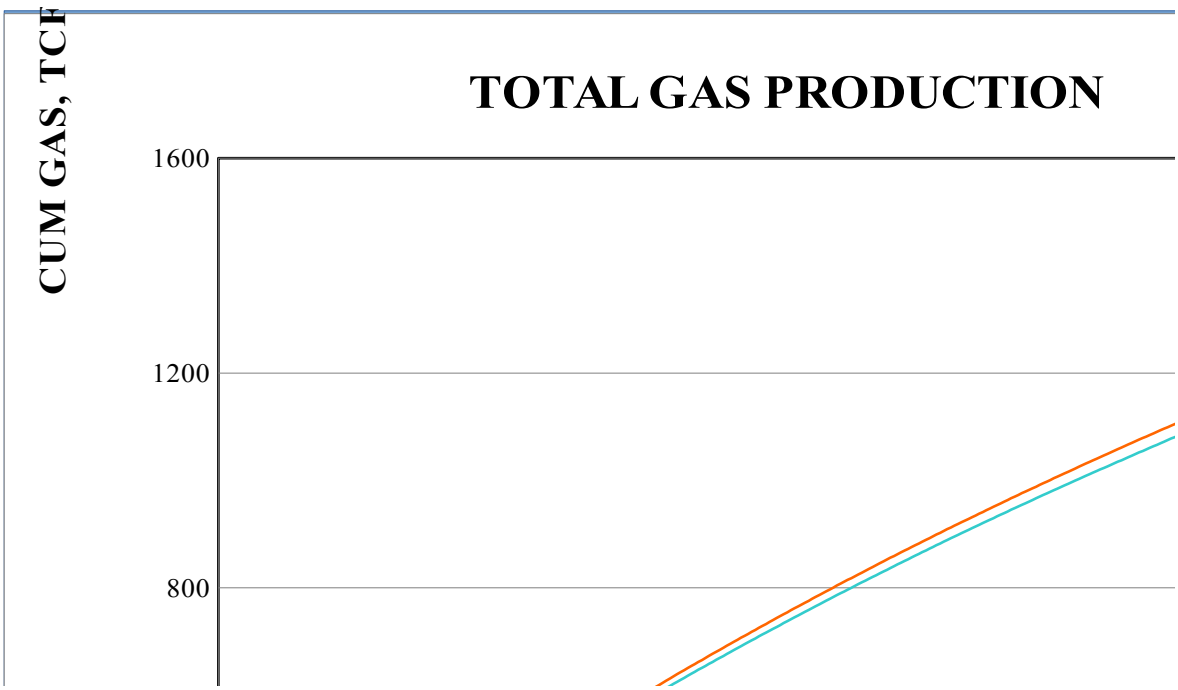

Figure RESULTS AND DISCUSSION.42: Shows the total gas produced at the end of 15year

Analysis from Results

- Relatively the depletion rate was similar for both Harmonic and geometric average permeability.
- Geometric average permeability had the highest condensate production.
- Geometric average permeability had the highest gas production at the end of production.

Geometric averaging permeability gives a higher impact on production than harmonic permeability because it is randomly distributed.

4.4 Field Production

Two scenarios were considered for the field production. Scenario 1 and 2 consist of four horizontal wells and four vertical wells respectively. Each well was set to produce at a gas rate of 40MMCF/D. Natural depletion and pressure maintenance cases were considered for the various scenarios. The results obtained were discussed by analyzing the trends in the field oil production rate, field gas rate, field pressure, field GOR, field total water production, field total oil production and gas production. Scenario 1 and Scenario 2 consist of four horizontal and vertical wells respectively. Also, SC 1 GC and SC 2 GC consist of four horizontal and vertical wells after gas cycling.

The following constraints were set:

- Bottom hole Pressure – 2500 Psia
- Gas Flow Rate – 100 MCF/D per well
- Water cut – 60%

4.4.1 Natural Depletion Case

The various scenarios were analyzed during natural depletion.

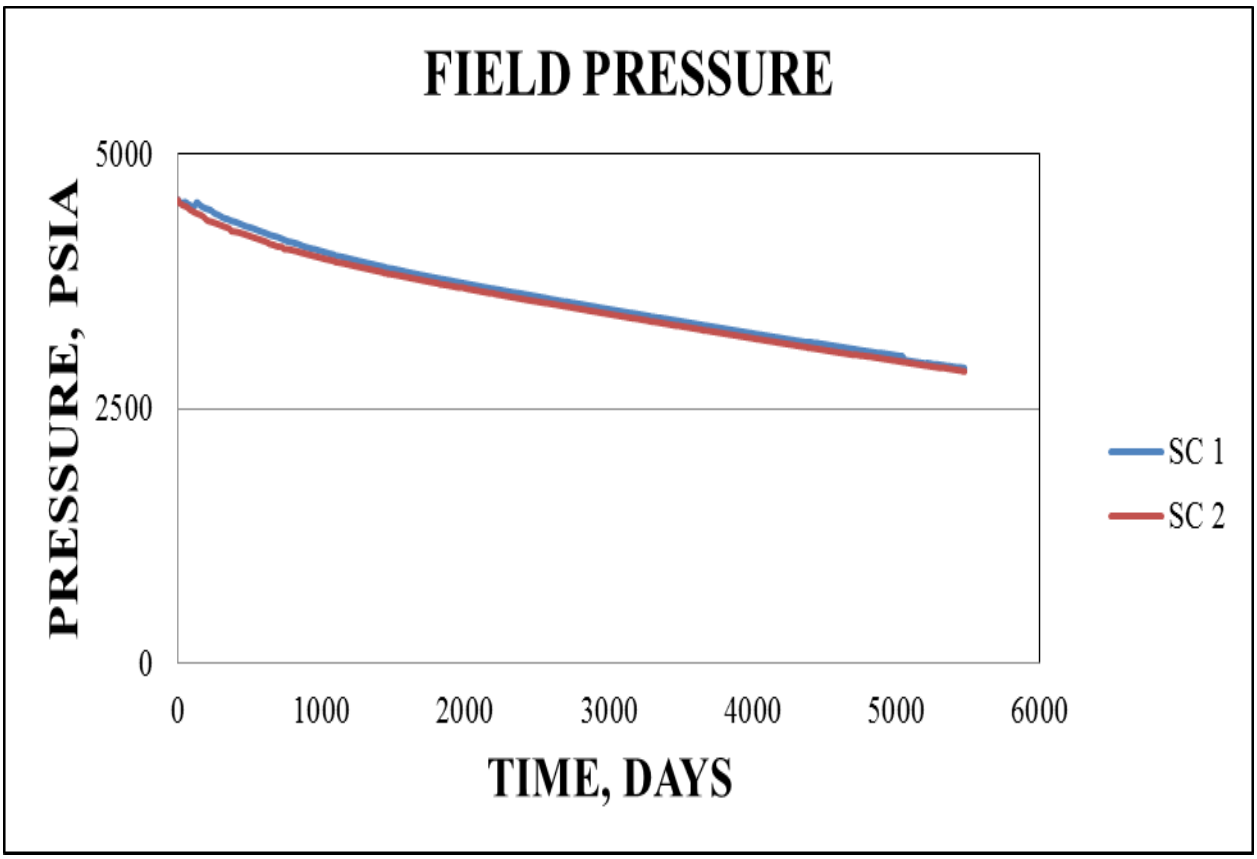

Figure RESULTS AND DISCUSSION.43: Shows the Field Reservoir Pressure

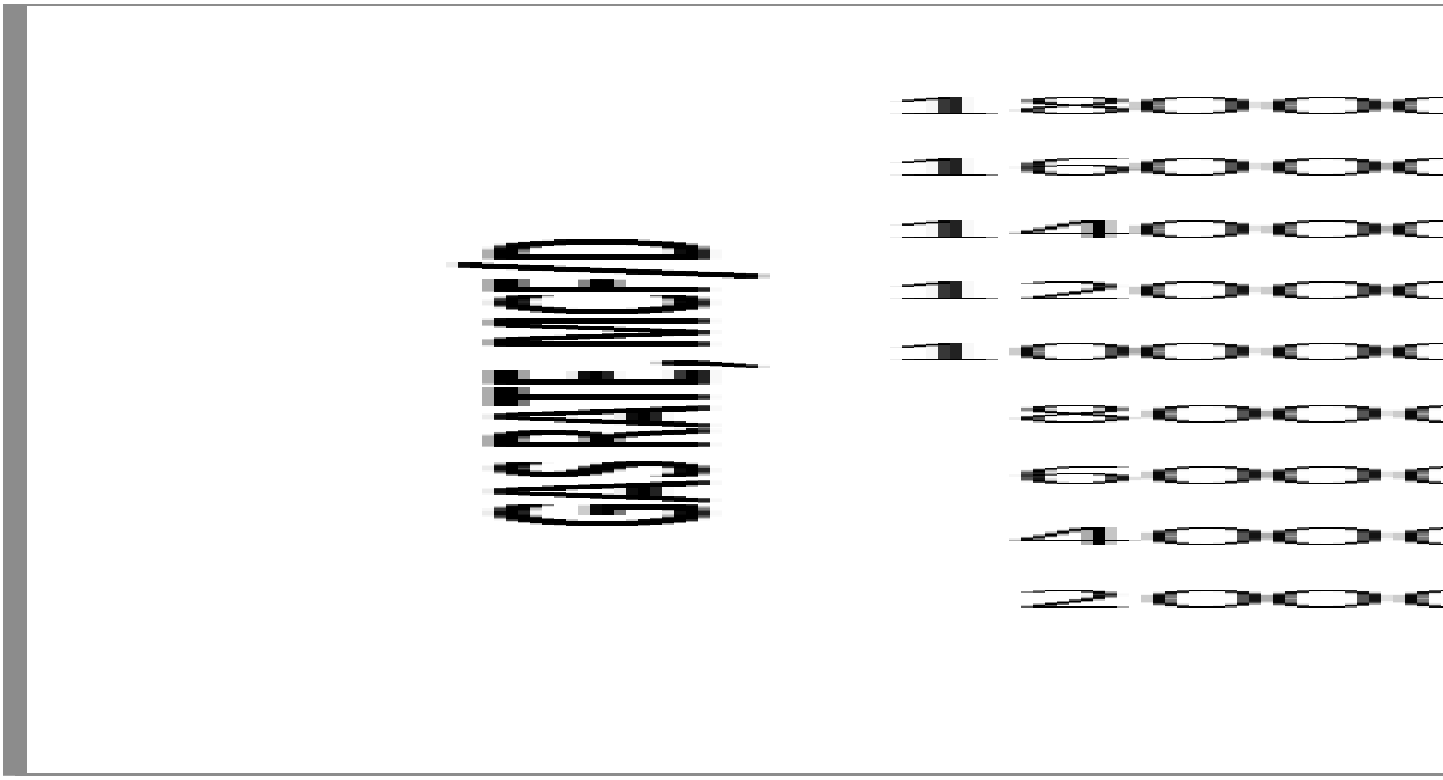

Figure RESULTS AND DISCUSSION.44: Shows the Field Gas and Oil Rate against time

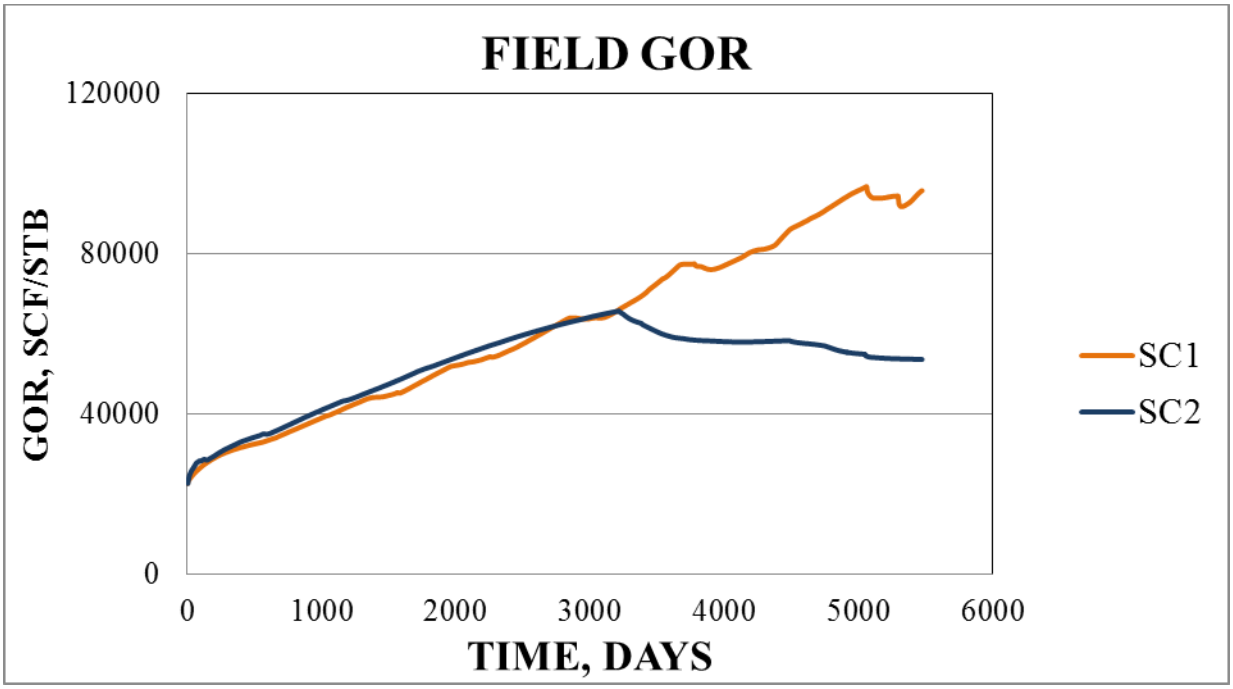

Figure RESULTS AND DISCUSSION.45: Shows the Gas Oil Ratio against time

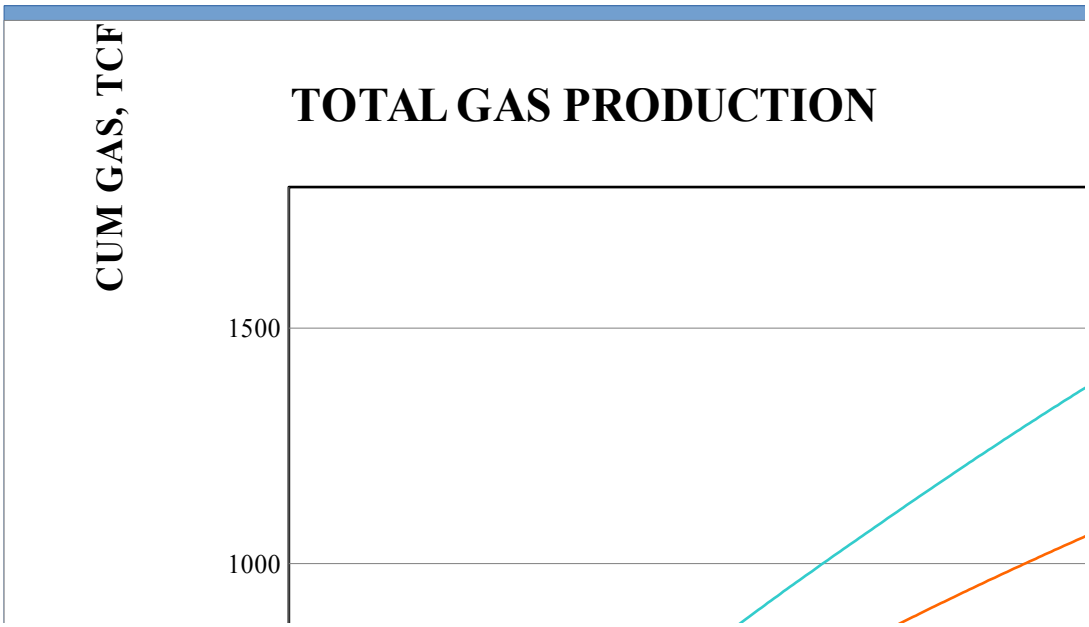

Figure RESULTS AND DISCUSSION.46: Shows the Total Gas production at the end of production

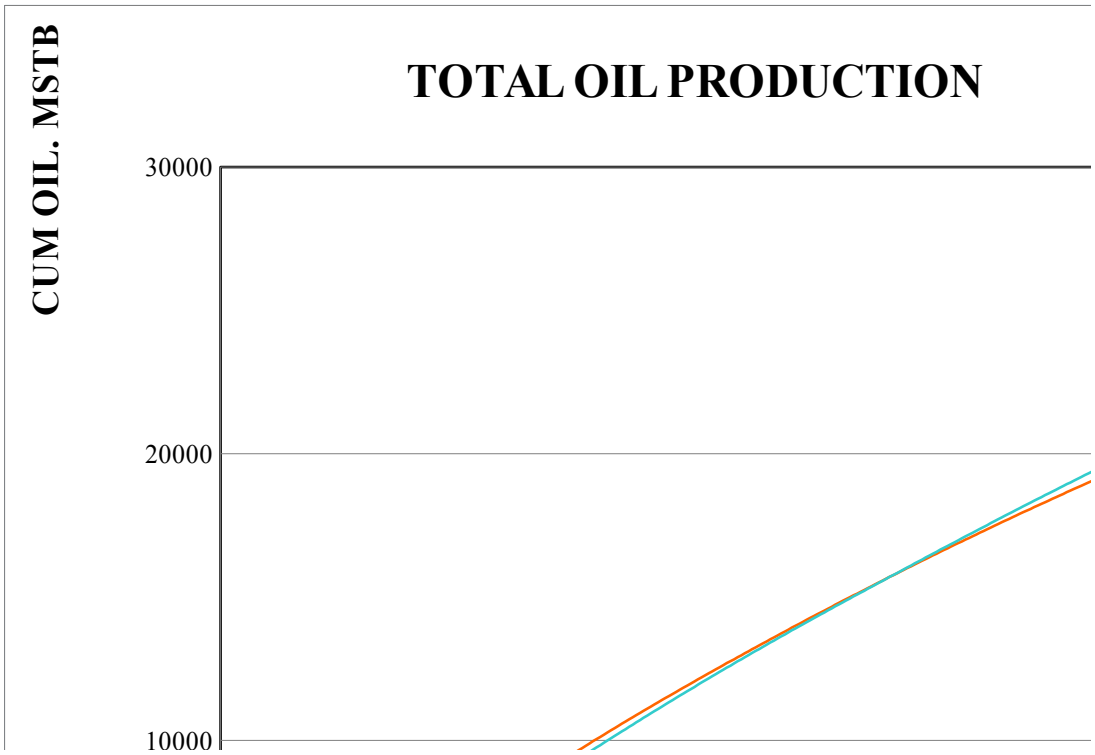

Figure RESULTS AND DISCUSSION.47: Shows the total Oil production at the end of production

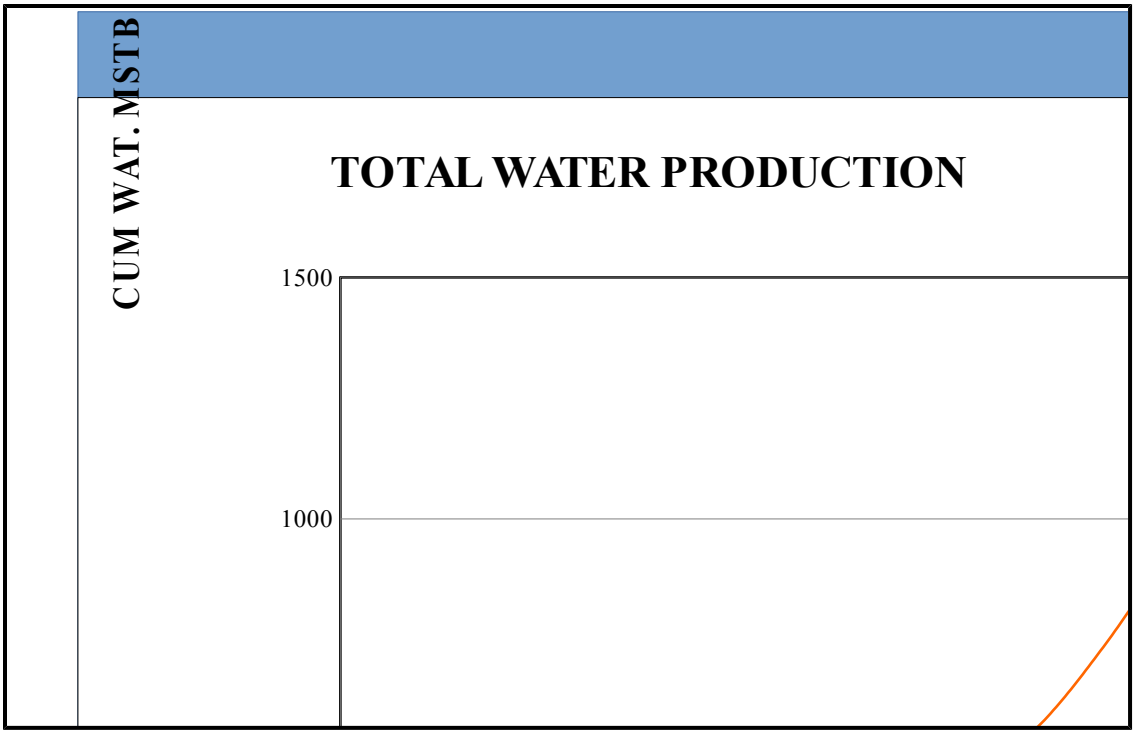

Figure RESULTS AND DISCUSSION.48: Shows the total Water Production at the end of production

Analysis from Results

- Figure 4.39 Reservoir pressure depletes faster with production. Scenario 1 had the lowest reduction in pressure.
- Figure 4.40 Scenario 1 and 2 produced at a plateau with a gas rate of 16 MMCF/D and later started declining. Scenario 2 started declining after 3852 days (10 years) while scenario 1 started declining after 5329 (14 years). Condensate production rate sharply decreased with production time.
- Figure 4.41 Scenario 1 had the highest GOR.
- Figure 4.42 Scenario 1 had the highest cumulative gas production.
- Figure 4.43 Scenario 1 had the highest cumulative oil production.
- Figure 4.44 Scenario 2 had the highest cumulative water production.

Reservoir pressure depletes with production time. As reservoir pressure falls below the dew point, liquid starts dropping out of the gas, this causes the condensate production to sharply decline because it is in the immobile phase. At the immobile phase, the condensate saturation is lower than the critical condensate saturation causing the condensate not to flow towards the wellbore. Condensate becomes mobile when condensate saturation is higher than the critical

condensate saturation. The movement of the condensate leads to a decrease in gas production rate because more liquid is dropping from the gas. The liquid dropout causes an increase in GOR.

Summary

- Reservoir pressure depletes faster in gas condensate reservoirs.
- GOR is continually raised in production time.
- High condensate formation in the reservoir has an adverse effect on gas production rate.
- Horizontal wells have a smaller drawdown.
- Horizontal wells reduce condensate blockage near the wellbore leading to high gas and oil rates.

4.4.2 Gas Cycling

Since the reservoir pressure is the same as the dew point, pressure maintenance was introduced at the beginning of the production. Produced gas was recycled into the reservoir. The results obtained were discussed by analyzing the trends in the field oil production rate, field gas rate, field pressure, field GOR, field total water production, field total oil production and gas production.

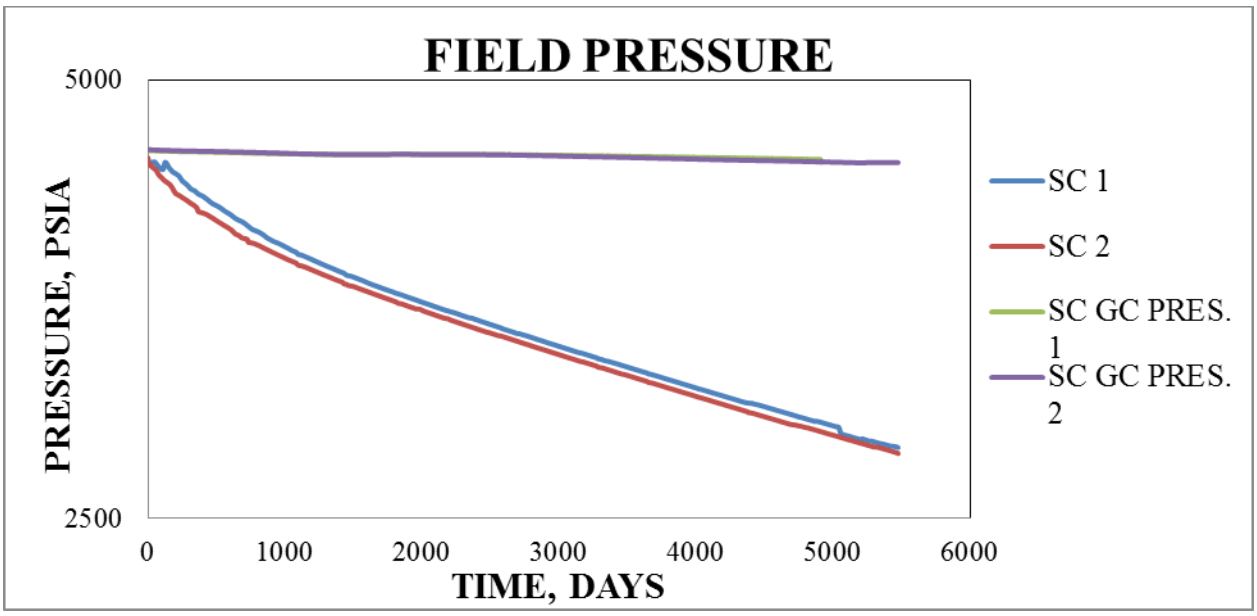

Figure RESULTS AND DISCUSSION.49: Shows The Reservoir Pressure before and after gas cycling

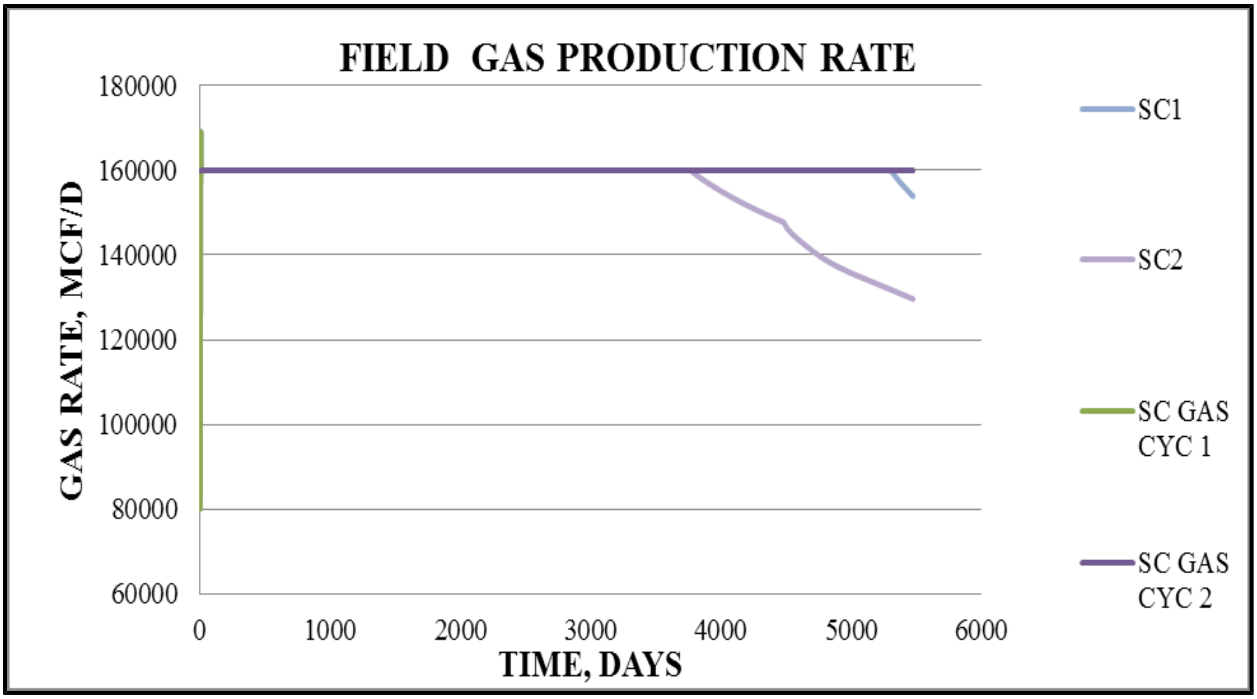

Figure RESULTS AND DISCUSSION.50: Shows the Field gas rate before and after gas cycling

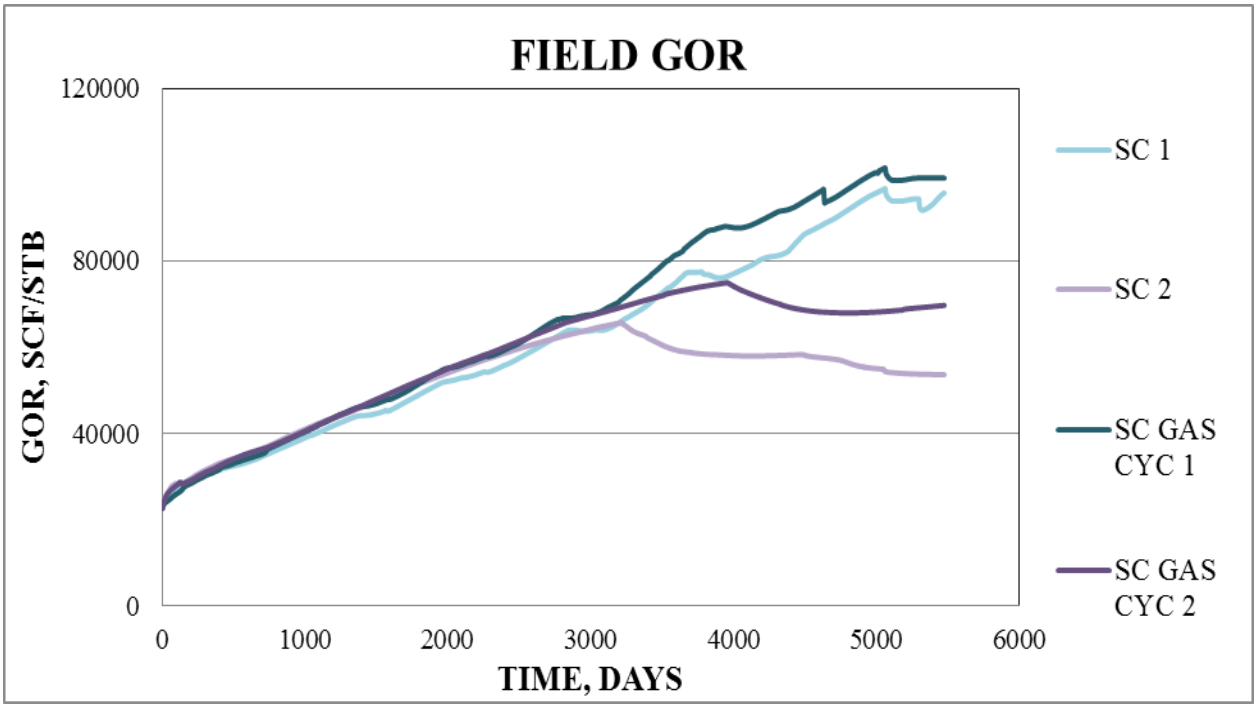

Figure RESULTS AND DISCUSSION.51: Shows the GOR before and after gas cycling

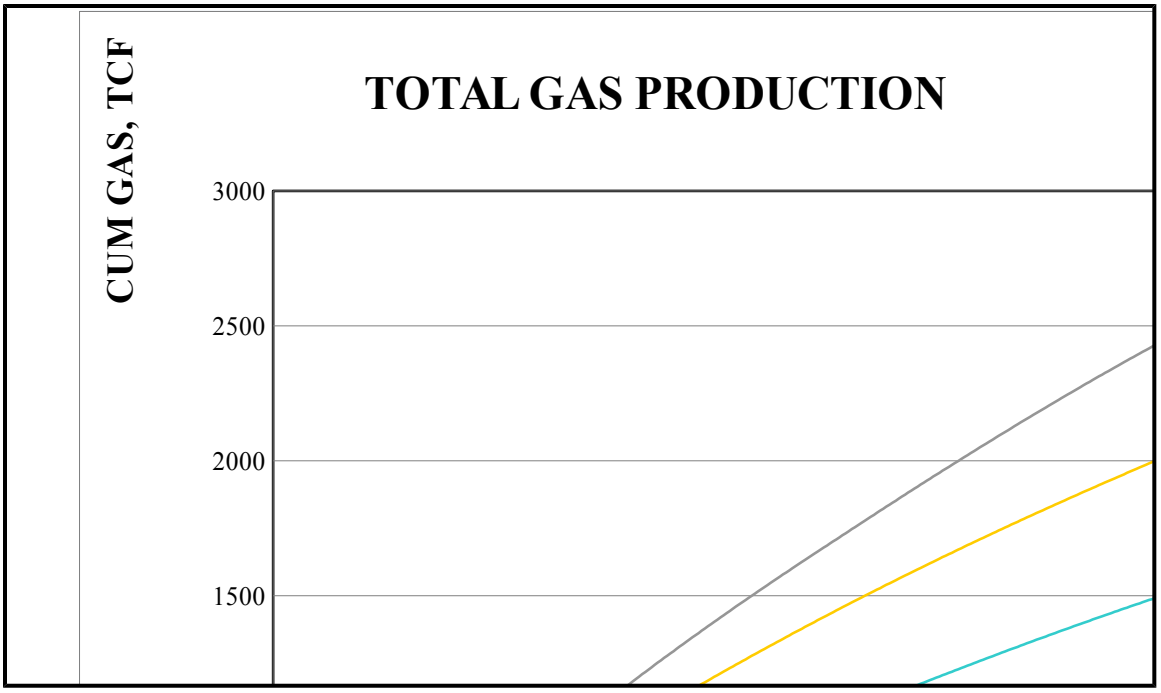

Figure RESULTS AND DISCUSSION.52: Shows total Gas Production before and after gas cycling

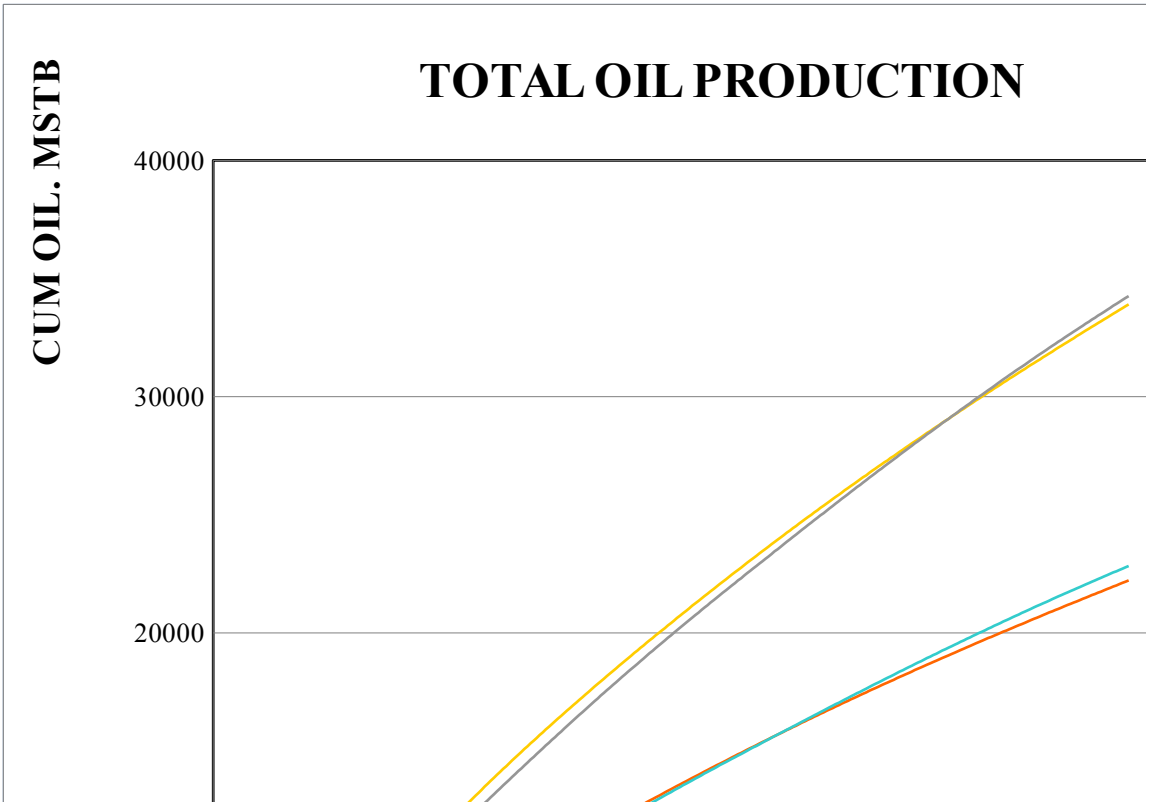

Figure RESULTS AND DISCUSSION.53: Shows the total oil production before and after gas cycling

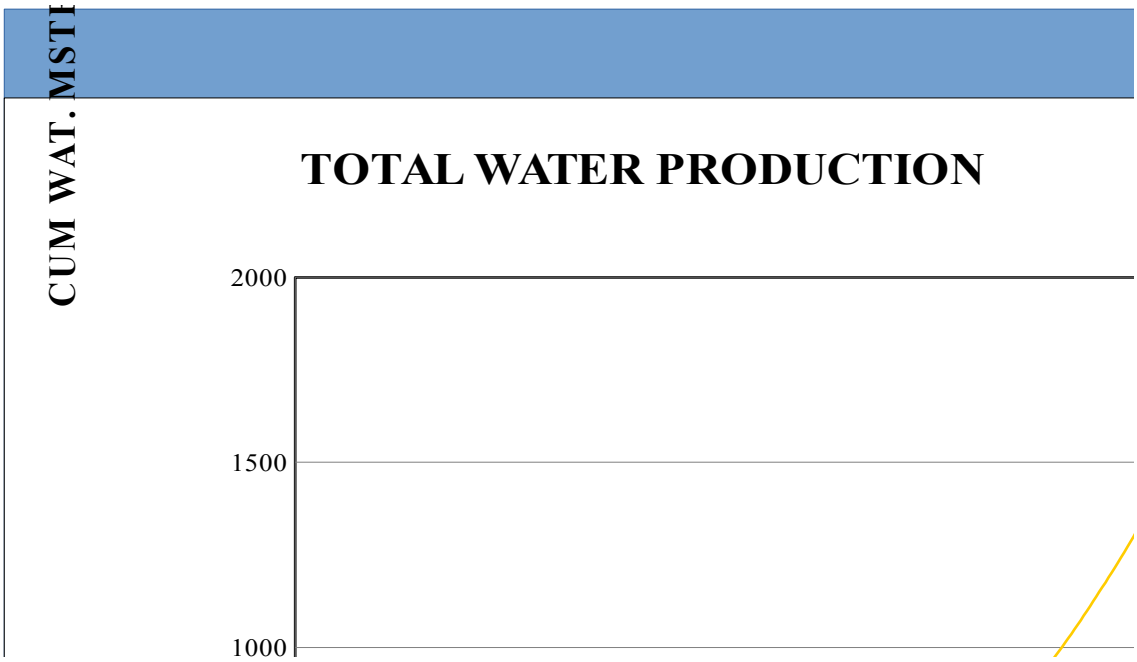

Figure RESULTS AND DISCUSSION.54: Shows the total water production before and after gas cycling

Analysis from Results

- Figure 4.45: the reservoir pressure was maintained at the dew point after recycling
- Figure 4.46: The length of the plateau extended to the end of production.
- Figure 4.47: There was a rise in GOR. Scenario 1 had the highest GOR.
- Figure 4.48: Scenario 1 had the highest cumulative gas production.
- Figure 4.49:There was an increase in oil production after produced gas were introduced into the reservoir. Scenario 1 had the highest cumulative oil production.
- Figure 4.50: Scenario 2 had the highest cumulative water production.

During production, not all the gas is able to flow towards the wellbore so it requires a driving mechanism to push it. Since the dew point of the field is the same as the initial pressure, the reservoir pressure depletes faster. Pressure maintenance mechanism is required to maintain the pressure and sustain the gas production. When the produced gas is recycled back into the reservoir, they first become miscible with the reservoir fluid. The injected gas displaces the heavy ends towards the wellbore leading to an increase in oil production, and a decrease in condensate accumulation in the reservoir. The intermediate component behind the displacing gas will vaporize and report as a gas phase to be produced. High gas and oil production lead to high gas oil ratio. High gas flow rate draws more water into the reservoir.

Summary

1. Gas cycling maintains the reservoir pressure.
2. Reservoir pressure sustains the gas production rate.
3. GOR is continually raised in production time.
4. The high gas flow rate led to high water production.
5. Gas cycling reduces condensate accumulation.
6. Horizontal wells reduce condensate blockage.
7. Recycling produced gas increases total oil and gas production.

4.5 Economic Analysis

The Net Present Value was used to analyze the profitability of each scenario and make a decision with regards to capital budgeting.

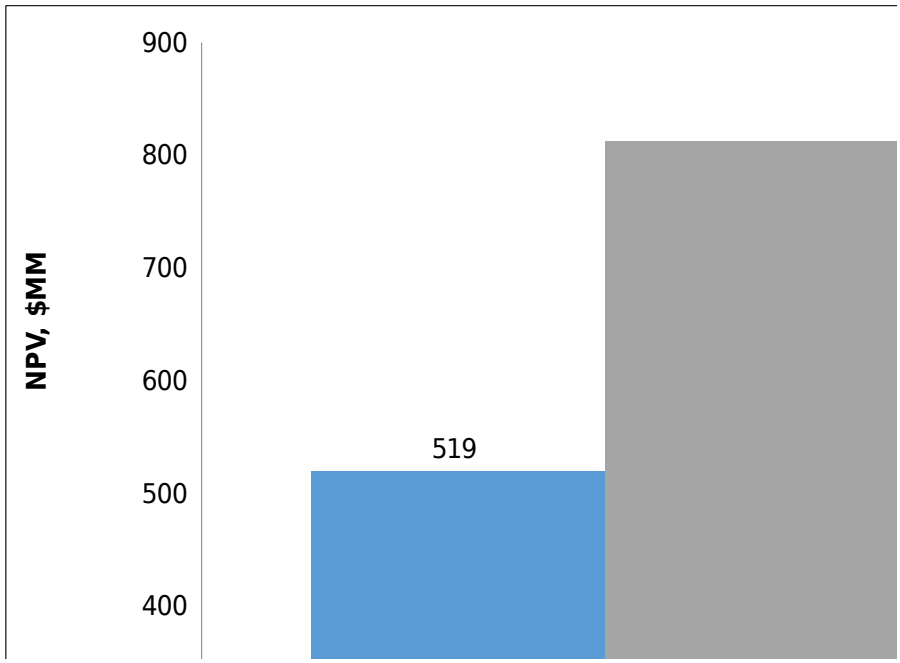

Figure RESULTS AND DISCUSSION.55: Shows the NPV of field at the end of 15 years

It was observed from Figure 4.51 that, scenario 2 gave the highest NPV with or without gas cycling. High oil production and cost of capital expenditure affects NPV.

Also, NPV takes into account price of oil. The higher the price the higher the NPV

Summary

- Scenario 2 with gas cycling was the best option for this field.

Condensate banking kills the well. It is therefore advisable to, recycle produced gas into the reservoir. It is more economical to produce with gas cycling from the beginning of production since the dew point is the same as the reservoir pressure. It will not only maintain the pressure, but help reduce condensate banking and sustain the gas rate.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

Field development plans have been proposed in this study for producing a gas condensate Niger Delta field. Based on the results of the work, the following conclusions are drawn:

1. Both Geometric and Harmonic permeability methods gave similar results. This may be due to the homogeneous nature of the formation.
2. Producing a gas condensate reservoir at a higher reservoir pressure through gas cycling tends to increase gas oil ratio, oil and gas production.
3. Gas cycling with vertical wells proved to be economical as a result of higher cash flow and effects of injection costs leading to a high NPV of $843 MM.

5.2 Recommendation

Further research should be performed with different gas and injection rates.

To appreciate more research works using Sensor, students need intensive training on Sensor.

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APPENDIX

APPENDIX A

RESERVOIR AND SEPARATOR CONDITIONS

GENERAL RESERVOIR CONDITIONS		
Reservoir Conditions:		
	Pressure:	4609 [Psia]
	Temperature:	192.3 [F]
Standard Conditions:		
	Pressure:	14.7 [Psia]
	Temperature:	60 [F]
Summary of Fluid Properties (RSS):		
Reservoir fluid mole % C7+	2.95 [%]	
Reservoir fluid molecular wt	23.74 [g/mol]	
Propeties at initial Conditions		
Compressibility Psia):	98.948 x E-06 [1/Psia]	
Density:	0.265	[g/cm^3]
Gas FVF (Bg):	0.00378	[cu ft/Scf]
Z-F actor	0.945	
Propeties at Saturation Conditions		
	Dew point Point:	4609 [Psia] at 203.4 [F]
	Density:	0.265 [g/cm^3]
Gas FVF (Bg):		0.00378 [cu ft/Scf]
Compressibility Psia):	98.948 x E-06 [1/Psia]	
Multi stage separator test		
Gas oil Ratio	21,459.20	[Scf/Stb]
	[cgr=46.6bbls/mmscf]	
Gravity	Constant volume depn.- residual oil	0.788 [g/cc], 48.0 [°API]
	Multi stage Separator test	0.787 [g/cc], 48.2 [°API]

FLUID PROPERTIES

Reservoir Fluid Composition

No	Component	Separator Gas	Separator Liquid	Reservoir Fluid
		[mol %]	[mol %]	[mol %]
1	N2	0.21	0	0.2

2	CO2	0.72	0.04	0.7
3	H2S	0	0	0
4	C1	82.35	2.21	79.57
5	C2	10.38	1.29	10.06
6	C3	4.07	1.67	3.99
7	i-C4	0.78	0.86	0.78
8	n-C4	0.69	1.89	0.73
9	i-C5	0.39	1.62	0.43
10	n-C5	0.28	1.99	0.34
11	C6	0.06	5.33	0.24
12	C7	0.05	10.42	0.41
13	C8	0.02	24.57	0.87
14	C9	0	12.36	0.43
15	C10	0	7.63	0.26
16	C11	0	5.83	0.2
17	C12	0	4.29	0.15
18	C13	0	3.99	0.14
19	C14	0	3.01	0.1
20	C15	0	2.77	0.1
21	C16	0	1.83	0.06
22	C17	0	1.32	0.05
23	C18	0	1.18	0.04
24	C19	0	0.81	0.03
25	C20+	0	3.09	0.11
	Total	100	100	100
	Sample:			
	MW [g/mol]	19.96	133.66	23.74
	Gravity [air = 1]	0.689	0.788 [g/cm^3]	
	MW C7+ [g/mol]	99.32	143.13	**142.09**
	Mol % C7+	0.07	83.1	**2.95**
	FIELD GOR [SCF/Bbl]			**21470.7**

Shrinkage [ST bbl/sep bbl]		0.964	

CCE DATA

NO	**Pressure**	**Rel. Vol. LAB**	**Rel. Vol. SIMULATION**	**AAE**		**LAB Retrograde Liquid %**	**SIMULATION Retrograde Liquid %**	**LAB Z**	**SIMULATION Z**	**AAE**
	[Psia]	[Vtot/ Vsat]		DIFF		[Vliq/ Vsat]				
1	1375	3.044	3.032	0.004		1.729	2.896			
2	1613	2.489	2.562	0.029		2.046	3.493			
3	2037	1.945	2.014	0.036		2.502	4.513			
4	2552	1.563	1.615	0.033		2.828	5.539			
5	3032	1.338	1.381	0.032		2.903	6.101			
6	3542	1.181	1.213	0.027		2.731	6.000			
7	4028	1.081	1.099	0.017		2.171	4.748			
8	**4609**	**1.000**	1.000	0.000		**0.000**	0.002	0.945	0.925	2.079

9	5032	0.959	0.955	0.004	0.003	0.000	0.000	0.989	0.964	2.576
10	5534	0.919	0.912	0.007	0.014	0.000	0.000	1.042	1.010	3.046
11	6037	0.886	0.876	0.011	0.027	0.000	0.000	1.096	1.058	3.456
TOTAL AAE				**1.82%**						

SEPARATOR DATA

Stage	**PRESSURE**	**TEMP**	**LAB**	**SIMULATION**	**DIFF IN**	**LAB**	**SIMULATIO**	**DIFF IN**
			GOR			**OIL DENSITY**		
	[Psia]	**[F]**	**[SCF/STB]**	**[SCF/STB]**		**[g/cc]**	**[g/cc]**	
Stage 1	480	106	21,229	21,727	2.3473	0.7360	0.7262	0.0135
Stage 2	200	100	111	114	2.5451	0.7550	0.7477	0.0098
Stage 3	60	60	56	59	5.2779	0.7770	0.7757	0.0017
Stage 4	15	60	64	67	4.0284	0.7870	0.7879	0.0012

GROUPED RESERVOIR COMPONENTS

AFTER GROUPING						
GRP1	N2	C1				
GRP2	CO2	H2S	C2			
GRP3	C3					
GRP4	iC4	nC4	iC5	nC5	C6	
C7::C8	C7::C8					

C9::C10	C9::C10					
C11::C15	C11::C15					

CRITICAL PROPERTIES AFTER MATCHING

PVT DATA FOR THE SENSOR							
CPT	TC	PC	MW	AC	ZCRIT	SHIFT	PCHOR
'GRP1'	342.8597	672.6229	16.0700	0.0111	0.7920	-0.1540	69.9759
'GRP2'	549.3310	732.0662	31.0049	0.1081	0.1069	-0.1002	112.5930
'GRP3'	665.6762	617.3964	44.0997	0.1530	0.0397	-0.0850	154.9986
'GRP4'	792.0146	513.3248	65.1691	0.2157	0.0252	-0.0574	212.7522
'C7::C8'	1073.4113	447.1361	111.7770	0.4084	0.0132	-8.9999	343.8553
'C9::C10'	1131.6685	403.9117	136.1800	0.4648	0.0106	3.8714	406.4217
'C11::C15'	1266.0698	321.3791	179.6410	0.6092	0.0124	2.9148	506.8547

BINARY COEFFICIENT INTERACTIVE DATA

BIN						
0.02017727	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	
0.01994986	0.00000000	0.00000000	0.00000000	0.00000000		
0.02862805	0.00000000	0.00000000	0.00000000			
0.01000000	0.00423454	0.00073567				
0.00700760	0.00158570					
0.00253429						

ECONOMIC PARAMETER

Economic Parameter	**Cost (USD)**	
Vertical well		
Cost of drilling a vertical well	8,000,000	
Capital expenditure (CAPEX) per vertical well	8,000,000	
Operating Expenditure (OPEX) per vertical well		
Horizontal well		
Cost of drilling a horizontal well	16,000,000	
Capital expenditure (CAPEX) per horizontal well	16,000,000	
OTHERS		
Condensate price	44	$/bbl
Cost of gas injection	12	Per MScf
Cost of water injection	6	Per MMbbl
Discount rate	8%	
Condensate price	44	$/bbl
Gas price	2.5	$/MCF

SCENARIO	TYPE OF WELL	NO	NATURAL DEPLETION	GAS CYC
SCENARIO 1	HORIZONTAL	4	64,000,000	80,000,000
SCENARIO 2	VERTICAL	4	32,000,000	48,000,000
GAS CYC	VERTICAL	2	16,000,000	

SCENARIO 1 – NATURAL DEPLETION

Oil Price ($/bbl)	44	**Discount**	0.08		Gas price $/MCF	**2.5**
	1	**2**	**3**	**4**	**5**	**6**
YEAR	2000	2001	2002	2003	2004	2005
Oil Production (STB/d)	2,233,275	1,973,433	1,855,343	1,729,340	1,644,092	1,588,352
Oil Price ($/bbl)	44.00	44.00	44.00	44.00	44.00	44.00
Gross Revenue Oil	98,264,112	86,831,070	81,635,074	76,090,975	72,340,064	69,887,502
Total Revenue	**98,264,112**	**86,831,070**	**81,635,074**	**76,090,975**	**72,340,064**	**69,887,502**
Water Production(STB/d)	17,053	17,882	18,879	20,204	21,716	23,461
Water Production($/STB)	102,319.87	107,291	113,274	121,221	130,298	140,769
Opex	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Capex	64,000,000					
Discount	1.08	1.17	1.26	1.36	1.47	1.59
	95,161,792	83,723,780	78,521,801	72,969,754	69,209,766	66,746,733
	88,112,771	71,779,647	62,333,137	53,634,947	47,103,004	42,061,764
				583,087,571		
				519,087,571		

7	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
2006	2007	2008	2009	2010	2011	2012	2013	2014
1,514,293	1,442,344	1,379,832	1,355,601	1,320,399	1,279,210	1,230,592	1,173,193	1,116,699
44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
66,628,907	63,463,121	60,712,628	59,646,427	58,097,553	56,285,258	54,146,056	51,620,476	49,134,775
66,628,907	**63,463,121**	**60,712,628**	**59,646,427**	**58,097,553**	**56,285,258**	**54,146,056**	**51,620,476**	**49,134,775**
25,696	28,197	31,298	35,585	43,129	55,800	78,252	124,954	257,894
154,178	169,185	187,787	213,509	258,775	334,798	469,510	749,724	1,547,361
3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
1.71	1.85	2.00	2.16	2.33	2.52	2.72	2.94	3.17
63,474,729	60,293,937	57,524,841	56,432,918	54,838,778	52,950,461	50,676,546	47,870,752	44,587,414
37,036,895	32,574,938	28,776,742	26,139,360	23,519,412	21,027,356	18,633,661	16,298,126	14,055,812

SCENARIO 2

Oil Price ($/bbl)	**44**	Discount	0.08		Gas price $/MCF	2.50
	1	**2**	**3**	**4**	**5**	**6**
YEAR	2000	2001	2002	2003	2004	2005
Oil Production (STB/d)	2,353,106	2,062,552	1,899,338	1,779,179	1,640,259	1,522,651
Oil Price ($/bbl)	44.00	44.00	44.00	44.00	44.00	44.00
Gross Revenue oil	103,536,681	90,752,275	83,570,870	78,283,865	72,171,387	66,996,623
Total Revenue	**103,536,681**	**90,752,275**	**83,570,870**	**78,283,865**	**72,171,387**	**66,996,623**
Water Production(STB/d)	28,403	29,781	31,264	32,938	35,963	39,430
Water Production ($/STB)	170,419	178,688	187,582	197,628	215,778	236,581
OPEX	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
CAPEX	32,000,000					
Discount	1.08	1.17	1.26	1.36	1.47	1.59
	100,366,263	87,573,587	80,383,288	75,086,237	68,955,609	63,760,042
	92,931,725	75,080,236	63,810,846	55,190,625	46,930,029	40,179,642
				575,480,708		
				543,480,708		

7	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
2006	2007	2008	2009	2010	2011	2012	2013	2014
1,437,525	1,371,989	1,314,927	1,258,840	1,203,430	1,154,750	1,112,147	1,073,001	1,039,307
44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
63,251,113	60,367,512	57,856,798	55,388,957	52,950,906	50,809,019	48,934,470	47,212,026	45,729,496
63,251,113	**60,367,512**	**57,856,798**	**55,388,957**	**52,950,906**	**50,809,019**	**48,934,470**	**47,212,026**	**45,729,496**
43,068	47,390	52,885	61,204	76,270	105,202	150,661	189,808	275,733
258,406	284,338	317,309	367,226	457,621	631,211	903,969	1,138,846	1,654,398
3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
1.71	1.85	2.00	2.16	2.33	2.52	2.72	2.94	3.17
59,992,708	57,083,174	54,539,488	52,021,731	49,493,285	47,177,808	45,030,501	43,073,180	41,075,098
35,005,169	30,840,263	27,283,323	24,096,127	21,226,822	18,734,957	16,557,622	14,664,740	12,948,584

SCENARIO 1CYC

Oil Price ($/bbl)	44	**Discount**	0.08		**Gas price $/MCF**	2.5
	1	**2**	**3**	**4**	**5**	**6**
YEAR	2000	2001	2002	2003	2004	2005
Oil Production (STB/d)	3,349,913	2,960,150	2,783,014	2,594,011	2,466,139	2,382,528
Oil Price ($/bbl)	44.00	44.00	44.00	44.00	44.00	44.00
Gross Revenue oil	147,396,168	130,246,606	122,452,612	114,136,462	108,510,096	104,831,253
Total Revenue	**147,396,168**	**130,246,606**	**122,452,612**	**114,136,462**	**108,510,096**	**104,831,253**
Water Production(STB/d)	23,448	24,587	25,959	27,780	29,860	32,259
Water Production ($/STB)	140,690	147,525	155,752	166,679	179,160	193,557
OPEX	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
CAPEX	80,000,000					
Discount	1.08	1.17	1.26	1.36	1.47	1.59
	144,255,479	127,099,081	119,296,860	110,969,783	105,330,936	101,637,696
	133,569,888	108,966,976	94,701,694	81,566,103	71,686,465	64,048,989
				887,730,195		
				807,730,195		

7	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
2006	2007	2008	2009	2010	2011	2012	2013	2014
2,271,440	2,163,516	2,069,749	2,033,401	1,980,598	1,918,816	1,845,888	1,759,789	1,675,049
44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
99,943,361	95,194,682	91,068,942	89,469,640	87,146,330	84,427,887	81,219,084	77,430,715	73,702,163
99,943,361	**95,194,682**	**91,068,942**	**89,469,640**	**87,146,330**	**84,427,887**	**81,219,084**	**77,430,715**	**73,702,163**
35,333	38,772	43,034	48,929	59,303	76,724	107,596	171,812	354,604
211,995	232,629	258,207	293,575	355,816	460,347	645,577	1,030,871	2,127,622
3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
1.71	1.85	2.00	2.16	2.33	2.52	2.72	2.94	3.17
96,731,366	91,962,053	87,810,735	86,176,065	83,790,514	80,967,540	77,573,507	73,399,844	68,574,541
56,441,823	49,684,236	43,927,230	39,916,192	35,936,315	32,153,324	28,523,618	24,989,787	21,617,555

SCENARIO 2 CYC

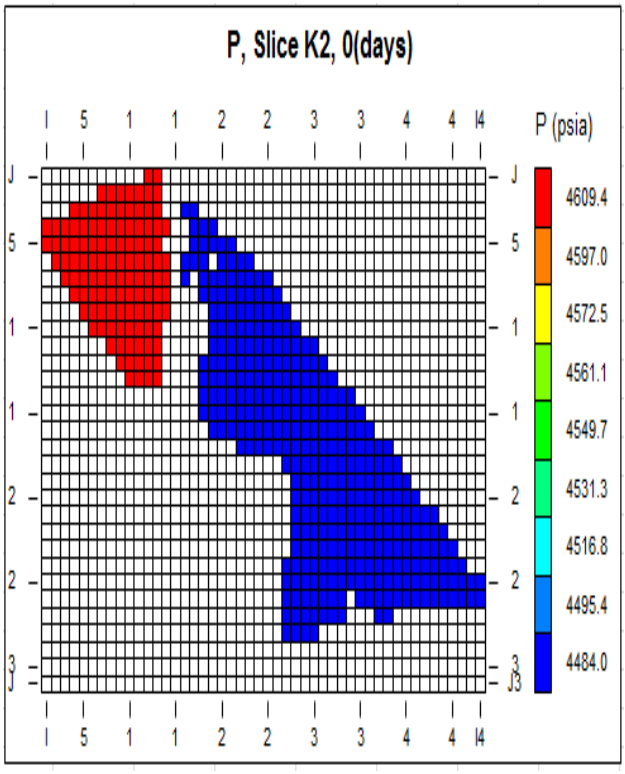
Oil Price ($/bbl)	44	discount	**0.08**		Gas price $/MCF	**2.5**
	1	**2**	**3**	**4**	**5**	**6**
YEAR	2000	2001	2002	2003	2004	2005
Oil Production (STB/d)	3,589,538	3,146,313	2,897,339	2,714,042	2,502,127	2,322,722
Oil Price ($/bbl)	44.00	44.00	44.00	44.00	44.00	44.00
Gross Revenue oil	157,939,679	138,437,751	127,482,901	119,417,856	110,093,597	102,199,772
Total Revenue	**157,939,679**	**138,437,751**	**127,482,901**	**119,417,856**	**110,093,597**	**102,199,772**
Water Production (STB/d)	44,972	47,154	49,501	52,152	56,941	62,431
Water Production ($/STB)	269,829	282,923	297,005	312,911	341,648	374,587
Opex	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Capex	48,000,000					
Discount	1.08	1.17	1.26	1.36	1.47	1.59
	154,669,850	135,154,828	124,185,896	116,104,945	106,751,949	98,825,185
	143,212,824	115,873,480	98,582,768	85,340,600	72,653,583	62,276,630
				891,171,178		
				843,171,178		

	operating water	**6**						
7	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
2006	2007	2008	2009	2010	2011	2012	2013	2014
2,192,868	2,092,896	2,005,851	1,920,293	1,835,768	1,761,510	1,696,521	1,636,805	1,585,407
44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
96,486,197	92,087,416	88,257,456	84,492,896	80,773,781	77,506,446	74,646,922	72,019,425	69,757,905
96,486,197	**92,087,416**	**88,257,456**	**84,492,896**	**80,773,781**	**77,506,446**	**74,646,922**	**72,019,425**	**69,757,905**
68,190	75,034	83,734	96,907	120,761	166,570	238,547	300,529	436,577
409,143	450,201	502,407	581,441	724,567	999,418	1,431,284	1,803,173	2,619,464
3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
1.71	1.85	2.00	2.16	2.33	2.52	2.72	2.94	3.17
93,077,054	88,637,215	84,755,049	80,911,456	77,049,214	73,507,028	70,215,638	67,216,252	64,138,442
54,309,567	47,887,929	42,398,626	37,477,659	33,045,087	29,190,652	25,818,144	22,884,515	20,219,112

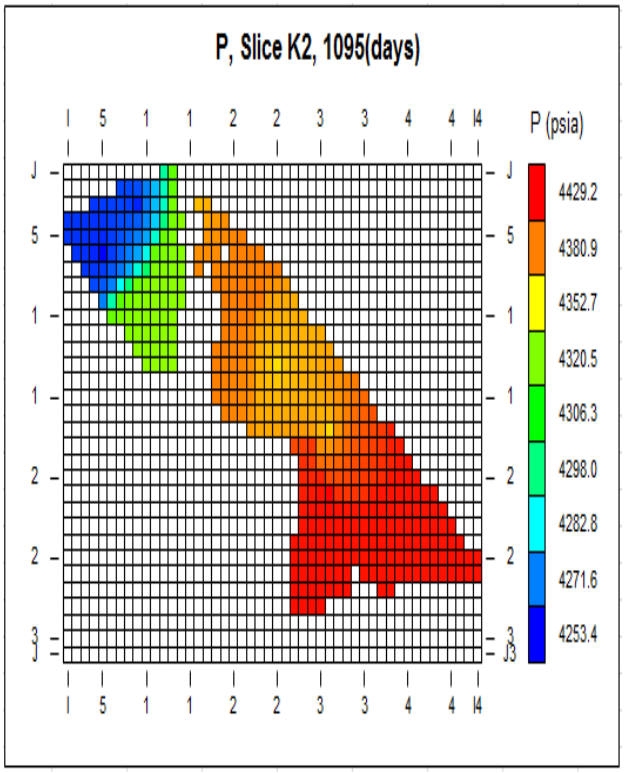
APPENDIX B

NATURAL DEPLETION-PRESSURE DISTRIBUTION - LAYER 2

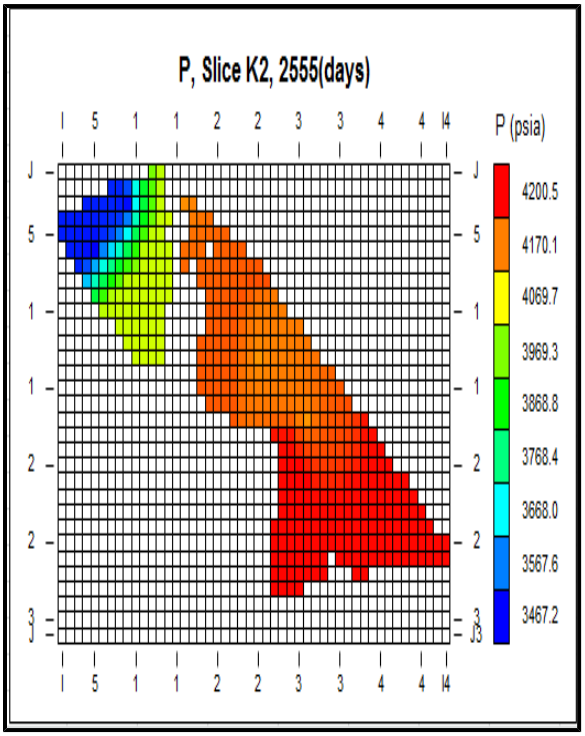
AT THE BEGINNING OF PRODUCTION

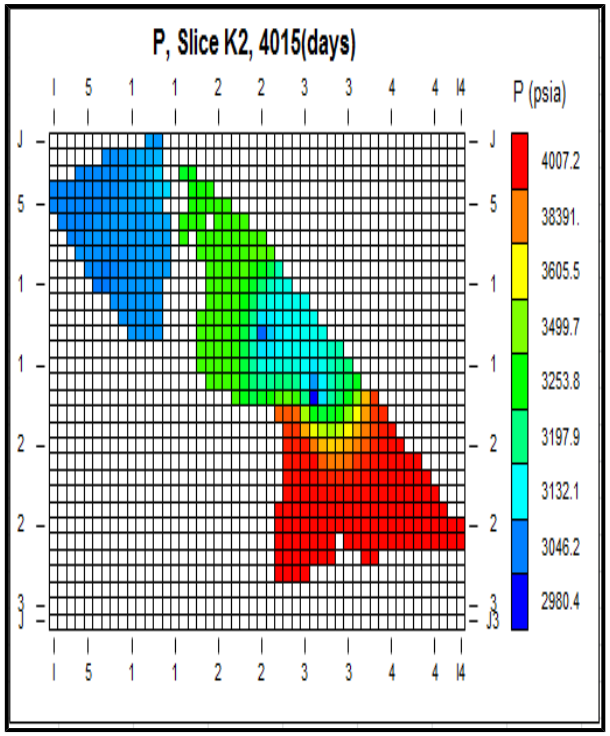


QUATERLY PRESSURE DISTRIBUTION

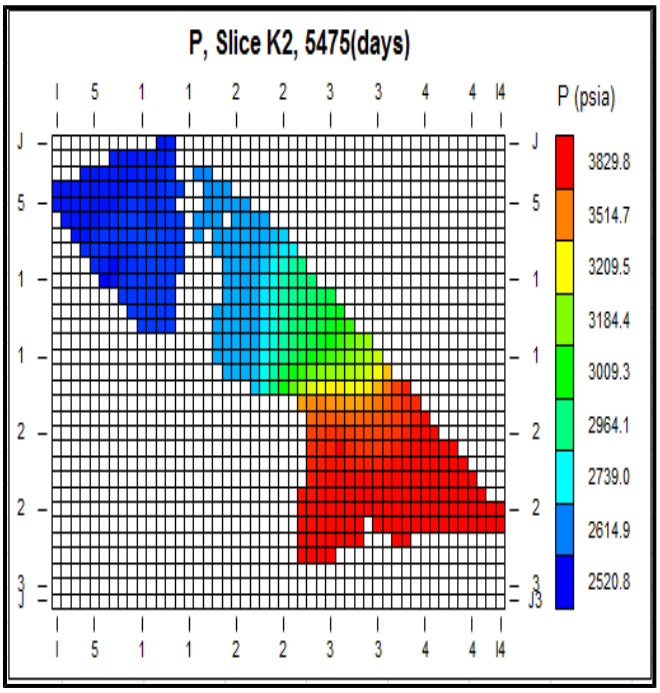


THIREE QUATERLY PRESSURE DISTRIBUTION





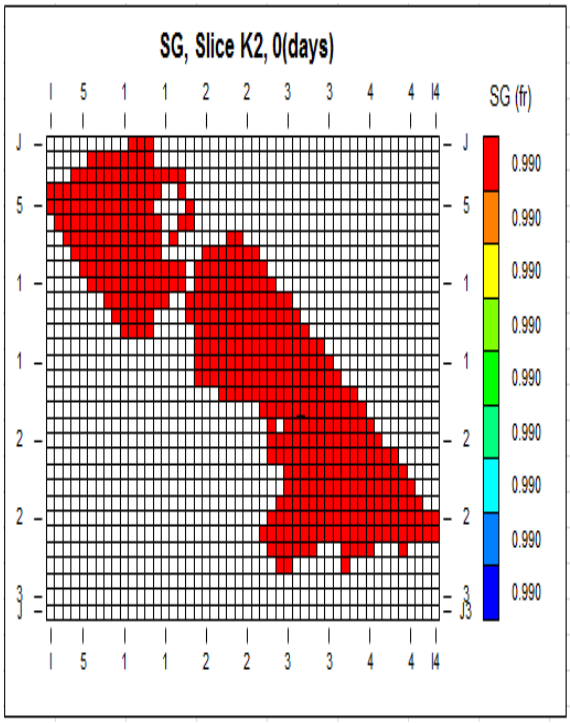
FINAL PRESSURE DISTRIBUTION



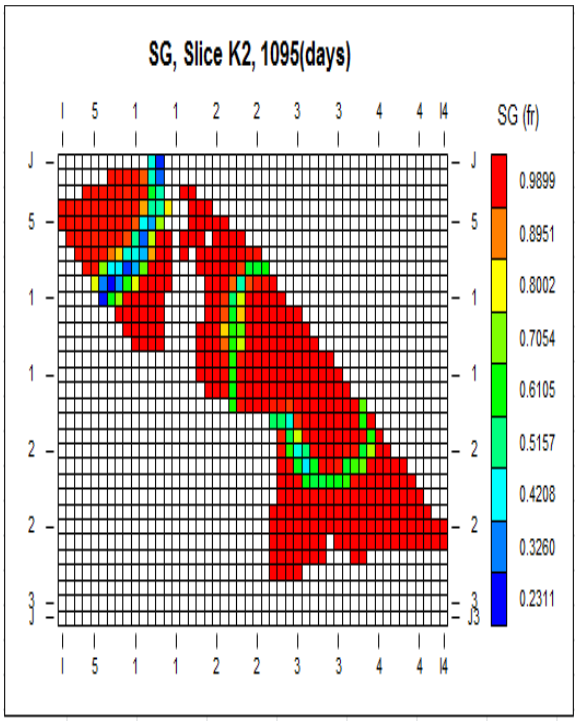
FLUID SATURATION DISTRIBUTION

GAS SATURTATION DISTRIBUTION

AT THE BEGINNING OF PRODUCTION DISTRIBUTION

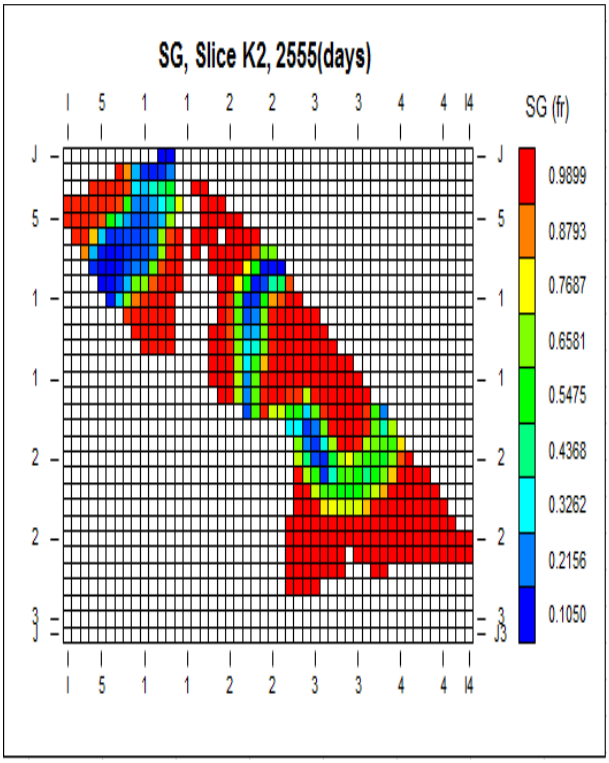


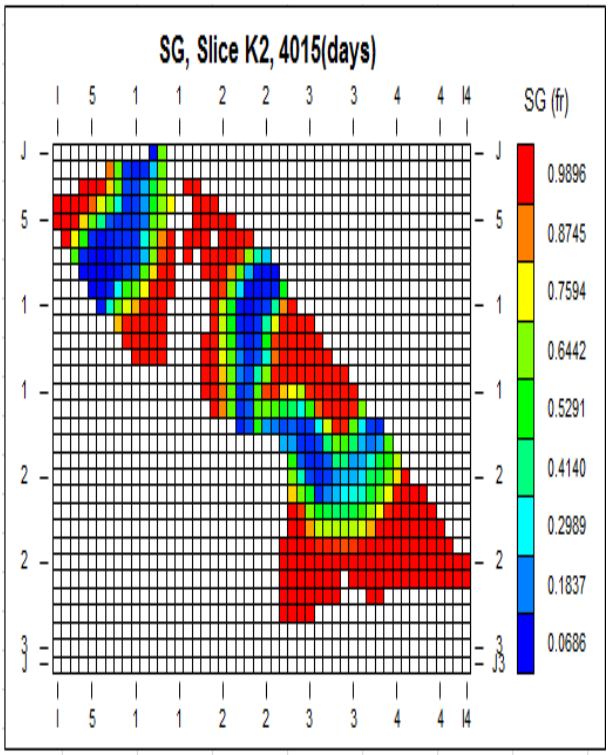
QUATERLY GAS SATURATION



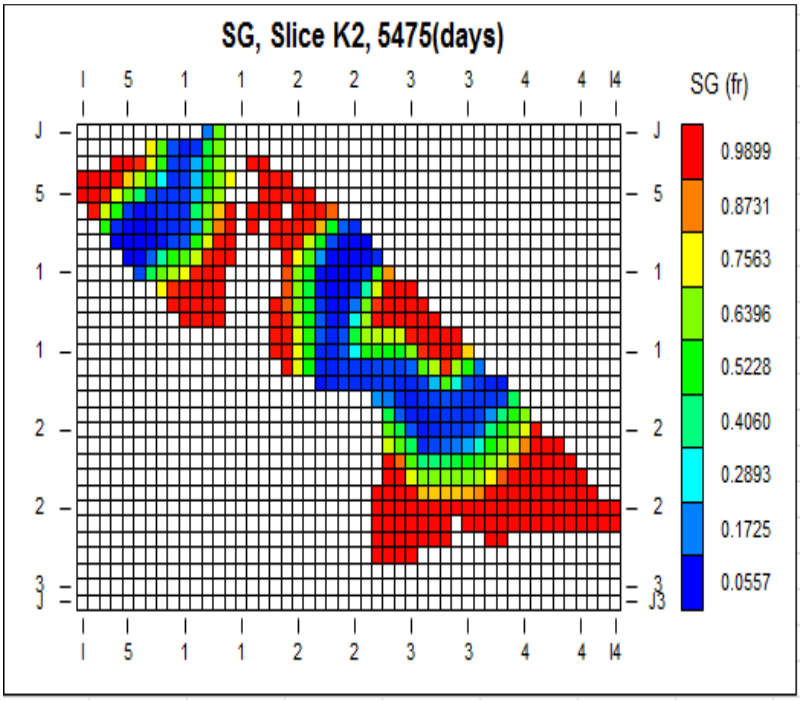
MID WAY GAS SATURATION DISTRIBUTION

THREE QUATERLY GAS SATURATION DISTRIBUTION



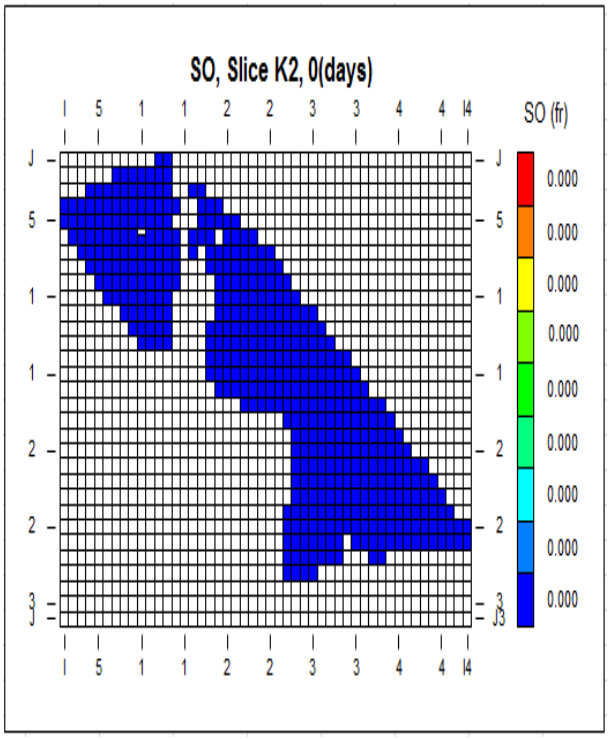


END GAS SATURATION DISTRIBUTION

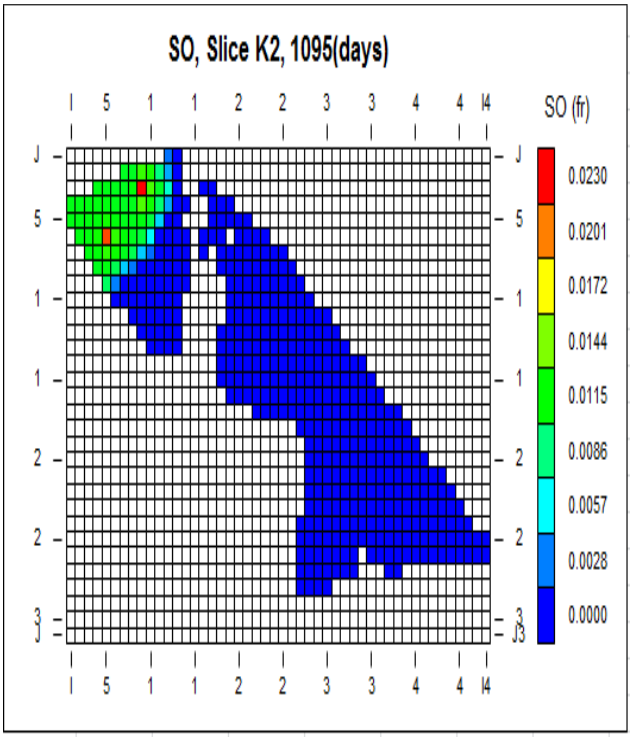


OIL SATURATION DISTRIBUTION

AT THE BEGINNING OF PRODUCTION

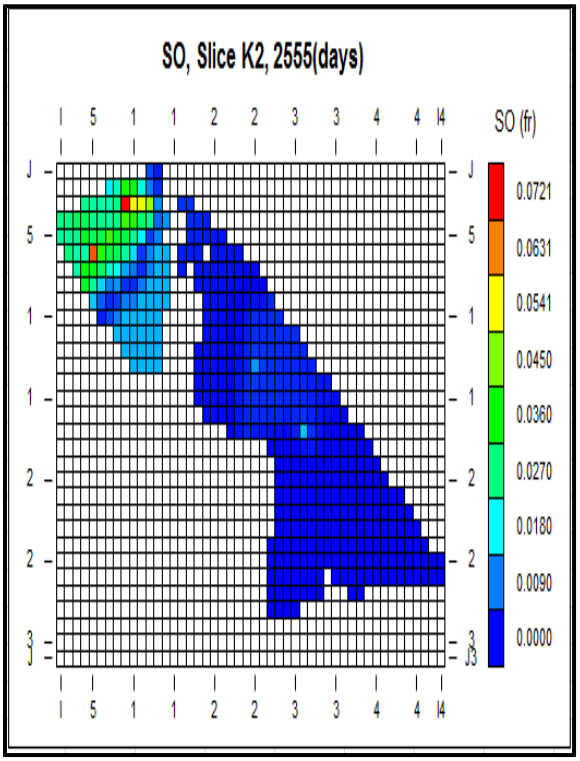


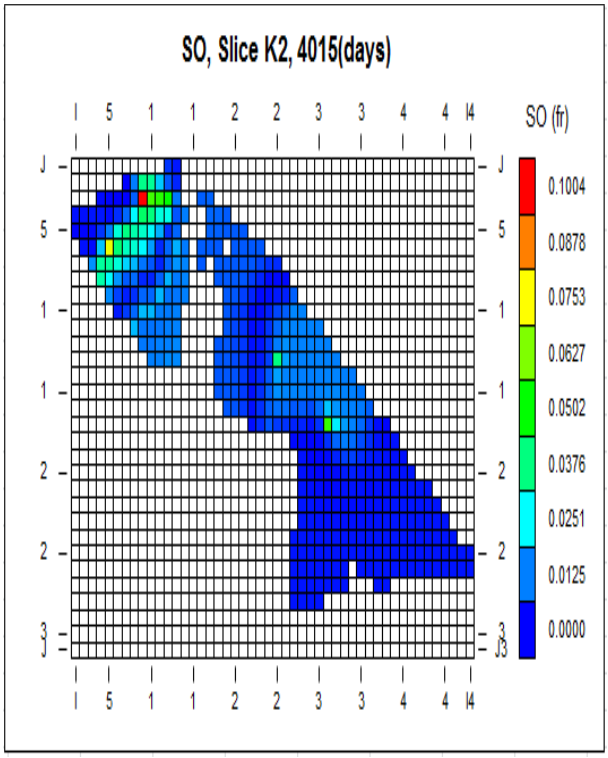
QUATERLY OIL SATURATION DISTRIBUTION



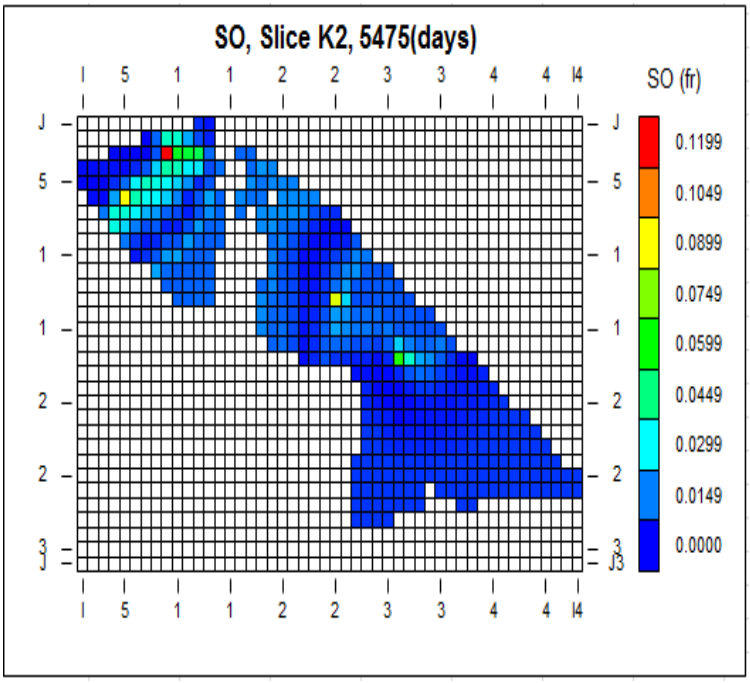
MID OIL SATURATION DISTRIBUTION

THREE QUATERLY OIL SATURATION DISTRIBUTION





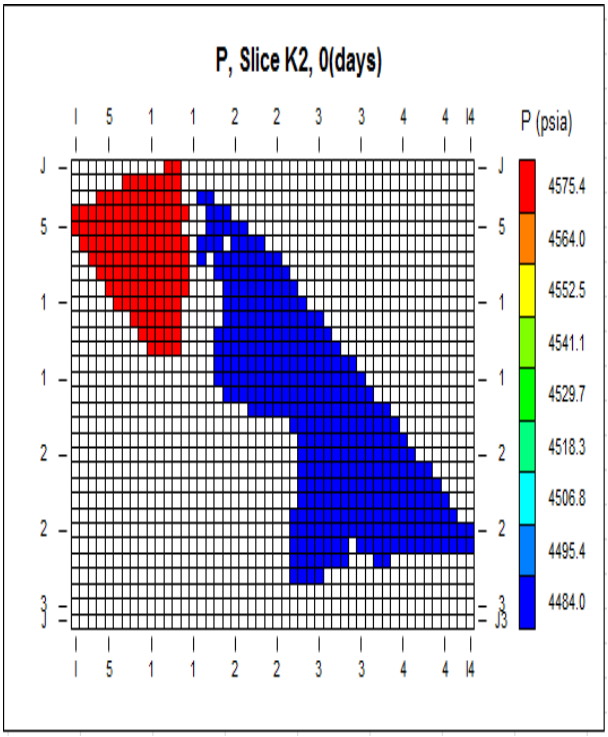
FINAL OIL SATURATION DISTRIBUTION

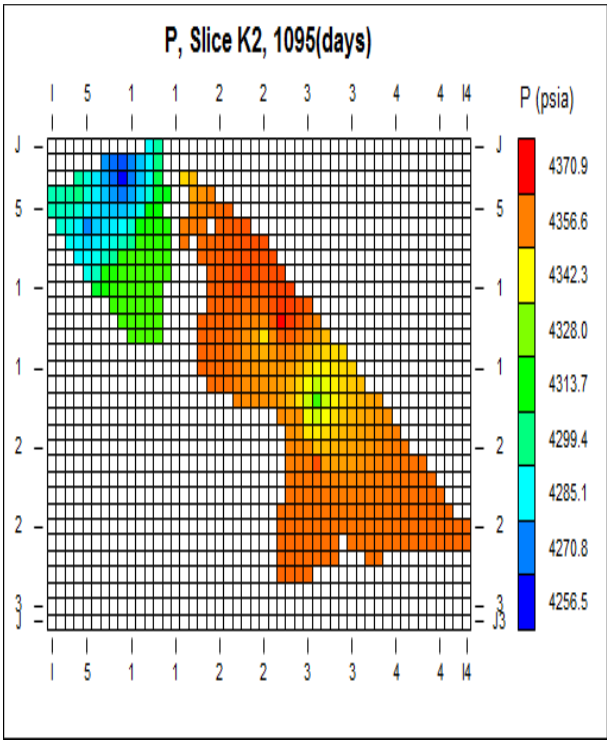


GAS CYCLING

PRESSURE DISTRIBUTION - LAYER 2

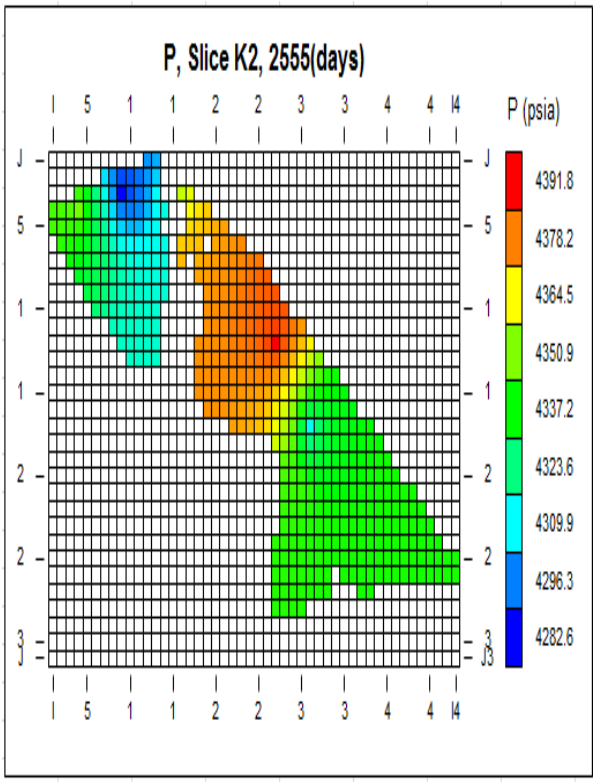
AT THE BEGINNING OF PRODUCTION **QUATERLY PRESSURE DISTRIBUTION**

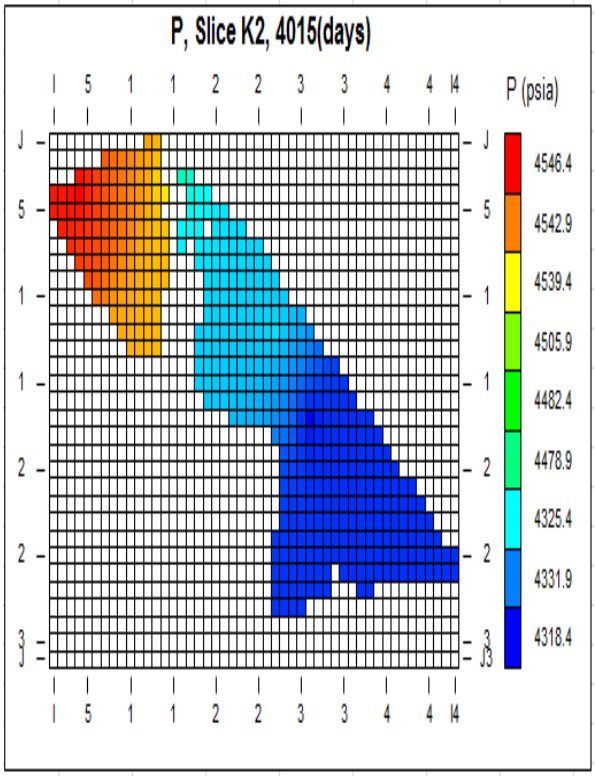




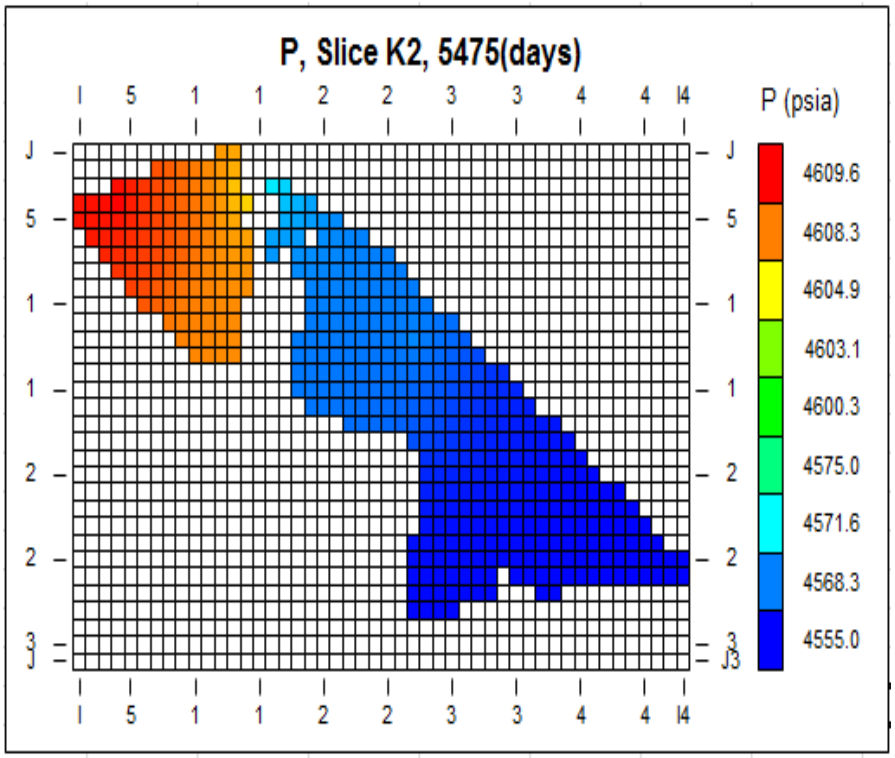
MID WAY PRESSURE DISTRIBUTION

THREE QUATERLY PRESSURE DISTRIBUTION



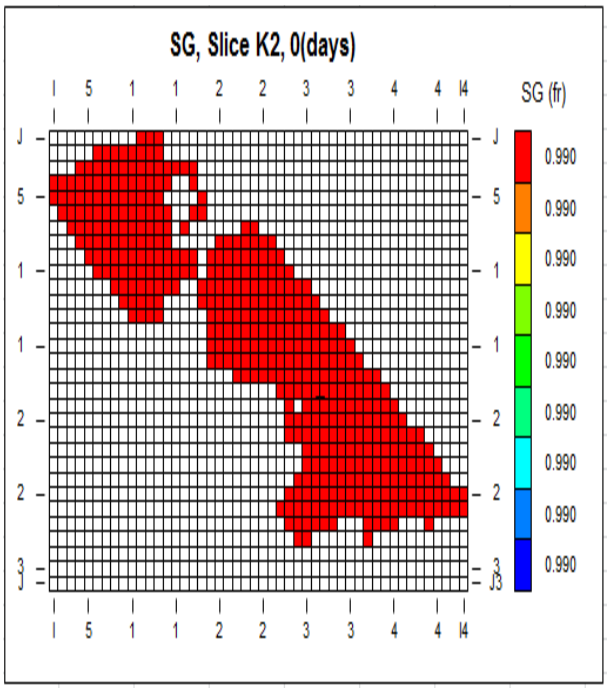


FINAL PRESSURE DISTRIBUTION

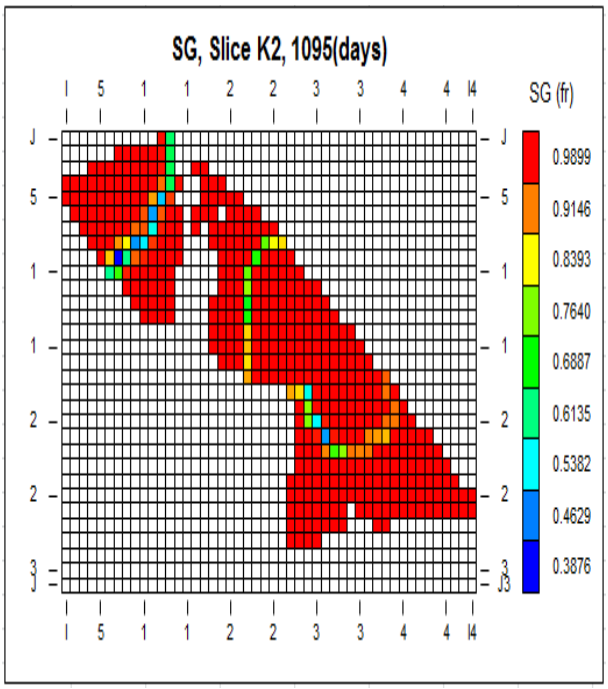


GAS SATURATION DISTRIBUTION- LAYER 2

AT THE BEGINNING OF PRODUCTION

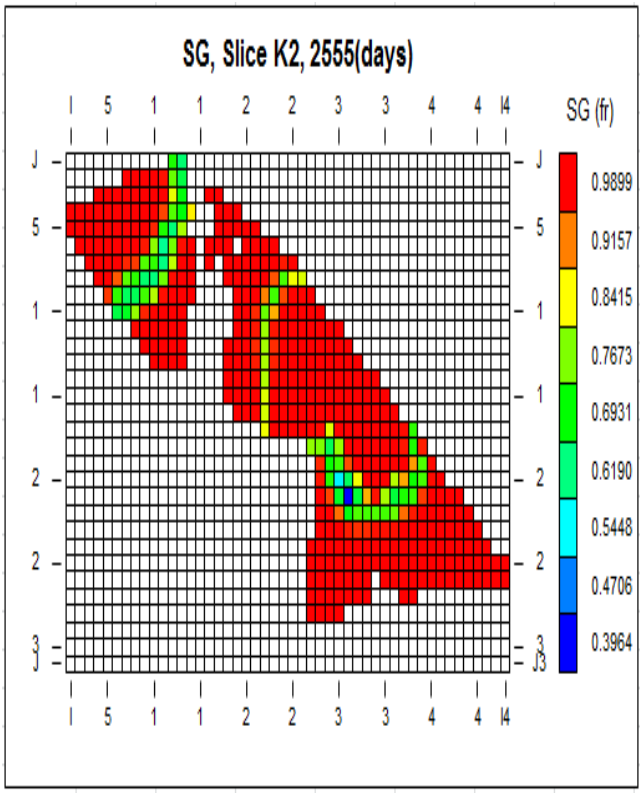


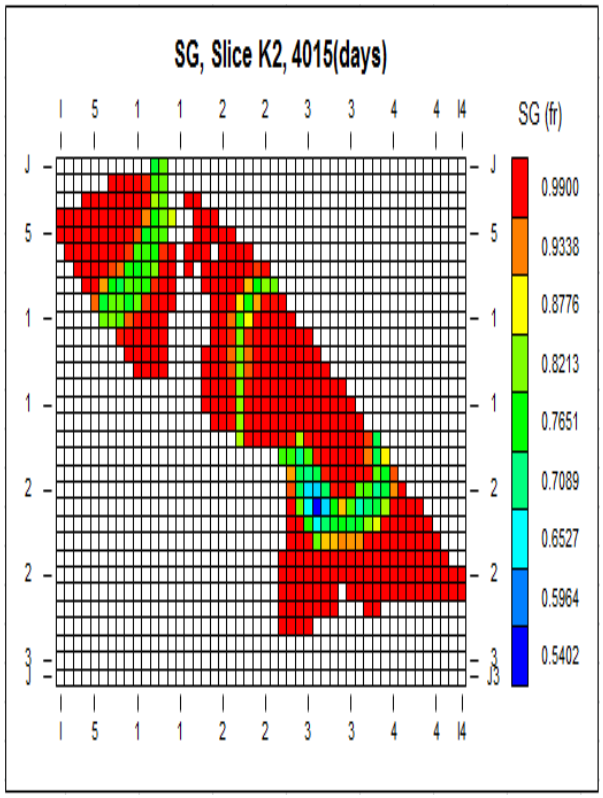
QUATERLY GAS SATURATION DISTRIBUTION



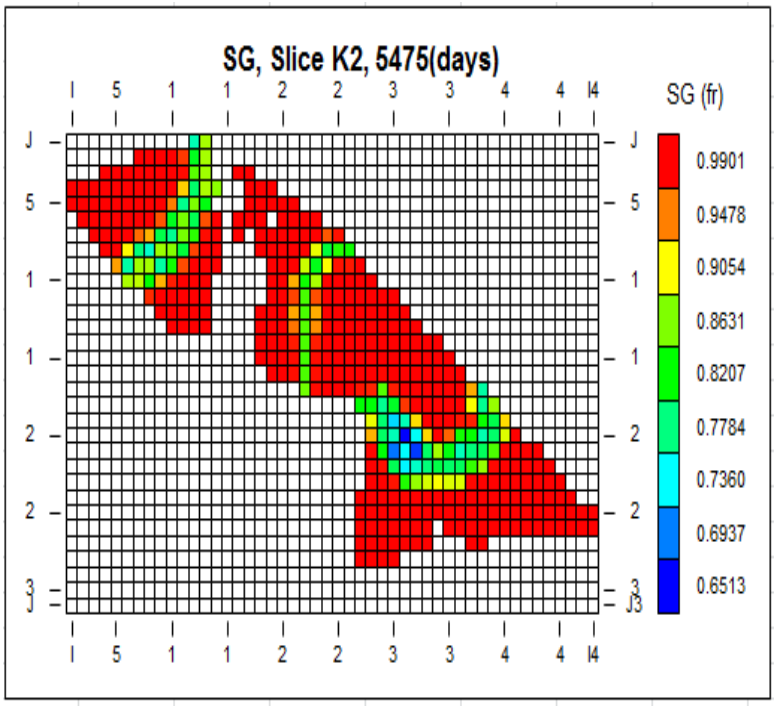
MID WAY GAS DISTRIBUTION

THREE QUATERLY GAS SATURATION DISTRIBUTION





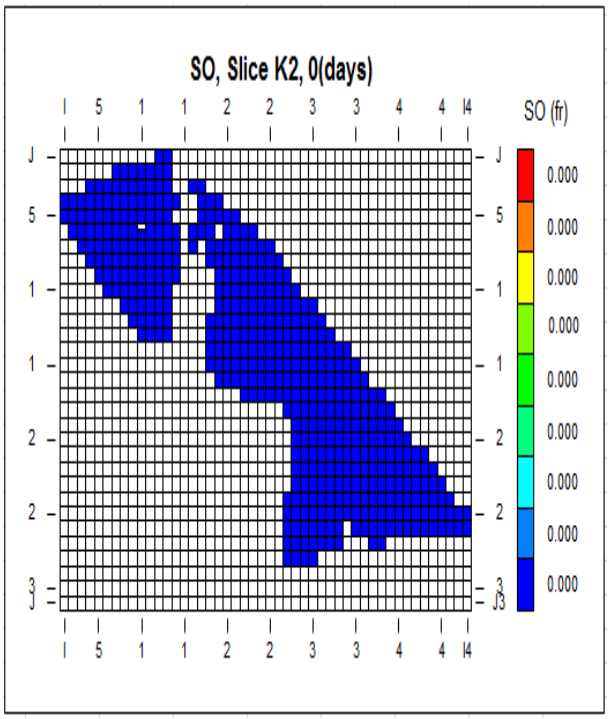
FINAL GAS SATURATION DISTRIBUTION

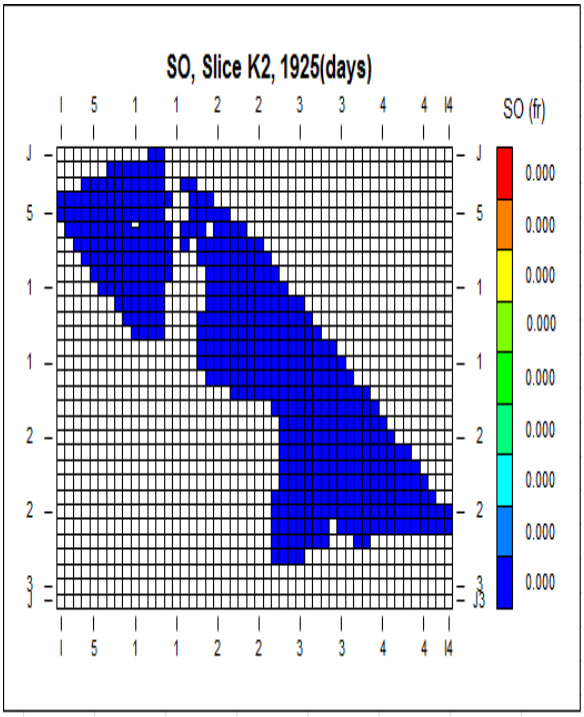


LAYER 2

OIL SATURATION

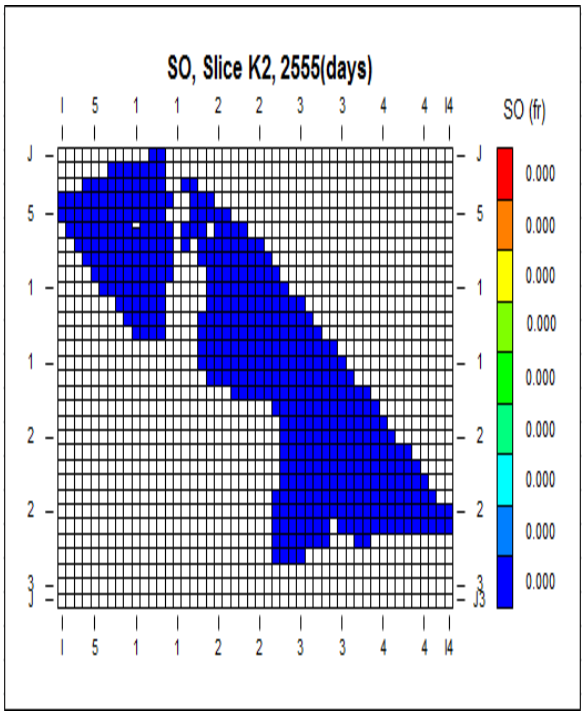
AT THE BEGINNING OF PRODUCTION **QUARTERLY WAY OIL SATURATION DISTRIBUTION**

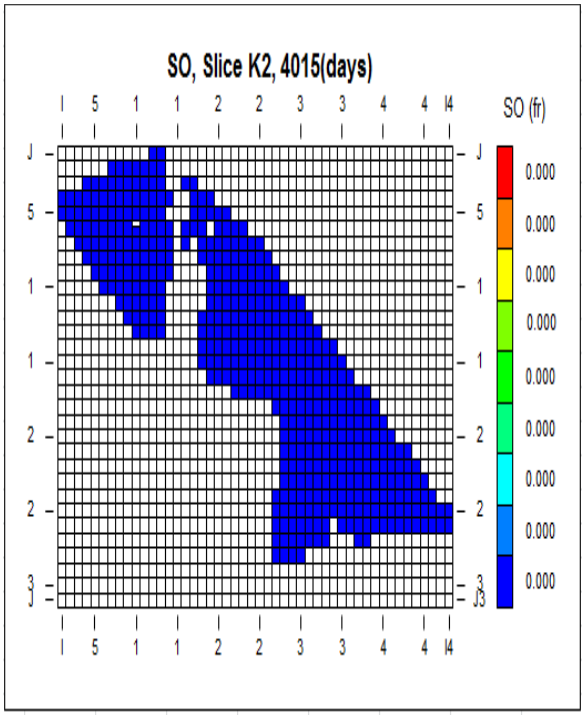




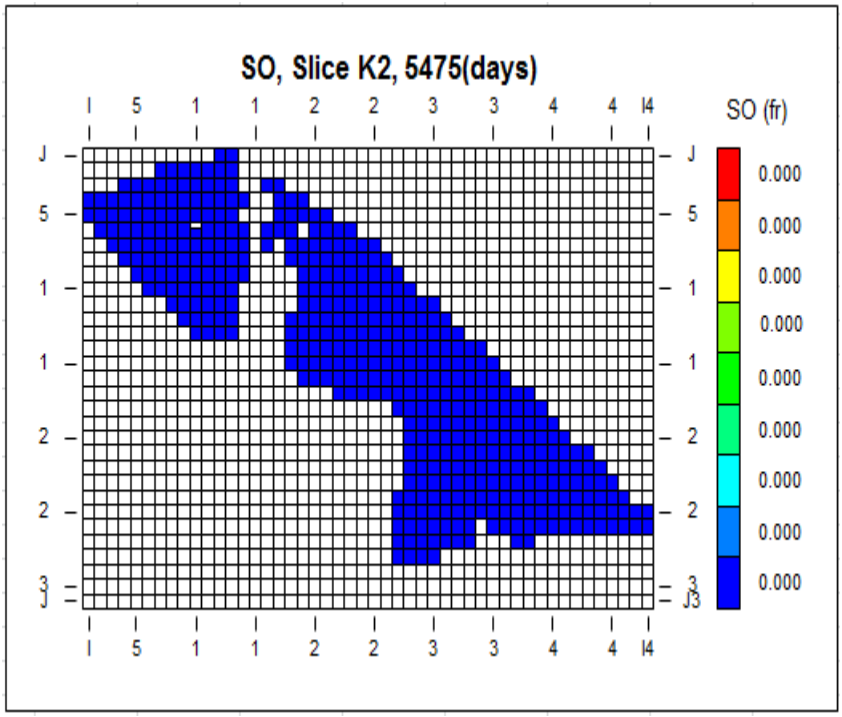
MID WAY -OIL SATURATION

THREE QUATERLY OIL SATURATION





FINAL OIL SATURATION DISTRIBUTION


SO, Slice K2, 5475(days)
SO (fr)
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