NTNU – Trondheim
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Petroleum Engineering
Submission date: June 2014
Supervisor: Curtis Hays Whitson, IPT

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## Abstract

It is well recognized that the liquid dropout in the reservoir from a gas condensate below dew point pressure does not only reduce the ultimate recovery of oil but can also reduce the gas well deliverability. Therefore, enhancing the ultimate oil and gas recoveries is the major challenge for reservoir engineer during development of gas condensate reservoir. In this report, the importance of water influx and water flooding on the performance of gas condensate reservoir is studied through fine gridded compositional simulation models. It is shown that water drive can significantly increase the ultimate oil and gas recoveries of a gas condensate reservoir.

The study did not include the economical analysis. However, comparison of ultimate oil and gas recoveries and field production time of different operations were made for feasibility analysis. The size of aquifer was found to have a large impact on recoveries and the recoveries of reservoir with large size aquifer had less ultimate recoveries than reservoir with medium size aquifer because of trapping of gas at higher reservoir abandonment pressure. As the trapped gas also contains solution oil, the ultimate oil recovery also decreased. Therefore, optimizing the recoveries from reservoir with larger aquifer size was needed and different reservoir development strategies were made to determine optimum plan of a particular water drive reservoir. It is shown that high gas rate production has resulted in low ultimate recoveries unlike gas reservoirs, which are produced at maximum rates to reduce the trapped gas volume. The effect of combination of different gas production rate is also discussed along with the co-production of water through water production well.

The performance of gas condensate reservoir under water injection was found to have similar behavior with increasing injection rate as that of increasing size of aquifer- ultimate recovery of oil increased to some point and then decreased afterword. The need to find optimum injection rate to optimize total hydrocarbon recovery was discussed as maximum ultimate gas recovery and ultimate oil recovery was found to occur at different injection rates. During initial full pressure maintenance case, gas-oil ratio was successfully maintained at its initial value and the optimum plan in this particular case was when either water is injected till abandonment conditions or stopped at breakthrough depending on the richness of gas. The importance of mobilizing the trapped gas to de-pressurize the reservoir was also discussed. In this thesis, total liquid recovery was increased to 83% from 38% by injecting water throughout the producing life and gas recovery was increased to 94% from 71% by injecting water till water breakthrough. It was also found that for the base case which is only slightly under saturated, the water influx from aquifer is not as helpful as water injection because water influx occurred after pressure has been dropped in the reservoir and liquid has been condensed.

# Acknowledgments

I am extremely grateful to my supervisor Professor Curtis H. Whitson for providing me an opportunity to work under his guidance. His support, valuable suggestions and critical analysis throughout the thesis and project work have encouraged me to study hard and have really enhanced my learning capabilities. Working with him is really an amazing experience.

I want to extend my gratitude to NED University of Engineering & Technology, Karachi for trusting me and providing me financial support to pursue a master degree in Norwegian University of Science and Technology, NTNU.

I also like to thank International Office, NTNU for giving me an opportunity to study in the renowned University.

Special thanks to Brian Coats from Coats Engineering for providing me SENSOR software.

Many thanks to IPT office staff members for helping us in administrative affairs. I also like to thank my fellow students at IPT for keeping up an excellent friendly learning environment.

I present my sincere gratitude to my parents who are always a source of motivation and inspiration to me. Without their un-conditional love and support, I am nothing. I dedicated my degree to them.

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# 1 Introduction

The possibility of losing valuable liquid and lower gas well deliverability have made gas condensate reservoirs very important and extra emphasizes are made to optimize hydrocarbon recovery from a gas condensate reservoir. Methods like methanol treatments, wettability alteration and hydraulic fracturing are done to restore the well deliverability by removing or by passing the condensate blockage region. The above mentioned methods are applied in the near wellbore region and only improve the well deliverability temporarily while gas deliverability is maintained permanently by maintaining reservoir pressure above the dewpoint pressure by injecting fluid-traditionally produced gas.

The injection gas displaces the original reservoir gas miscibly towards the producing well while maintaining the reservoir pressure but, injecting produced gas back into the reservoir delays its sale. The ever increasing demand of hydrocarbon gas has caused the option of sale gas as an injected fluid to maintain the reservoir pressure to get un-economical to the operators.

Despite the fact that water is cheap and technology is available and well understood, water injection to maintain the reservoir pressure is generally not accepted for gas-condensate reservoirs because of the well known fact that significant amount of gas can be trapped in the reservoir. The experimental studies have indicated that as much as 50% of original gas in place is trapped in the reservoir because of water invasion[1]. Moreover, well lift can also be a severe problem if there are high water cuts during production. However, water injection has following advantages over gas injection: there is no delay in gas sale, the water injection costs are lower than gas injection, and the mobility of water is much lower than gas and may result in high sweep efficiency[2]. Moreover, water is not miscible with gas so dew point pressure of the reservoir fluid does not change. Therefore, by designing an optimum water injection rate and period of water injection, not only the ultimate liquid recovery can be improved but reservoir can be effectively de-pressurized to reduce the trapped gas at abandonment conditions.

If natural water aquifer is present, there may not be any need to inject any fluid (gas/water) into the reservoir for pressure maintenance. It depends on the size and strength of the aquifer and under saturation of the reservoir fluid. If aquifer is limited and pressure support is necessary, water can be injected directly into the aquifer zone at high rates. However, once water broke into the production well, the production well may need to be shut because of high water production at higher reservoir pressure. Therefore, the proper development plan is necessary to optimize ultimate recoveries from a particular water drive gas condensate reservoir. The designing variables include: gas rate selection and/or co-production of water from water production well and timing of co-production of water with respect to gas production. The goals are to initially maintain the reservoir pressure to ensure maximum liquid production and reduce the trapped gas volume at abandonment conditions.

The objective of this thesis is to investigate the feasibility of water invasion in gas condensate reservoir using simulation models. Sensitivity of various variables is also included in the study. Radial compositional model is used to study the water influx while coarse grid Cartesian compositional model is used to study the water injection performance. The effect of capillary forces and velocity dependent relative permeability is not considered in this thesis.

# 2 Technical Background

## 2.1 Introduction

Gas condensates reservoirs are special type of gas reservoirs which are often discovered as gas phase, but have liquefiable components dissolved in the gas phase which are separated as liquid at surface conditions and when reservoir pressure falls- due to production of reservoir fluid, below the dew point pressure, these liquefiable components begins to condense from gas in the reservoir. Depending upon the richness of the reservoir fluid, the amount of condense liquid can be very high-as much as 50%, especially near wellbore where pressure is at it's minimum in the reservoir. This isothermal condensation of liquid from gas in the reservoir is termed as retrograde condensation. Much of the liquid dropped in the reservoir does not flow and is considered as lost. If this liquid does not condense in the reservoir, it is eventually produced at surface along-with gas and constitutes a major portion of revenue for the company. Moreover, condense liquid restricts the flow path of gas and hence educes the gas deliverability which further decreases company's revenue.

Gas Condensate reservoirs with large variations in initial reservoir temperature, pressure and composition have been discovered[3]. Most known retrograde gas-condensate reservoirs are in the range of 5000 to 10000 ft deep, at 3000 psi to 8000 psi and a temperature from 200 F to 400 F. The initial condensate-gas ratio (inverse of gas-oil ratio) is the measure of the richness of the gas condensate fluid and gas condensate typically has about 5 to 350 STB of oil per million standard cubic feet (MMscf) of gas and liquid gravities between 40 and 60 API[4]. High CGR means more money and therefore required proper attention during development.

## 2.1 Composition of Gas Condensate Reservoir Fluid

Gas condensate reservoirs have more heavy components than conventional gas reservoir and less heavy components than black oil and volatile oil reservoir. The molar % of heptane plus in gas-condensate can be high as 12.5%. Table 2.1 compares the composition of different reservoir fluids.

*Table 2.1: Composition of different reservoir fluids [from whitson[4]].*

| Components | Black Oil (mol %) | Volatile Oil (mol %) | Gas Condensate (mol %) | Wet Gas (mol %) | Dry Gas (mol %) |
|---|---|---|---|---|---|
| C1 | 34.62 | 58.77 | 73.19 | 92.46 | 86.12 |
| C2 | 4.11 | 7.57 | 7.80 | 3.18 | 5.91 |
| C3 | 1.01 | 4.09 | 3.55 | 1.01 | 3.58 |
| i-C4 | 0.76 | 0.91 | 0.71 | 0.28 | 1.72 |
| n-C4 | 0.49 | 2.09 | 1.45 | 0.24 | - |
| i-C5 | 0.43 | 0.77 | 0.64 | 0.13 | 0.50 |
| n-C5 | 0.21 | 1.15 | 0.68 | 0.08 | - |
| C6 | 1.61 | 1.75 | 1.09 | 0.14 | - |
| C7+ | 56.40 | 21.76 | 8.21 | 0.82 | - |

## 2.2 Phase Behavior Diagram of Gas Condensate

Phase behavior of gas condensate reservoir fluid can be understood by P-T (pressure-temperature) diagram-figure 2.1. The P-T diagram has a bubble point line (the first bubble of gas liberates from the oil) and a dew point line (first drop of liquid condenses from the gas). Both bubble point and dew point line meet at critical point-the conditions where it is difficult to differentiate between liquid and gas phases. The temperature and pressure at critical point are called critical temperature and pressure respectively. The maximum temperature of the P-T diagram is called cri-condentherm.

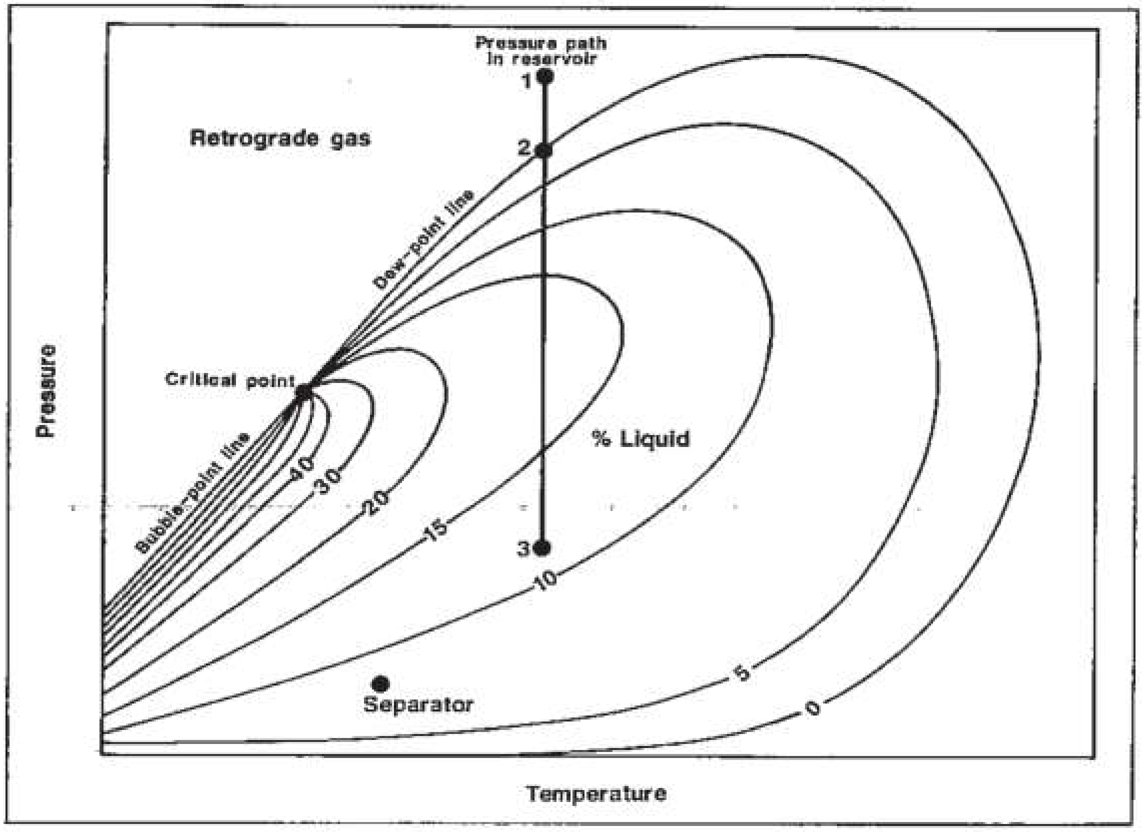


*Figure 2.1: Typical phase diagram of a gas condensate [from McCain[5]].*

The initial reservoir temperature of the gas condensate reservoir fluid is between critical temperature and cri-condentherm. The initial reservoir pressure can be equal to or higher than dew point pressure of reservoir fluid. The position of initial reservoir temperature classifies the gas condensate as either rich or lean. As reservoir is produced, initial pressure will start to decrease and the reservoir fluid will reach to its dew point conditions-if original fluid is under saturated, and liquid will start to condense from the gas and two-phase will form in the reservoir.

The mobility of this condensed liquid is low because of high viscosity and interfacial tension and most of this condense liquid will not flow into the well bore-except for liquid dropped in small area near wellbore, and will eventually be lost in the reservoir. Therefore, most of produced oil at surface is the oil that was dissolved in the gas at reservoir condition. As oil is more valuable than gas, net present value for well/field is decreasing as oil is being left into the reservoir.

The reservoir gas is getting leaner below dew point and will bring less liquid to the surface. As reservoir pressure continuously decreases, more and more liquid will condenses from the gas and liquid saturation in the reservoir will reach to maximum limit. Moreover, as most of the condensed oil is not flowing, so producing gas oil ratio will increase below the dew point. Sharp increase in producing gas oil ratio indicates that oil is being condensed from the gas very quickly and it is generally for rich gas condensate reservoir. The ultimate oil recovery for such scenario will also be low as except for the small percentage of oil that condenses out near the wellbore, the majority portion of the oil that condenses from the gas in the reservoir will not flow into the wellbore and is considered as lost. If pressure decreases further due to production, condense liquid will again be re-vaporized into gas phase but this situation seldom happens as phase diagram is continuously changing below dew point pressure and two phase condition exists at all time.

## 2.3 Condensate Blockage/Importance of Maintaining Reservoir Pressure

If well flowing pressure is less than the dew point pressure, the fluid flow towards the well in a gas condensate reservoir during depletion develops following three regions[6]:

### 2.3.1 Region 1

This region is near well bore, and saturation of the condensed liquid is higher than the critical saturation so both gas and condensate are flowing. As saturation of gas is lower in this region, relative permeability of gas is also lower and gas productivity may be severely lost. Relative permeability at a particular saturation of gas may somewhat increase if gas rate is sufficiently high rate but will still be lower than if no condensate was dropped in this region. The gas coming from region 2 into region 1 will have less dissolved liquid as was present originally and producing oil gas ratio will be at lower level. The pressure at the boundary between region 1 and 2 is calculated through the composition of the producing well stream.

### 2.3.2 Region 2

The pressure in this region is still lower than the dew point pressure, and condensate is being dropped from the reservoir gas but the critical saturation of condensate has not been reached and only gas is flowing in this region. The condensate saturation in this region is increasing from 0% at the boundary of region 3 to critical saturation at the boundary of region 1. The gas is getting leaner as heavier components are being dropped from the original gas. This lean gas will move to region 1 and will eventually be produced at the well.

### 2.3.3 Region 3

The pressure in this region is higher than dew point pressure and only original reservoir gas is present. Obviously, the size of region 3 will shrink as production from reservoir continues. When reservoir pressure falls below the dew point pressure, liquid will dropped from the gas in the bulk of the reservoir and only region 1 and 2 will exists.

Region 1 and region 2 are called blockage region as mobility of gas in these regions is lowest in the system. These regions behave like damaged zone and provide an additional pressure drop in the flow of gas resulted in lower productivity of gas and depending on reservoir permeability and richness of gas, the damage can be severe. Moreover, these regions may contain significant valuable liquids and oil production rate may decrease when these regions begin to build in the reservoir. As has been explained above, much of the condensed liquid does not flow and considered as lost. Even for lean gas condensate, it has been shown that saturation of condensate drop near wellbore can be very large as quite number of pore volume of gas passes through this region leaving behind the condensate dropped[7].

Afidick et al[8]. presented the case history of arun field in Indonesia having lean reservoir fluid with maximum liquid drop out of 2%. They show that liquid dropout near wellbore as pressure declined below dew point has resulted in upto 50% decline in productivity of the gas as liquid accumulation severely restrict the flow of gas. This emphasizes the importance of keeping the pressure above dew point pressure to maintain the productivity of gas as decline in productivity of a particular well eventually leads to drill more wells to meet the desired field production rate.

Engineer[9] discussed the performance of a tight abnormal pressured rich gas condensate reservoir of the Cal Canal Field in California which had 59% initial water saturation. The total gas recovery from the field was expected to be 10% of Original gas in place (OGIP) because of the high condensate and water saturation in the near wellbore region. Moreover, the abandonment average reservoir pressure was expected to be quite high-5835 psig, because of high connate water saturation and condensate saturation which were acting as a damaged zone.

Barnum et al.[10] performed depletion studies on various gas condensate reservoirs and showed that loss in gas deliverability due to condensate build up near wellbore is much severe for low-permeable reservoirs than for high permeable reservoirs.

Because of these reasons, maintaining the producing gas oil ratio to its original value or delay in increase of producing gas oil is a primary concern in developing gas condensate reservoirs. As mentioned above, keeping the gas-oil ratio to its original value will not only increase the liquid recovery but gas deliverability will also be maintained and well/field can deliver plateau gas production rate for longer period of time.

Producing gas oil ratio is maintained by keeping the pressure of the reservoir above dew point pressure and is done by injecting some fluid into the reservoir-traditionally produced gas back. Sergey Kolbikov[11] expressed the importance of injection in gas-condensate reservoirs by mentioning that in USA, the ultimate depletion condensate recovery is around 30-60% of original condensate in place (OCIP) while by doing gas-cycling the condensate upto 88% of OCIP have been recovered.

## 2.4 Water Influx

Reduction in reservoir pressure due to production from a gas condensate reservoir causes water from aquifer to invade into the pay zone if water aquifer is in communication with pay zone. The influx of water supports the pressure and maintains the well deliverability at higher level than depletion case. The pressure support from aquifer depends on aquifer size, aquifer permeability, initial reservoir pressure and water and rock compresibilities[12].

Permeability is the most important parameter which determines whether there is any time delay between gas production and water support. Obviously if aquifer permeability is very low, the effect of aquifer may not be seen, and reservoir will behave like there is no aquifer present beneath reservoir.

Too much water from an active aquifer results in early abandonment of the gas reservoir and trapping of large amount of gas. Figure 2.2 is typical graph between p/z and recovery for a gas reservoir under different support from aquifer.

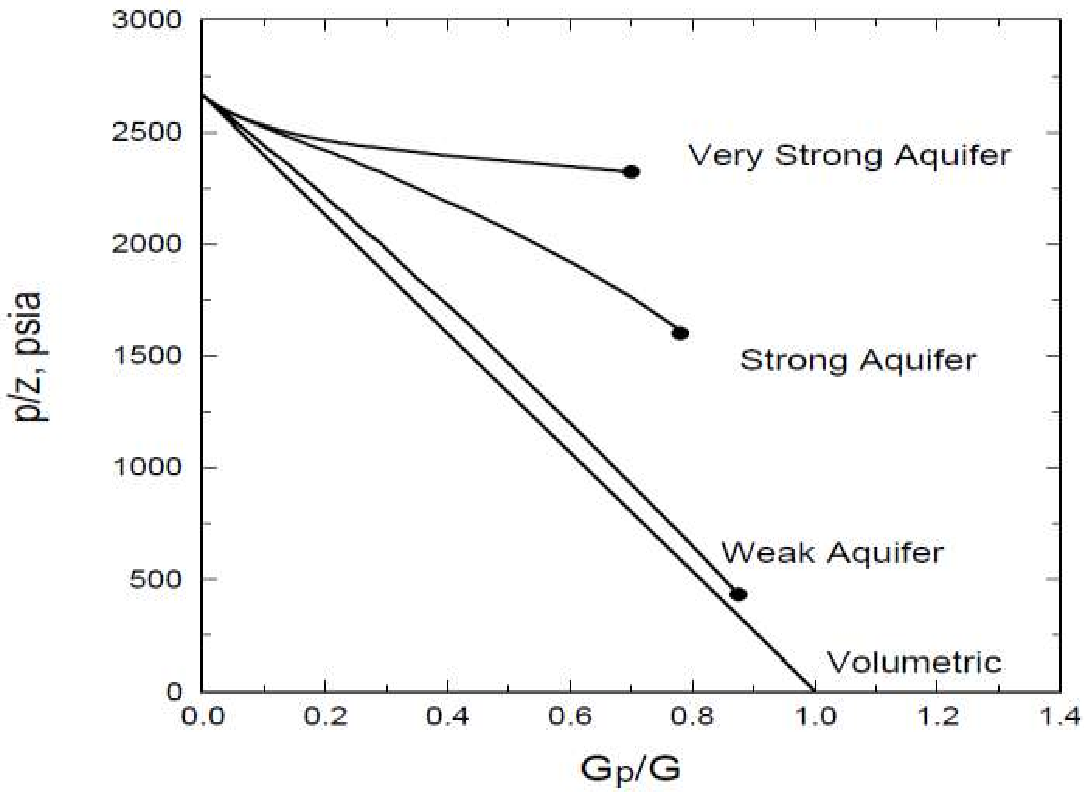


*Figure 2.2: p/z vs Gp/G graph for various strength of water drive [after fevang[12]].*

Agarwal et al.[13] described the dependence of gas recovery under water influx on various factors including: production rate and manner of production, the residual gas saturation, aquifer properties and the volumetric displacement efficiencies. They showed that gas recovery can be significantly increased by early characterization of water influx.

Matthews et al.[14] discussed the importance of rapid de-pressurization of the gas reservoirs to re-mobilize the trapped gas during water influx and mentioned that trapped gas upto 10% of original gas in place (OGIP) can be re-mobilized by rapid de-pressurization.

Hower et al.[15] showed through simulation study that production at low gas rate from water drive gas reservoir increases volumetric sweep efficiency then accelerated gas production and thus results in higher gas recovery. Accelerated gas production in their simulation models resulted in early water break through and large trapping of gas. They also discussed the importance of co-production of water to improve gas recovery.

## 2.5 Water Injection

If the size of the aquifer is low and reservoir fluid is only slightly under saturated, water can be injected into the reservoir instead of produced gas to maintain the reservoir pressure above dew point to avoid dropping of liquid from gas. With water injection, not only produced gas can be sold immediately but, the operating cost of water injection is low. However, pre-mature shut-in of production well due to large production of water with large trapping of gas at higher abandonment pressure have always restricted the widely use of water injection into gas condensate reservoirs. This large production of water can also create well lift problems but favorable mobility ratio with water injection may provide high sweep efficiency. The other technical factors that need to be considered for enhancing volumetric sweep efficiency of any waterflooding project are: injection rate, reservoir heterogeneity, viscosity, well spacing, reservoir permeability and dip of the reservoir.

McCain et al.[2] demonstrated that water injection is a feasible option for enhancing recoveries from gas condensate reservoirs. They emphasized that for an effective water flooding project, the injection of water should be stopped before water broke through the production wells to re-mobiliz the trapped gas.

Fisholk et al.[16] performed waterflooding studies on North Sea gas condensate reservoirs. They used the modified relative permeability data during the pressure depletion period after water injection as trapped gas does not start to flow immediately during depressurization period and saturation of gas has to increase significantly by expansion in order to flow. They also studied the effect of condensed oil on trapped gas saturation during waterflooding and critical gas saturation during de-pressurizing period and concluded that condensed oil reduces both trapped and critical gas saturation.

Henderson et al.[17] performed experimental study to understand waterflooding in gas condensate reservoirs and have reported that during blow down period the trapped gas has to expand considerably in order to get re-mobilize again-further strengthen the conclusions of Fisholk et al[15]. Moreover, during blow down period, the dropped condensate did not flow and distribute into tight capillaries and thick film on pore walls. They also mentioned that at re-mobilization, the relative permeability of gas and condensate appeared to be greatly reduced.

Henderson et al.[18] also showed through experiments that the lowest residual condensate saturations were achieved when water invasion occurred above the dew-point. They also suggested that in order to increase condensate recovery water invasion should be done above the dew point pressure.

Cason[19] has reported a case history of a southern Louisiana gas reservoir in which recovery from a low pressure gas reservoir has been increased by waterflooding. The water was injected at abandonment conditions which had displaced residual gas-3.6 % of OGIP. He also mentioned that waterflooding in volumetric reservoir can increase gas recovery upto 16% of OGIP.

# 3 Development of Simulation Model

## 3.1 Model Description

This simulation study has been done using Coats engineering simulation software SENSOR. The data for this study are taken from third SPE comparative solution Project[20]. The Cartesian model in third SPE Comparative Solution Project has total 144 grids-9, 9 and 4 grids in x, y and z directions respectively. The reservoir is 160 ft thick and gas-water contact is at 7500 ft. The layers are homogeneous and have constant porosity of 13%, but permeability and thickness vary among layers. Table 3.1 gives the permeability and thickness of each layer.

*Table 3.1: Pemeabilities and thicknesses of layers.*

| **Layer** | **Horizontal Permeability (mD)** | **Vertical Permeability (mD)** | **Thickness (ft)** |
|---|---|---|---|
| 1 | 130 | 13 | 30 |
| 2 | 40 | 4 | 30 |
| 3 | 20 | 2 | 50 |
| 4 | 150 | 15 | 50 |

The initial pressure is 3550 psia at the depth of 7500 ft. Other data, used in simulation model, is given in table 3.2.

*Table 3.2: Reservoir, well, fluid and production data used in simulation model.*

| | |
|---|---|
| Initial reservoir pressure (psia) | 3550 |
| Gas-water contact (ft) | 7550 |
| Connate water saturation (%) | 0.217 |
| Water density (lb/ft$^3$) | 63 |
| water compressibility (1/psi) | 3.0E-06 |
| Rock Compressibility (1/psi) | 4.0E-06 |
| Rate (Mscf/d) | 6200 |
| radius of well (ft) | 1 |
| Minimum bottom Hole Pressure (psia) | 1000 |

## 3.2 Reservoir Fluid

The reservoir fluid is a moderate rich condensate fluid with maximum liquid drop out is around 20% at 2400 psig. The initial condensate to gas ratio is 138 STB/MMscf. The original reservoir fluid consists of 59% gas and 41% liquid by mass at surface and from these figures, the importance of maximizing the liquid recovery is again emphasized. The dew point pressure is 3450 psia-just only 100 psia below the reservoir pressure. As dew point pressure is near to the original reservoir pressure, the pressure maintenance program at early stage of production is needed to avoid loss of valuable condensate.

Fevang et al.[21] have compared performance of gas condensate and volatile oil reservoir with black oil and compositional models under different development schemes. They reported that depletion performance of a gas condensate reservoir can be effectively predicted by black oil models but for gas injection below dew point pressure compositional models are recommended. In this thesis, although the computational time for compositional model is higher than black oil model, the compositional model has been used to effectively capture the mass transfer between the injected/encroach fluid and reservoir fluid-if any.

In this study, the Equation of State (EOS) developed by Arco Oil and Gas Company is used to define the fluid behavior. The EOS has nine components and details of the EOS are given in table 3.3 and 3.4.

*Table 3.3: EOS used in simulation.*

| Component | Critical Pressure (atm) | Critical Temperature (K) | Molecular Weight | Arsenic Factor |
|---|---|---|---|---|
| CO2 | 1070.7 | 547.58 | 44.01 | 0.225 |
| N2 | 491.68 | 227.29 | 28.02 | 0.04 |
| C1 | 670.1 | 335.9 | 16.04 | 0.013 |
| C2 | 707.79 | 549.59 | 30.07 | 0.098 |
| C3 | 616.41 | 665.73 | 44.1 | 0.152 |
| C4-6 | 498.2 | 713.2 | 67.28 | 0.234 |
| C7P1 | 376.2 | 1030.5 | 110.9 | 0.332 |
| C7P2 | 245.4 | 1134.4 | 170.9 | 0.495 |
| C7P3 | 124.9 | 1552.7 | 282.1 | 0.833 |

*Table 3.4: Binary interaction coefficients to improve EOS calculations.*

**Binary Interaction Coefficients**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| CO2 | 0.02 | 0.1 | 0.13 | 0.135 | 0.1277 | 0.1 | 0.1 | 0.1 |
| N2 | 0.036 | 0.05 | 0.08 | 0.1002 | 0.1 | 0.1 | 0.1 | |
| C1 | 0 | 0 | 0.09281 | 0 | 0 | 0.1392 | | |
| C2 | 0 | 0 | 0.00385 | 0.0063 | 0.006 | | | |
| C3 | 0 | 0.00385 | 0.0063 | 0.006 | | | | |
| C4-6 | 0 | 0 | 0 | | | | | |
| C7P1 | 0 | 0 | | | | | | |
| C7P2 | 0 | | | | | | | |
| C7P3 | | | | | | | | |

## 3.3 Relative Permeability

The relative permeability data given in the third SPE Comparative Solution Project can directly be used in the simulation model but in this study, relative permeability data have been entered using Corey power-law relative permeability correlation such that relative permeability values predicted from the correlation gave the same values as reported value. The Corey correlation for calculating oil and gas relative permeability is given by

$$k_{rog} = k_{ro}(S_{wc}) * \left(\frac{1 - S_{org} - S_g - S_{wc}}{1 - S_{org} - S_{wc}}\right)^{n_{og}} \tag{1}$$

$$k_{rg} = k_{rg}(S_{org}, S_{wc}) * \left(\frac{S_g - S_{gc}}{1 - S_{org} - S_{wc} - S_{gc}}\right)^{n_g} \tag{2}$$

Where

$k_{rog}$= Oil relative permeability to gas
$k_{rg}$= Gas relative permeability
$k_{ro}(S_{wc})$ = Oil relative permeability at connate water saturation
$k(S_{org}, S_{wc})$ = Gas relative permeability at residual oil saturation and connate water saturation
$S_{org}$= Residual oil saturation to gas
$S_g$ = Gas saturation
$S_{gc}$ = Critical gas saturation
$n_{og}$ = Oil relative permeability exponent
$n_g$ = Gas relative permeability exponent

Figures 3.1 and 3.2 compare the results from the Corey correlation to reported data

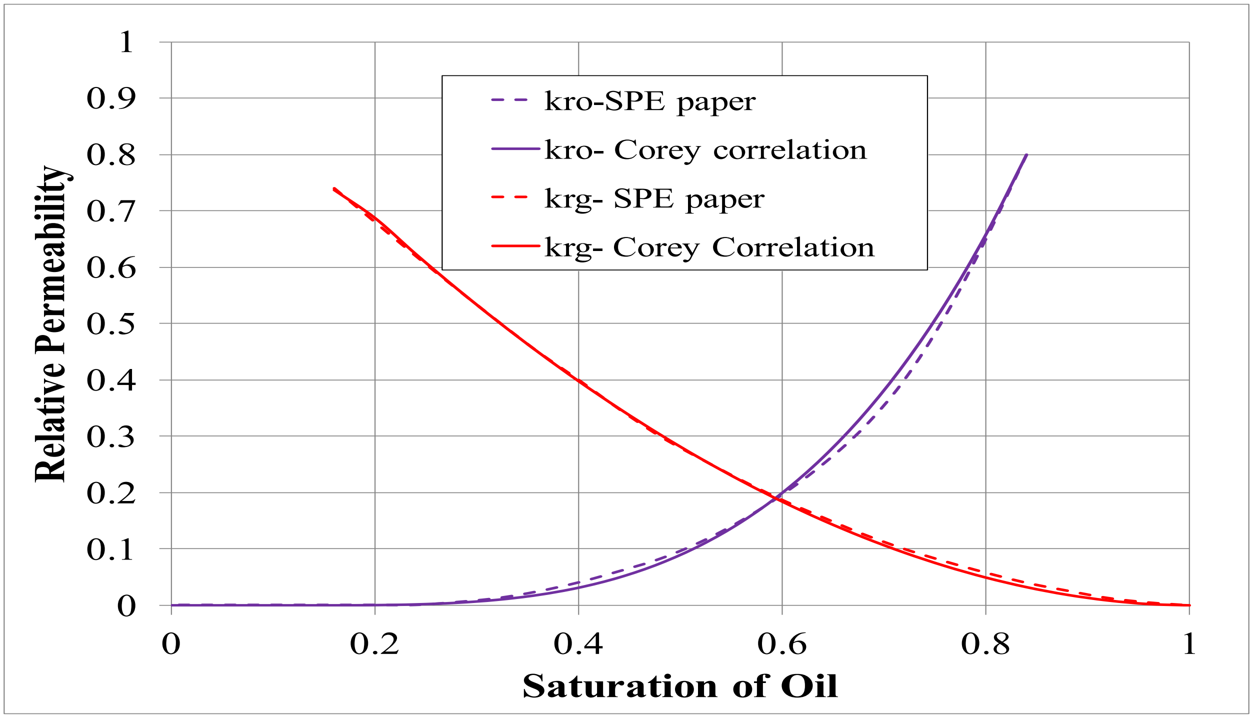


*Figure 3.1: Gas-oil relative permeability curve.*

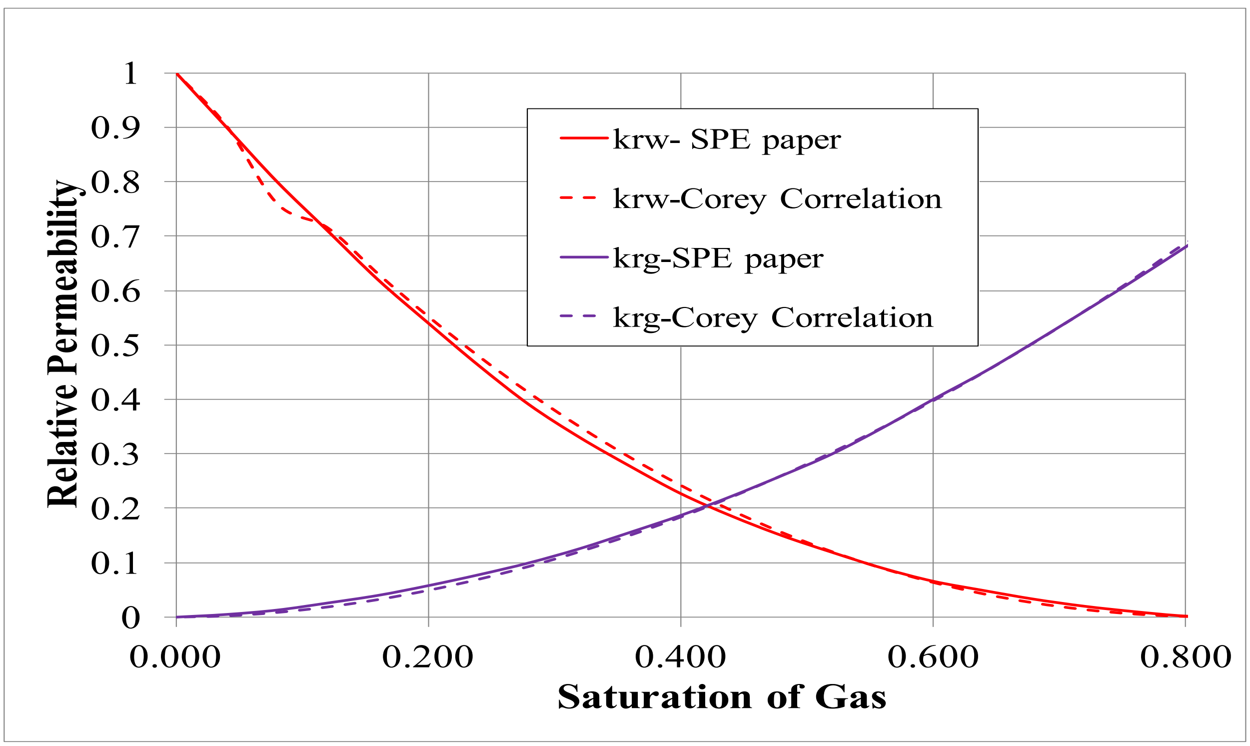


*Figure 3.2: Gas-water relative permeability curve.*

The final values of the variables used in Corey correlation for the best fit curves are given in table 3.5.

*Table 3.5: Corey correlation variable used in simulation model.*

| | | | | |
|---|---|---|---|---|
| 0.16 | 0 .3 | 0.124 | 0.0 | ! $S_{wc}$ $S_{orw}$ $S_{org}$ $S_{gc}$ |
| 0.380 | 0.556 | 0.8 | | ! $k_{rw}$(Sorw) $k_{rg}$(Swc,Sorg) $k_{ro}$(Swc) |
| 2.2 | 2.8 | 1.9 | 3.4 | ! $n_w$ $n_{ow}$ $n_g$ $n_{og}$ |

## 3.4 Surface Conditions

An efficient ideal separation at the separator is assumed-sell gas has all $C_{4-}$ and liquid has all $C_{5+}$. This simplified assumption excludes the effect of separator pressure and temperature on the recovery of oil and gas.

## 3.5 Radial Model

The Cartesian model was converted to an equivalent radial model. Radial model is selected because in radial model grid blocks are finer near wellbore and increase with distance and it's suitable for understanding condensate dropout and water coning. The radial model has 36 grids, 9, 1 and 4 grids in radial, angular and vertical direction respectively. Before adding aquifer, the depletion performance of both Cartesian and Radial model was compared. The production well was placed in the center of both models and, all other parameters were also same. The results are shown in figures 3.3 and 3.4.

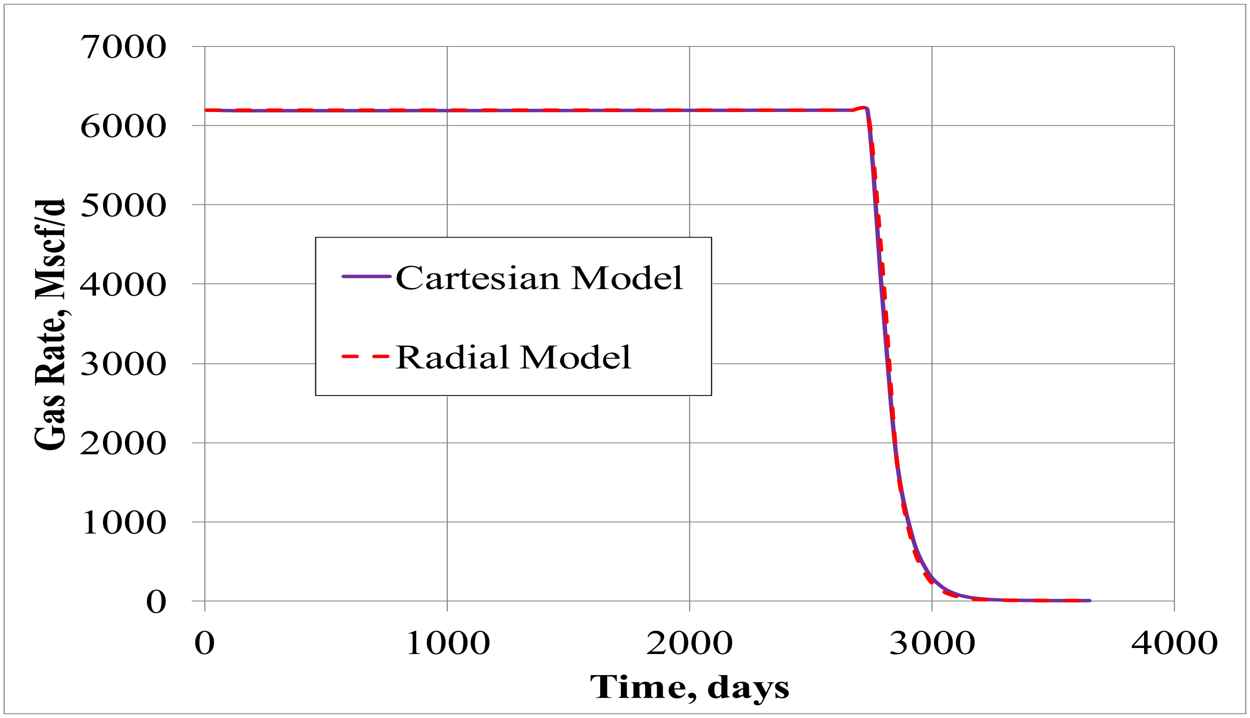


*Figure 3.3: Gas rate comparison of cartesian and radial model.*

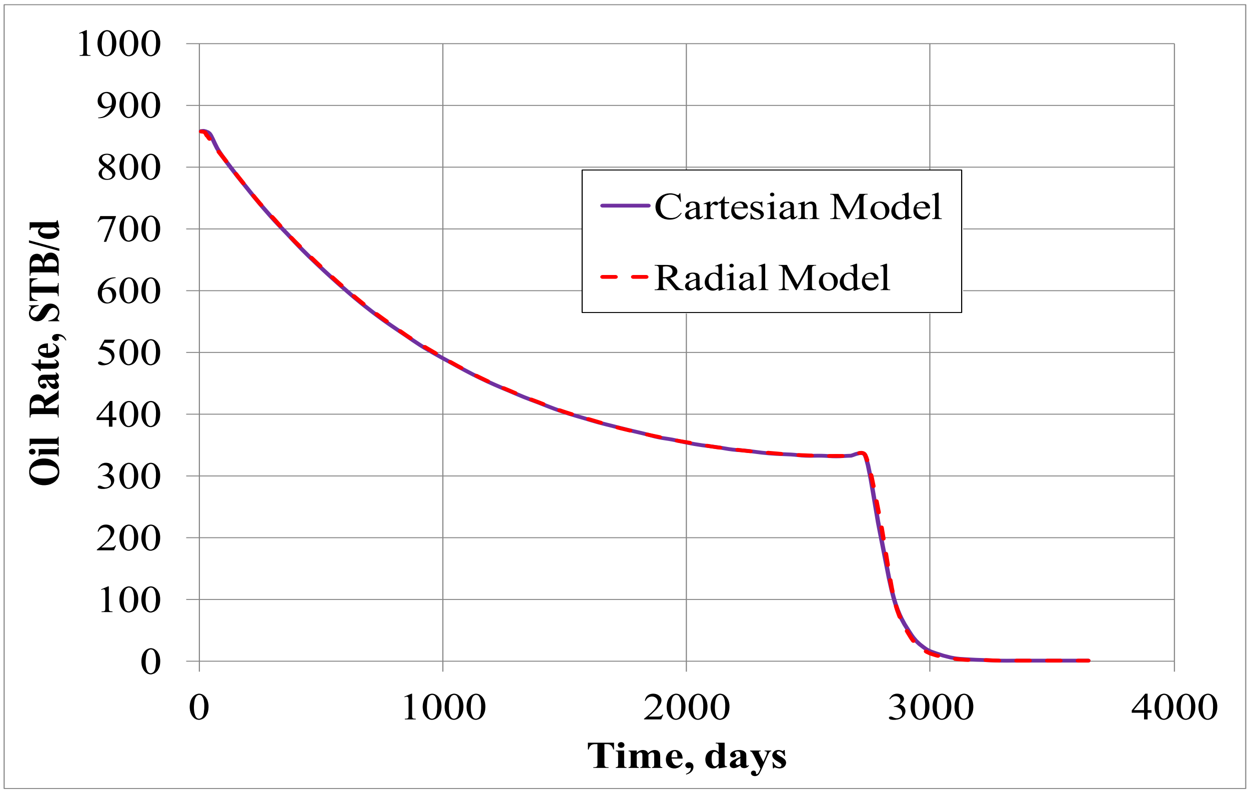


*Figure 3.4: Oil rate comparison of cartesian and radial model*

The results confirmed that developed radial model is representative of the Cartesian model given in third SPE comparative solution project and can be used for further studies.

## 3.6 Grid Refinement

Selection of optimum size of grid block is very important. Grid blocks should be small enough to efficiently capture the effect of rapid changes occurring in flow properties near wellbore and large enough to have accepted computing time.

Singh et al.[22] discussed the need of fine gridded simulation model for gas condensate reservoir by comparing the fine gridded and coarse gridded performance of a gas condensate reservoir under different operating conditions. They concluded that without pseudo pressure option, the coarse grid model gives optimistic results and is not sufficient to capture the condensate drop out effect.

To capture the effect of condensate dropout near the wellbore, grid refinement was done and the performance of a volumetric gas condensate reservoir was compared under various refined grids. Refinement was done both in radial and vertical direction. Figures 3.5 and 3.6 show that the performance of the volumetric gas condensate reservoir was quite independent of the grid refinement and it was quite surprising.

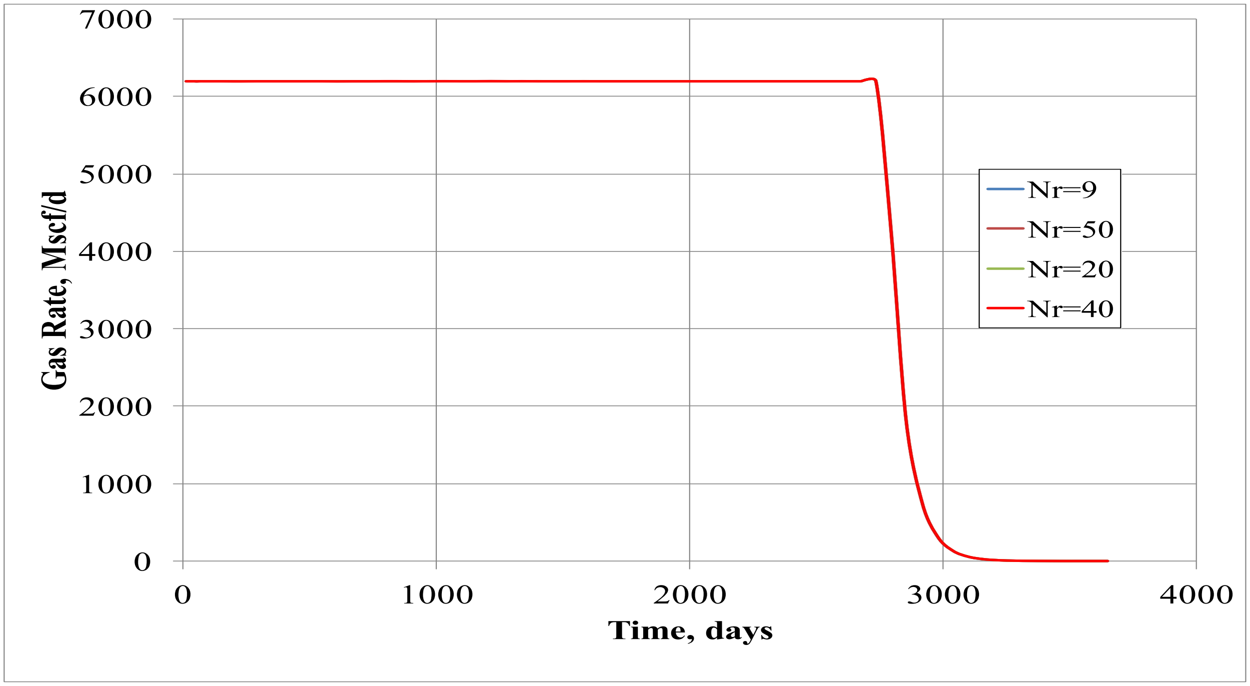


*Figure 3.5: Gas rate comparison for refinement in radial direction.*

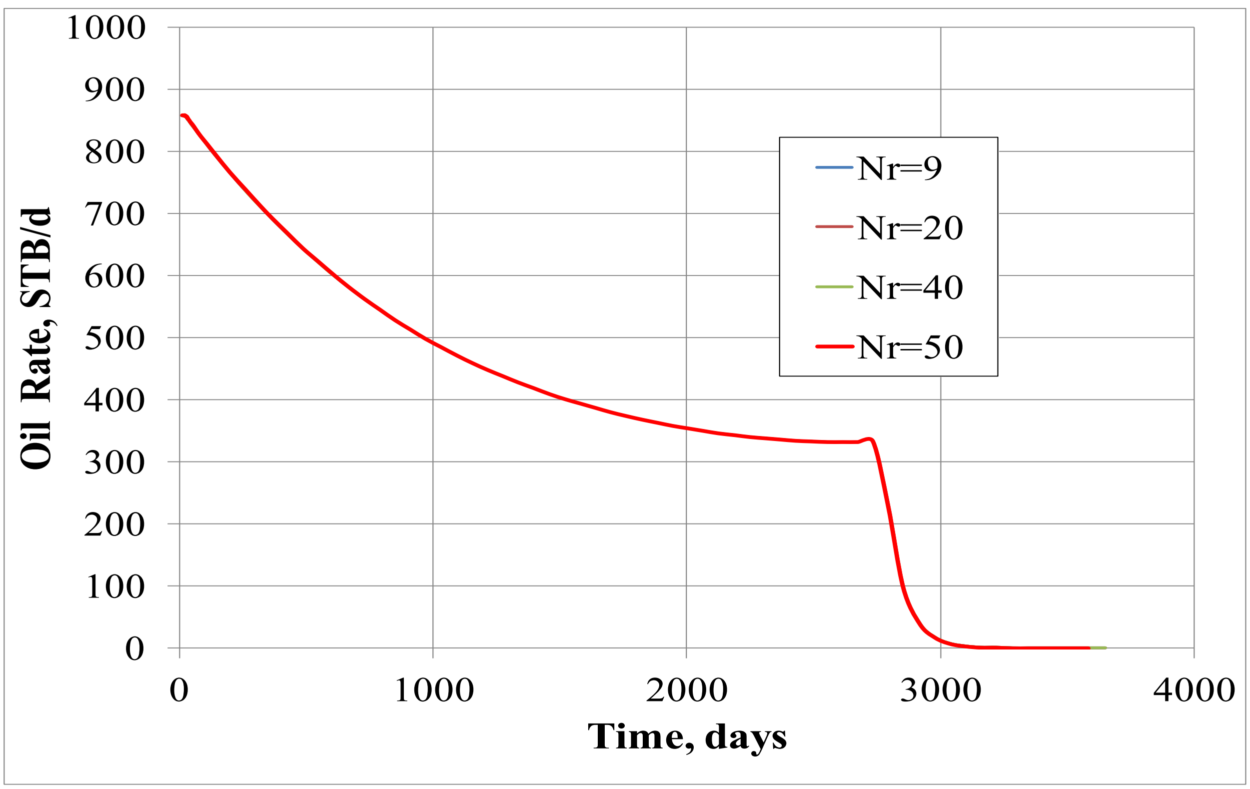


*Figure 3.6: Oil rate comparison for refinement in radial direction.*

Further investigations were done to determine whether refinement has any impact on the developed simulation model. Initially, reservoir permeability was decreased. At lower reservoir permeability, the performance of the reservoir changed with different grid sizes as shown in figures 3.7 and 3.8.

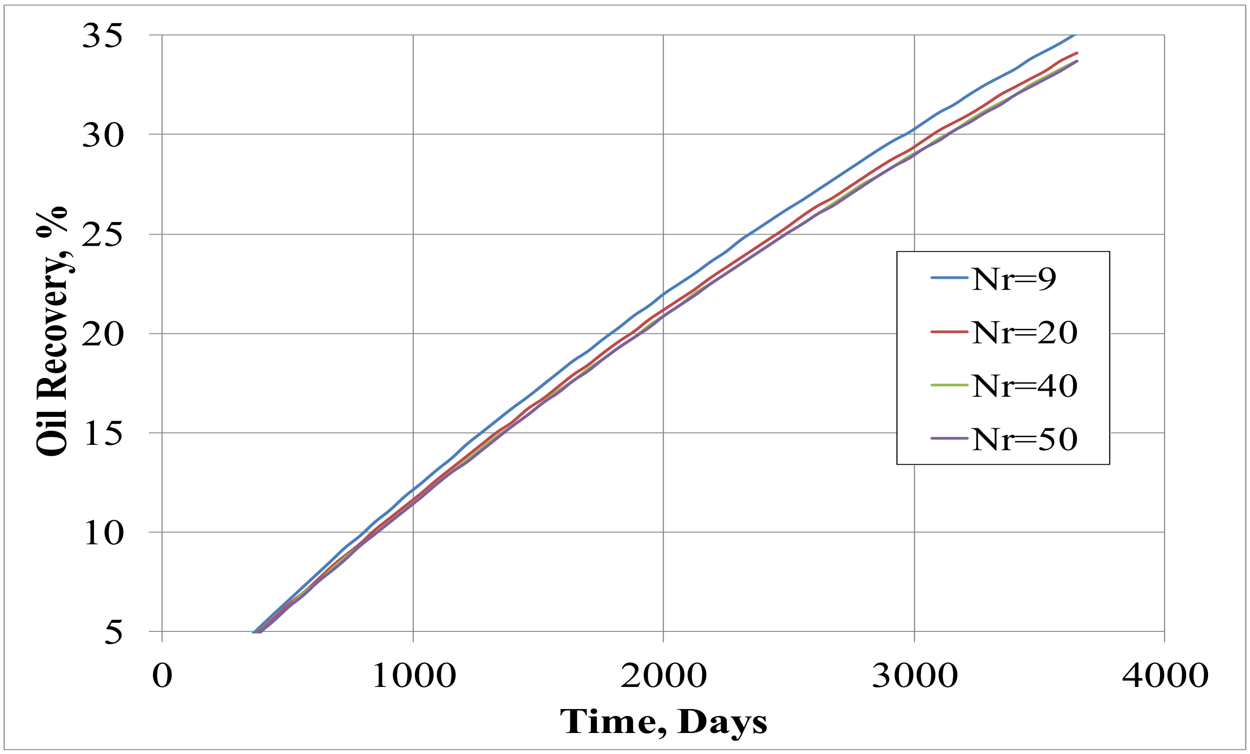


*Figure 3.7: Oil recovery comparison of low permeable reservoir (k=1 mD) for refinement in radial direction.*

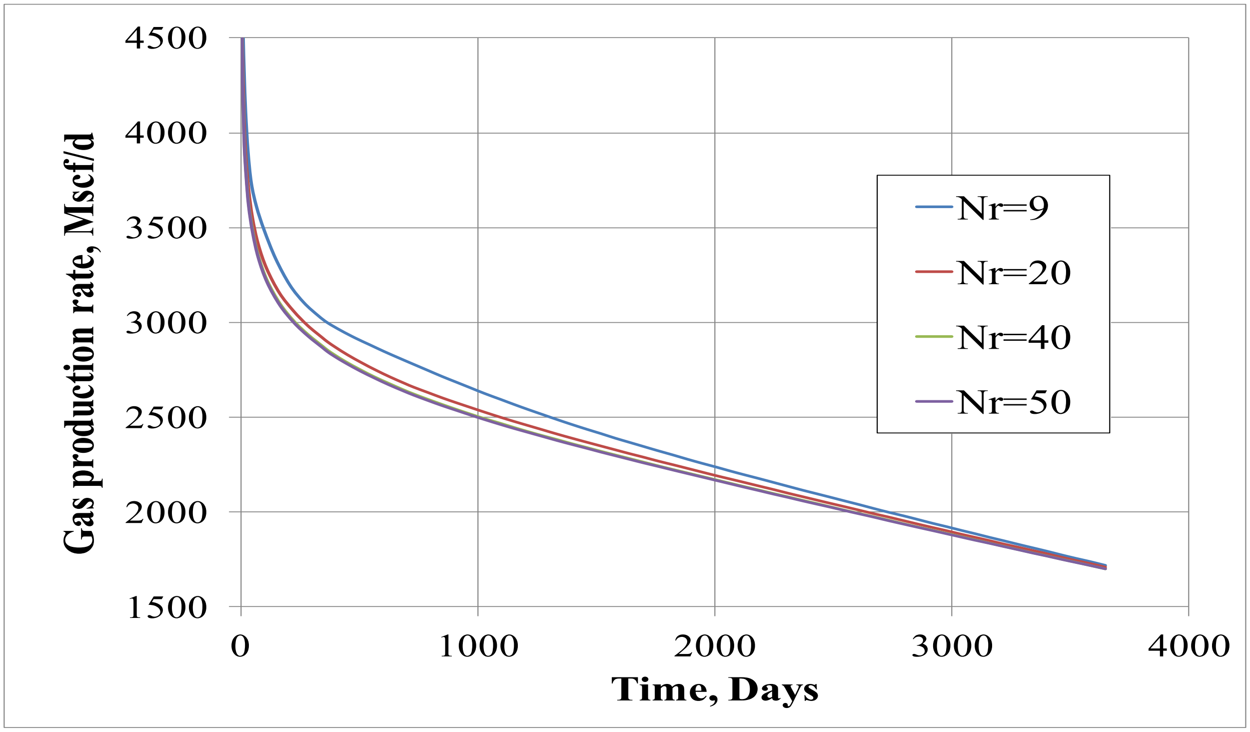


*Figure 3.8: Gas rate comparison of low permeable reservoir (k=1 mD) for refinement in radial direction.*

To further investigate the effect of grid refinement, compositional model in the base case was converted into black oil model, and instead of assuming idealistic surface condition-surface gas has all C4- and surface oil has all C5+, the three stage separator conditions are applied in the simulation model. Homogeneous reservoir with constant permeability of 100 mD was assumed. Results from this case are summarized in figures 3.9 and 3.10.

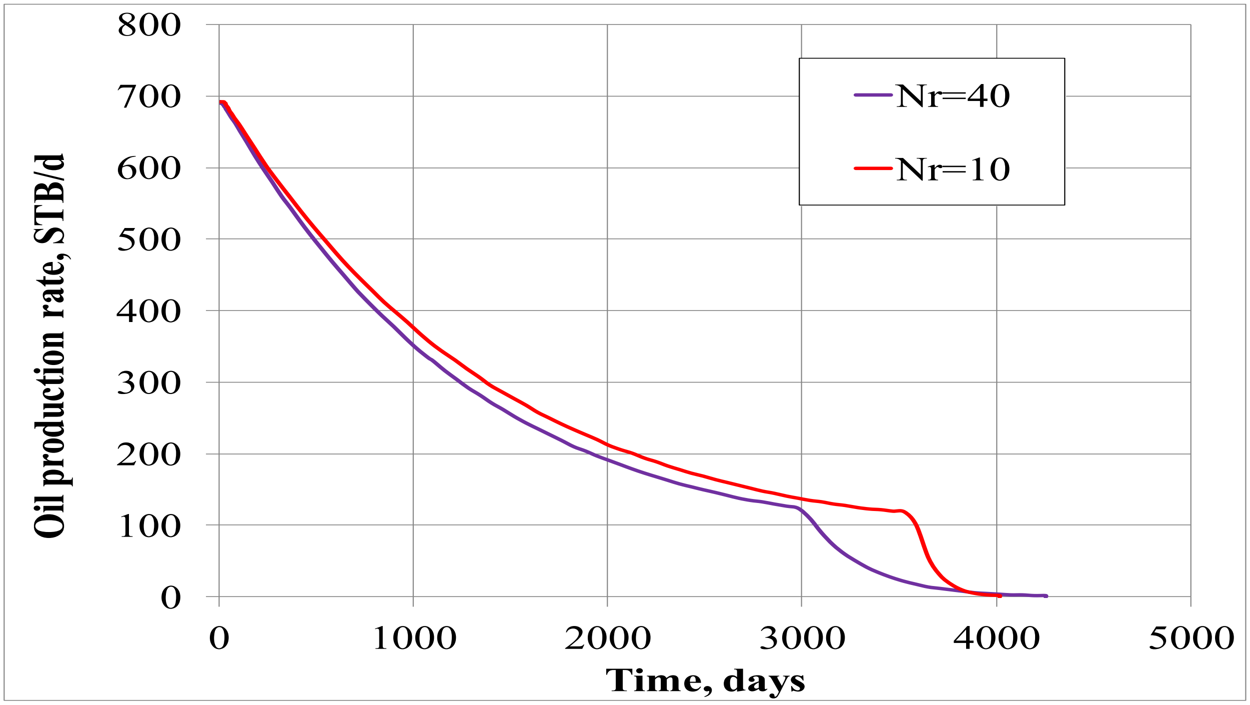


*Figure 3.9: Oil production rate comparison for different number of grids for radial black oil model with three stage separators.*

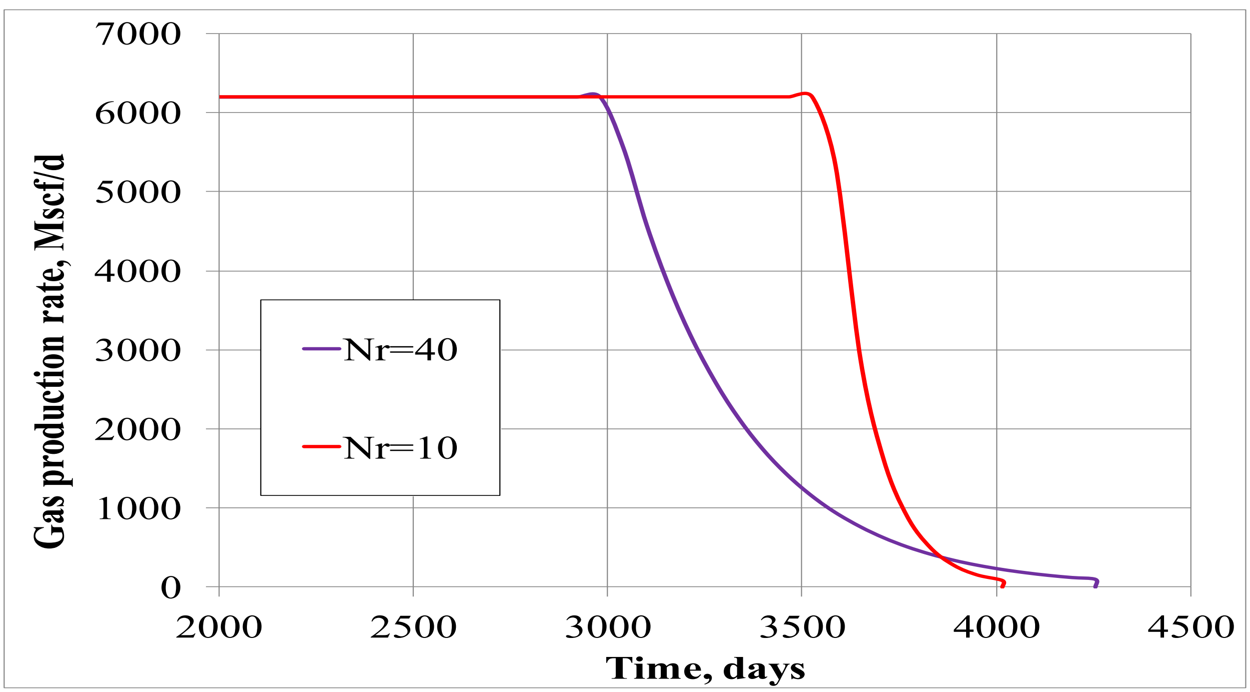


*Figure 3.10: Gas production rate comparison for different number of grids for radial black oil model with three stage separators.*

High permeability, compositional model and assumption of efficient separation in the base case have sufficiently captured effect of dropped condensate in the coarse grid model. Therefore the effect of refinement was not obvious.

As different cases are to be run for different reservoir and aquifer permeability, radial model with enough gridding was selected for the study. Refined model has 40 layers in radial directions and 12 layers in vertical direction in the pay zone. Table 3.6 summarizes the properties of layers of pay zone used in the refined model.

*Table 3.6: Thickness and permeability of each layer used in refined model.*

| Layer No. | Horizontal Permeability (mD) | Vertical Permeability (mD) | Thickness (ft) |
|---|---|---|---|
| 1 | 130 | 13 | 10 |
| 2 | 130 | 13 | 10 |
| 3 | 130 | 13 | 10 |
| 4 | 40 | 4 | 10 |
| 5 | 40 | 4 | 10 |
| 6 | 40 | 4 | 10 |
| 7 | 20 | 2 | 16.67 |
| 8 | 20 | 2 | 16.67 |
| 9 | 20 | 2 | 16.67 |
| 10 | 150 | 15 | 16.67 |
| 11 | 150 | 15 | 16.67 |
| 12 | 150 | 15 | 16.67 |

## 3.7 Aquifer Size and Strength

In this study, the aquifer of various size and strength is assumed. Size of aquifer is measured with respect to the size of reservoir and expressed by term M which is

$$\mathrm{M} = \frac{\text{Volume of Aquifer}}{\text{Pore Volume of Gas} - \text{Bearing Reservoir}} \tag{3}$$

The strength of aquifer is expressed with respect to its permeability and reservoir pressure. By increasing the aquifer permeability and/or reservoir pressure, the aquifer of good strength is assumed.

The size of aquifer is increased gradually by first adding layers of 20 ft in vertical directions in the simulation model until the size of aquifer is ten times that of size of reservoir. Then, vertical layers of 40 ft are added until the size of aquifer is twenty times that of size of reservoir. Further size of aquifer is increased by increasing the porosity of the grids in the furthest layers.

# 4 Aquifer Effect on Gas Condensate Reservoir Performance

## 4.1 Effect of Aquifer Size on Base Case-Original Heterogeneous Reservoir

In this case, the aquifer with almost same permeability as that of pay zone is assumed ensuring the vertical heterogeneity in the aquifer as that of pay zone-vertical permeability is ten times lower than horizontal permeability which is $k_z$=10 mD and $k_x$=100 mD. The input simulation file is given in Appendix A.

Two sub-cases were run-with and without surface limits of water production rate.

### 4.1.1 With Surface Limits

This is the realistic case in which two assumptions are made:

1) The maximum water production handling capacity from the well is 100 STB/d.
2) Minimum economical gas flow rate is 100 Mscf/d.

When water handling capacity limit is applied in the simulation model, layers which are producing large amount of water are automatically shut in. SENSOR is continuously applying the work-over processes to the reservoir to shut those layers which are producing large amount of water and , when all layers produces water above maximum water production limit, the well will be closed.

The recoveries obtained until production well is shut in due to low gas flow rate or maximum water production rate have been termed as ultimate oil and gas recoveries in this study.

Figure 4.1 explains the change in oil and gas recovery as the size of aquifer increased. The recovery of the gas under depletion condition was around 70% which increased gradually to 86% as the size of aquifer increased to 40 times that of reservoir size. This is because more and more water entered into the reservoir to fill the space created from the gas production and this influx of water resulted in maintaining reservoir pressure at higher level and less liquid is dropped from gas, so deliverability of the well was maintained at high level and well produces for long time as shown in figure 4.2. From figure 4.2, it can be notice that producing time for the well increased from 3100 days to almost 4000 days as size of aquifer increased to 40 times that of original size.

The influx of water from aquifer improved oil recovery, and oil recovery increased from 38% under depletion drive to around 56%. The reason behind this improved recovery is as reservoir pressure is maintained because of water influx, less and less oil from the gas condensed in the reservoir. This not only improved the oil production rate and recovery but also improved gas deliverability as relative permeability of gas is higher at low oil saturation.

As M (size of aquifer to reservoir volume) is further increased from 40 to 86, the recovery of gas decreased from 86% to 77%. The more water broke into the well early in the life and by pass the gas. Therefore, volumetric displacement efficiency decreased and more gas got trap into the reservoir. Reservoir pressure is maintained at higher level-reservoir abandonment pressure (reservoir pressure at shut in), has increased significantly from 1500 psia to 2400 psia as M increased from 40 to 86, as given in figure 4.3. So the size of aquifer is now getting detrimental to the reservoir performance. From figure 4.2, it can also be seen that shut in time for the well has decreased drastically from 3800 days to 3450 days as M increased from 40 to 86. One important thing can also be noticed that recovery of oil has not increased much as M increased from 40 although the reservoir pressure is maintained at high level. Water cut (as shown in figure 4.4) in all the above cases never increased above 25% as surface limit on water production was present. One water important thing is that water cut for higher aquifer is low (less than 20%), the reason for such low water cut is that oil production rate did not decrease as reservoir pressure was maintained at higher level and top of the layers were producing oil at high rates even though the bottom layers were watered out. When all the layers were watered out then well was shut in at higher oil rates as shown in figure 4.5.

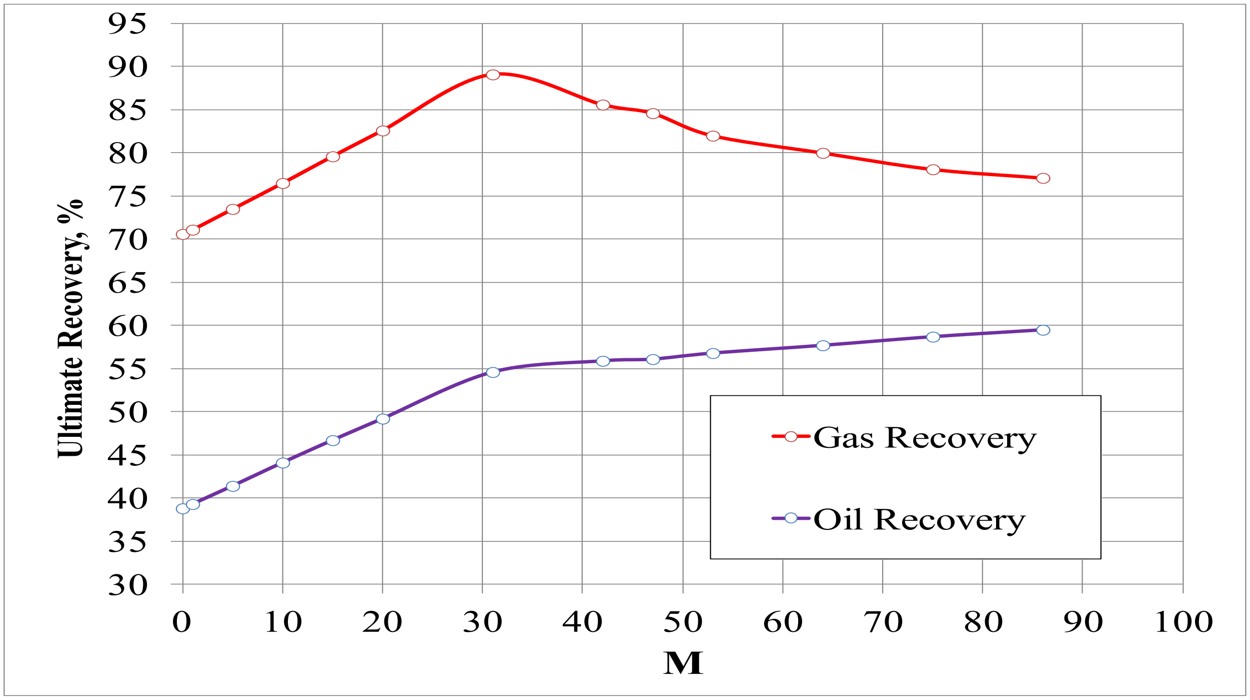


*Figure 4.1: Ultimate oil and gas recovery for different aquifer size.*


*Figure 4.2: Field production time for different aquifer size.*

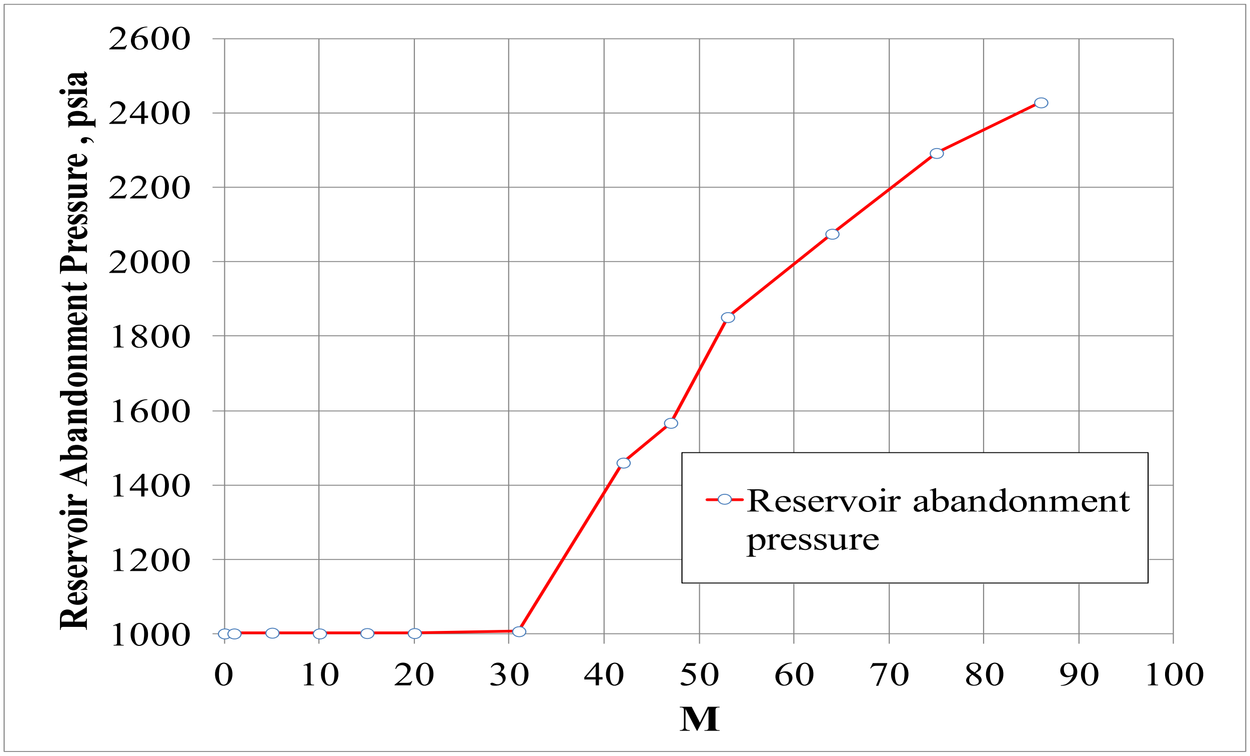


*Figure 4.3: Field abandonment pressure for different aquifer size.*

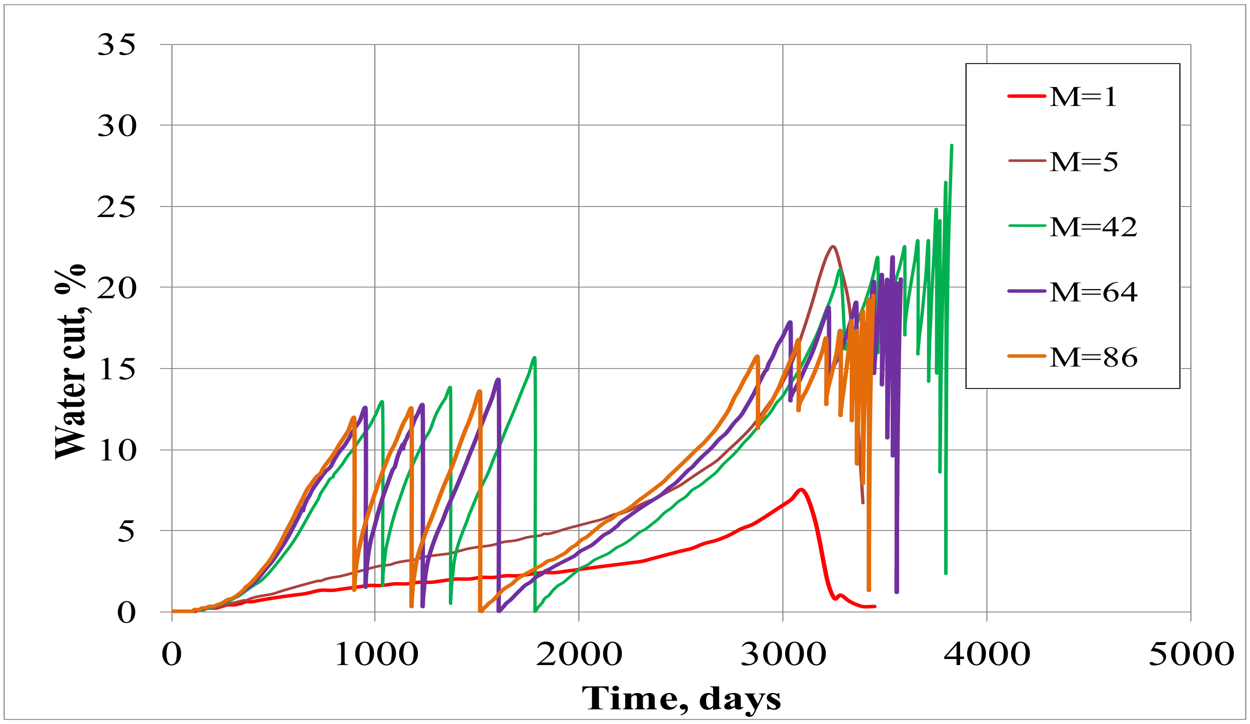


*Figure 4.4: Water cut for different aquifer size.*

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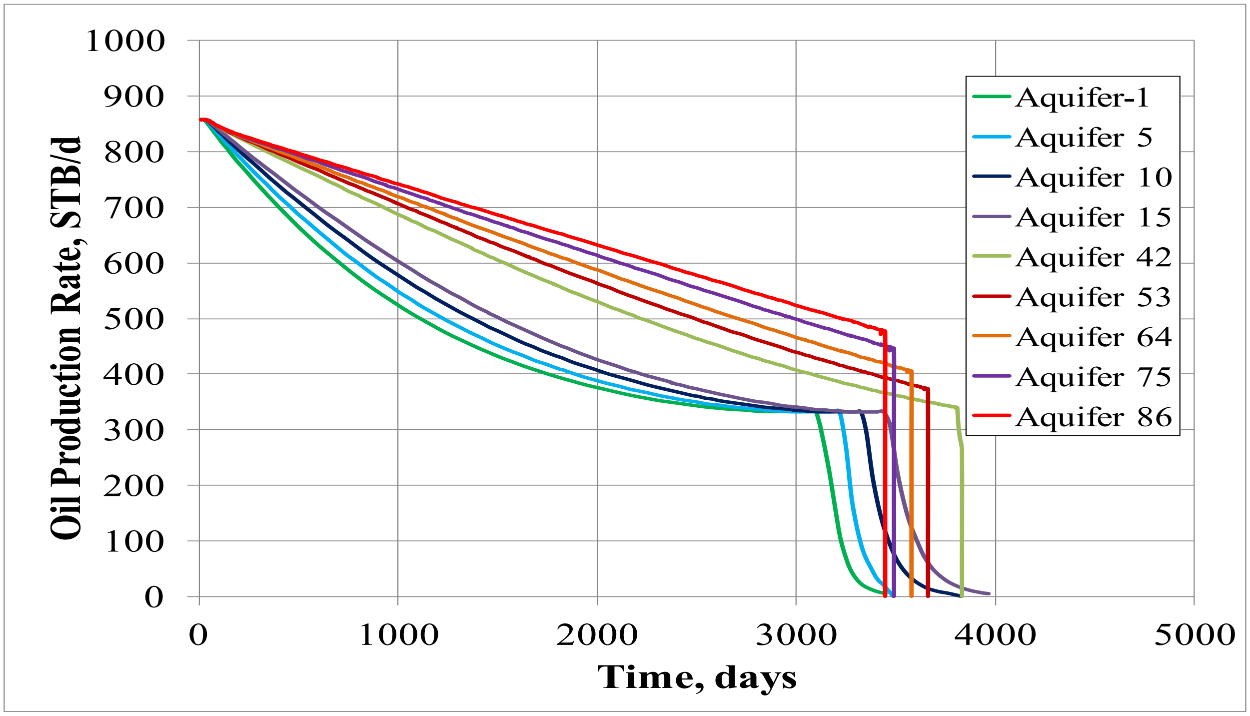


*Figure 4.5: Oil production rates for different aquifer size.*

### 4.1.2 Without Surface Limits

This is hypothetical case assuming that there is no limit on surface water production-all water produced from the reservoir can be handled. The results are summarized in figures 4.6 and 4.7 and have also discussed below:

The recovery of gas and oil continuously increased from 70% to 95% and 38% to 66% respectively as the M increased from 0 to 86. There is no such decline in recovery as was seen when M was around 40 with surface control case but rather recovery of gas is almost constant when M increased from 40 and recovery is rather the function of reservoir pressure-the longer well produce the higher the gas recovery and no gas is left in the reservoir because of water influx. There is no early shut in time for higher aquifer size as no surface limit is applied and well continuously produced both gas and water at high pressure, note that only minimum BHP and gas minimum rate control is applied in this case.

In this case, the well even produced water higher than 2000 STB/d when M was greater than 40 and more than 6000 STB/d when M was greater than 64 and water cut was very high and reached to almost 99% later in the life of the well. Because of higher production of water from the reservoir the reservoir abandonment pressure did not increase abruptly and remained at lower level as compared with the case with surface control-that is why the recovery of gas is higher in this case.

Therefore, reduction in the reservoir abandonment pressure by producing large volume of water from the reservoir can increase the ultimate recovery of gas. Therefore, water production limit greatly affects the recovery. The recoveries will be different if well can produce 1000 STB of water per day than 10 STB of water/d which emphasizes the important of well lift. In all further cases, the water production limit of 100 STB /d is applied in the simulation model.

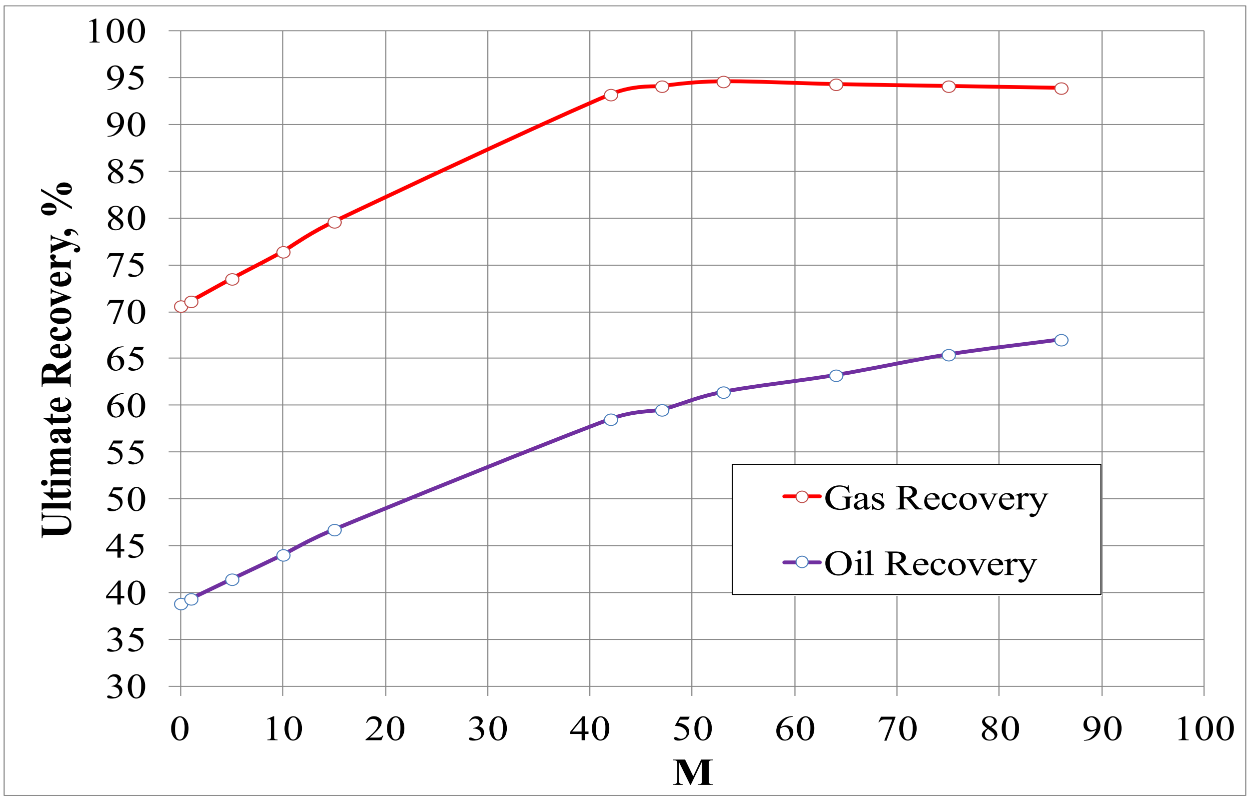


*Figure 4.6: Ultimate oil and gas recovery-without surface limits.*

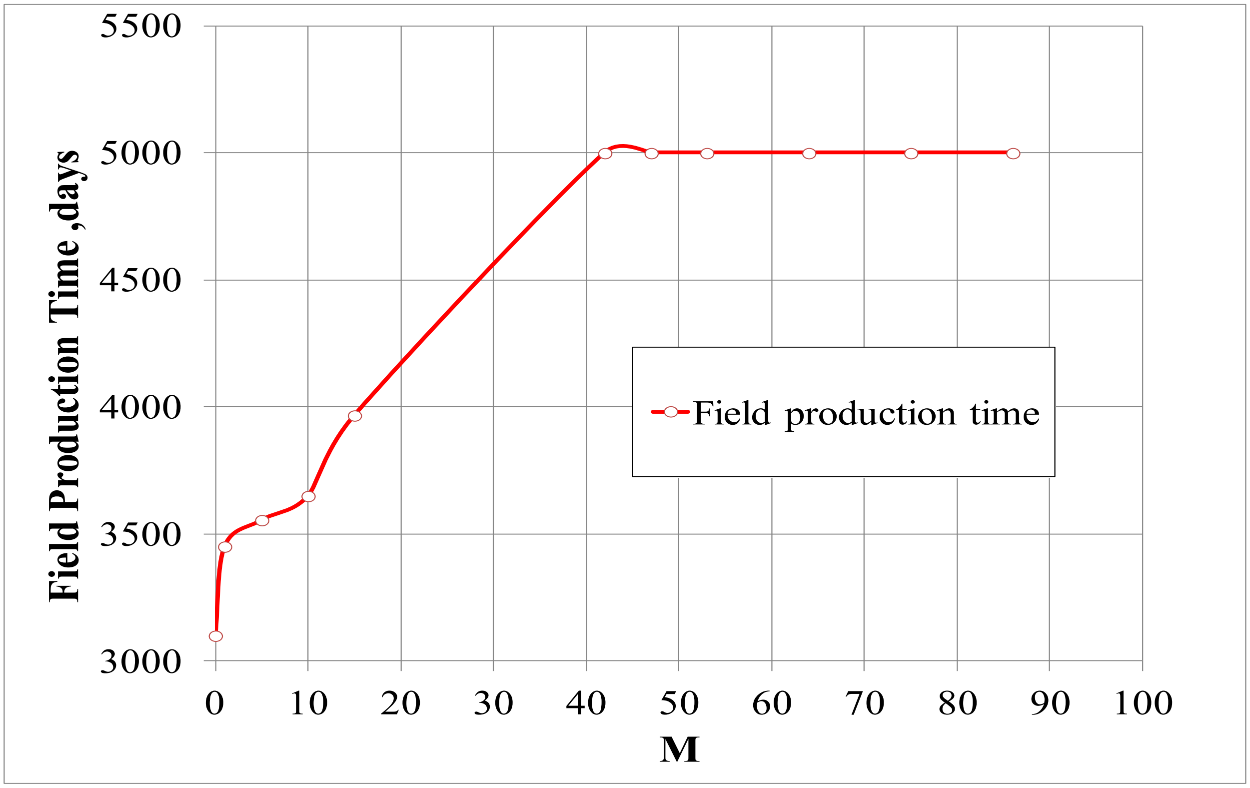


*Figure 4.7: Field production time-without surface limits.*

## 4.2 Effect of Aquifer Vertical Permeability

In this case, the vertical permeability of aquifer is changed and different cases are run for 1 mD, 10 mD, 100 mD and 1000 mD. The cases are run with surface limits and the figures 4.8 to 4.12 compare the ultimate recovery of oil and gas, field production time, water break through time and reservoir abandonment pressure.

From the figures, it is quite clear that as vertical permeability of aquifer decreased at a given aquifer size, the oil recovery decreased and gas recovery increased. The reason is same-as vertical permeability decreased, less and less water came to fill the space generated because of gas production so reservoir pressure is maintained at lower pressure causing more oil to condense in the reservoir and less oil is produced to surface. As discussed before, the gas recovery depends on abandoned reservoir pressure, the higher the reservoir pressure at a given time, the lower will be gas recovery. As from figure 4.12, it can be notice that reservoir abandonment pressure is lower for lower permeability aquifer resulted in high recovery of gas but low recovery of oil.

Form figures, one important point can also be noticed that the ultimate recoveries of oil and gas are independent of aquifer vertical permeability for limited aquifer size-M less than 15. The reason for such behavior is that as size of aquifer is limited, the influx of water from aquifer is not able to compensate the gas production. Reservoir pressure is always decreasing even when the vertical permeability of aquifer is 1000 mD. Even though, there is an early breakthrough of water in the lower layers of pay zone as aquifer permeability increased but the upper layer of the pay zone produced till the final limit of minimum BHP arrived. So, water from the limited aquifer size did not rise to top layers and because of this shut in time for limited aquifer size is almost constant.

Figure 4.11 explains the breakthrough time for different aquifer permeability as size of aquifer increased. The water broke into the well around 20 days when aquifer permeability is 1000 mD as compared to around 900 days when aquifer permeability is 1 mD. The work-over operations to shut the water producing lower layers will have to be started soon for high vertical permeable aquifer than low vertical permeable aquifer. The best economical method to produce high vertical permeable reservoir is to perforate far above the aquifer zone to delay water production. One more important point can also be noticed that water breakthrough time is almost constant for higher vertical permeable reservoir as M increased and the difference between 1 mD to 10 mD is much higher than the difference between 10 mD and 1000 mD.

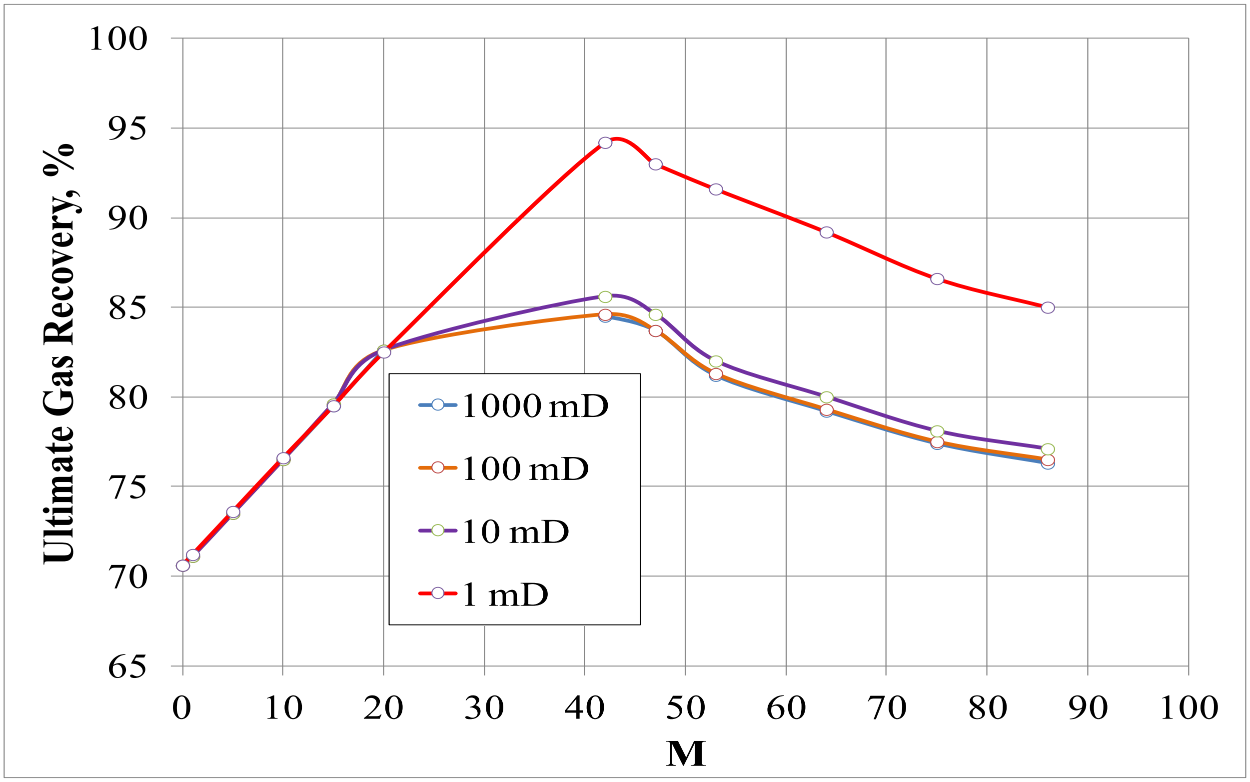


*Figure 4.8: Ultimate gas recovery for different aquifer size for different aquifer vertical permeability.*

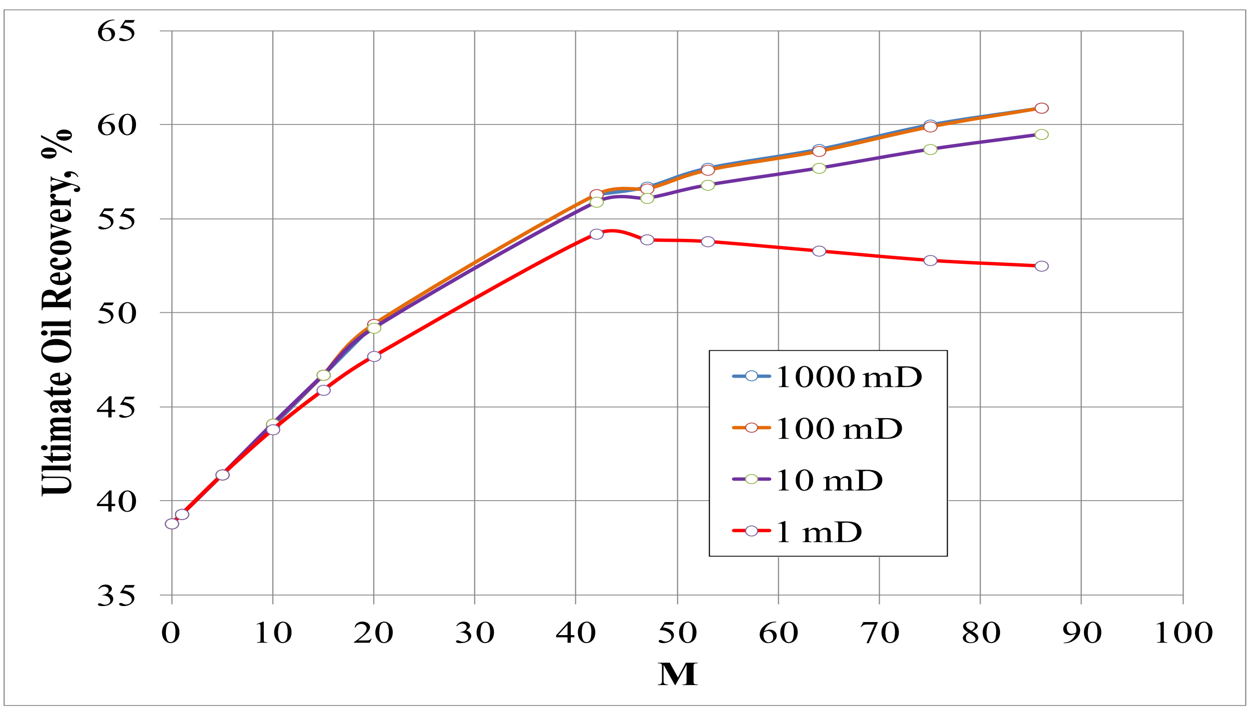


*Figure 4.9: Ultimate oil recovery for different aquifer size for different aquifer vertical permeability.*

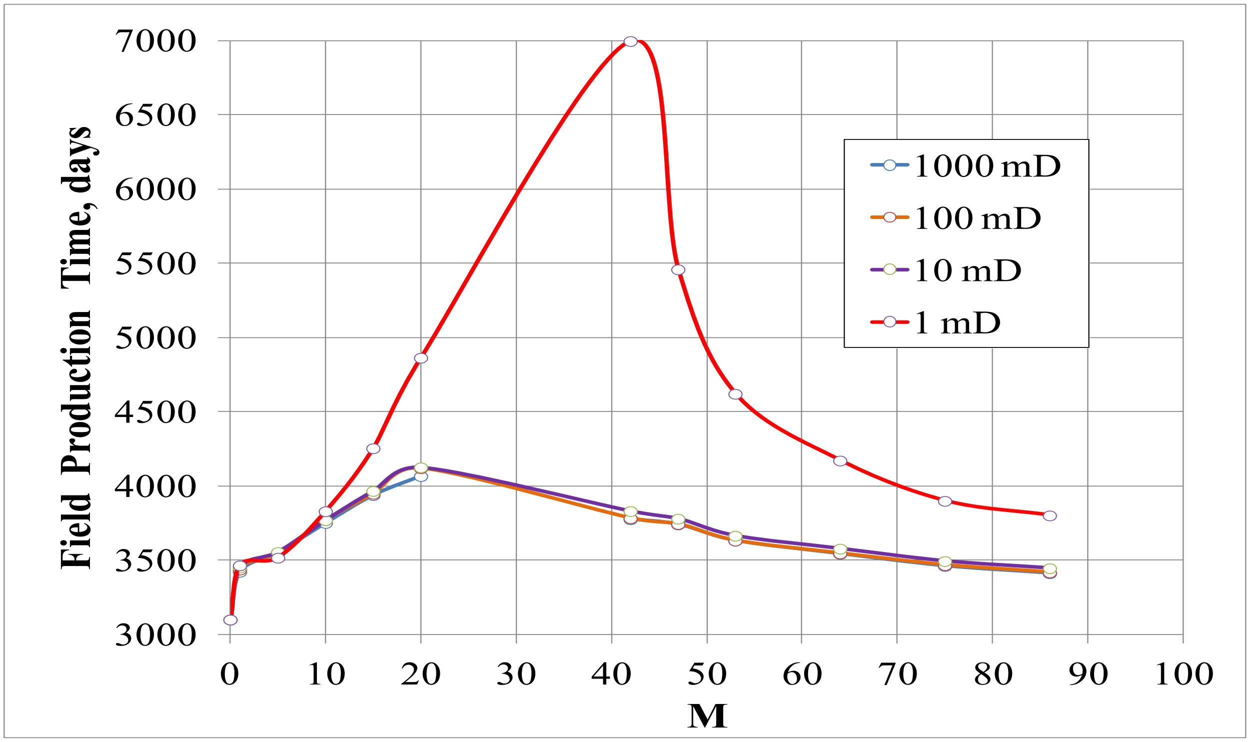


*Figure 4.10: Field production time for different aquifer size for different aquifer vertical permeability.*

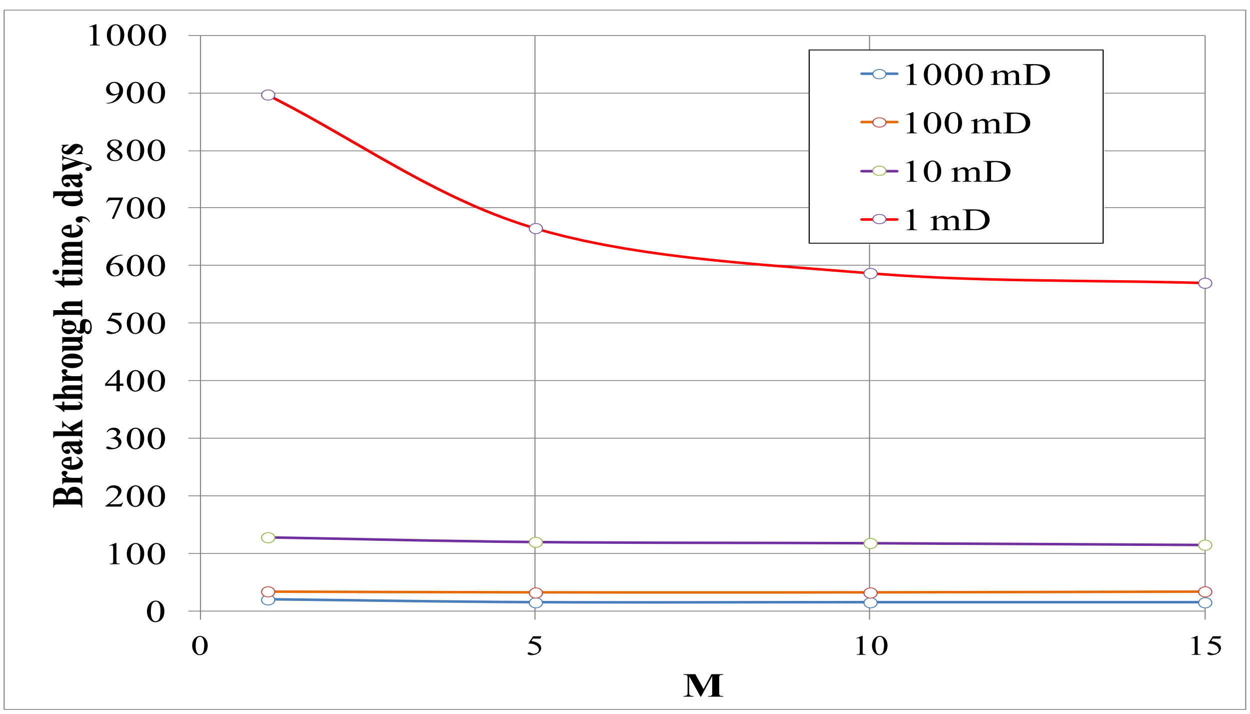


*Figure 4.11: Breakthrough time for different aquifer size for different aquifer vertical permeability.*

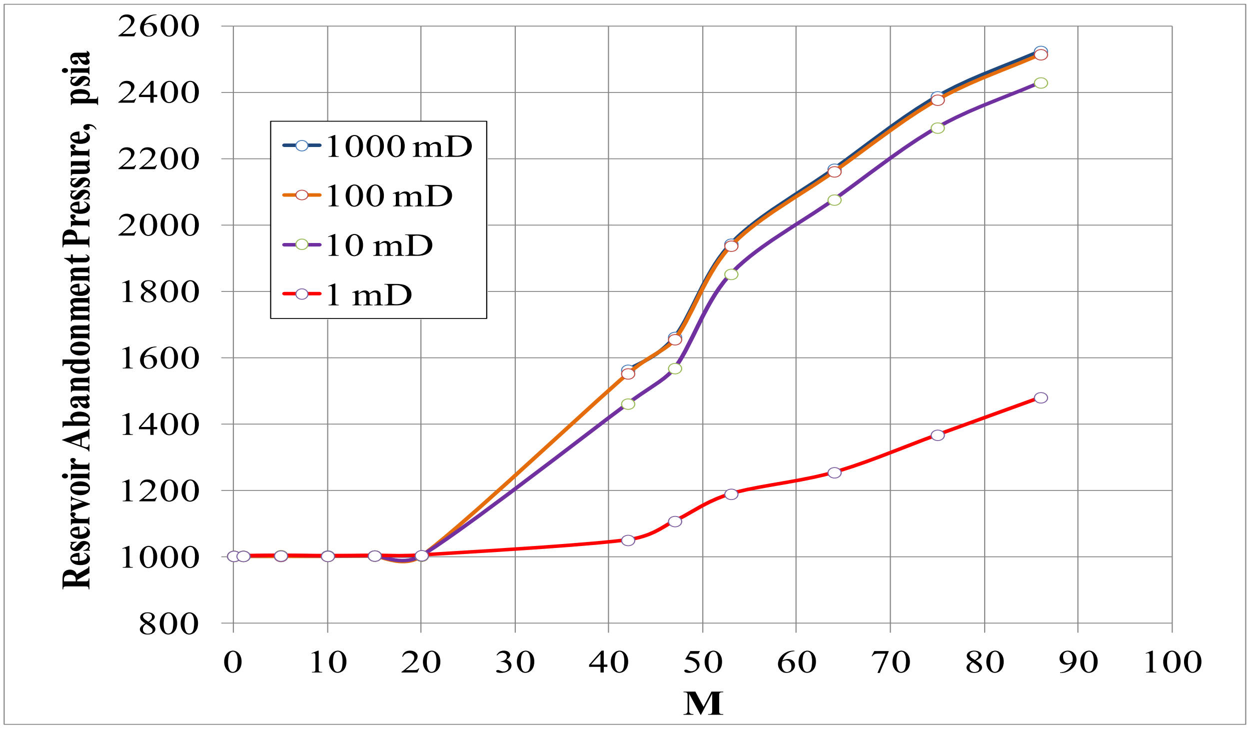


*Figure 4.12: Reservoir abandonment pressure for different aquifer size for different aquifer vertical permeability.*

## 4.3 Effect of Initial Reservoir Pressure

In this case, the effect of water influx is seen on gas condensate reservoir performance having different initial reservoir pressure. The reservoir pressure is increased from 3550 psia to 4000 psia, 4500 psia, and 5000 psia. The dew point pressure of the reservoir fluid is same in all cases. Therefore by increasing reservoir pressure, the under-saturation of the reservoir fluid has been increased.

From figure 4.13, it can be seen that ultimate gas recovery has three relationships with initial reservoir pressure

1) For low aquifer size-M less than 15, ultimate gas recovery increased as reservoir pressure is increased.
2) Medium aquifer size-M less than 60, ultimate gas recovery decreased as reservoir pressure is increased
3) Large aquifer size-M greater than 70, ultimate gas recovery is more or less independent of reservoir pressure.

Unlike gas recovery, oil recovery has only one relation-oil recovery increased as initial reservoir pressure increased for all aquifer size, figure 4.14.

For M=42, the ultimate gas recovery for 5000 psia reservoir pressure is lower than 3550 psia, the reason behind this low recovery is that field abandonment pressure is much higher, around 3000 days than 1500 days, causing large gas to get trap in the reservoir.

One more important thing can also be noticed that for reservoir with higher initial reservoir pressure, ultimate gas and oil recoveries are independent of the aquifer size-ultimate gas and oil recoveries are almost constant as aquifer size is increased. The possible reason for constant recovery at higher initial reservoir pressure is that the loss in recovery of gas due to depletion mechanism is balanced by additional gas recovery due to displacement recovery because of water influx. At lower reservoir pressures, the displacement recoveries are not so high resulting in larger trapping of gas as aquifer size increased. Although the reservoir abandonment pressure, figure 4.15, increased as aquifer size increased, the oil recovery is constant because the total gas recovery due to displacement process is same. Moreover, field total producing time, figure 4.16, is also constant for higher initial reservoir pressure even the aquifer size is increasing.

Therefore, at higher initial reservoir pressure, gas behaved like liquid so viscosity of gas increased and recoveries because of displacement of water increased but as reservoir pressure increased, the strength of aquifer also increased causing water to raise faster towards the production wells. Therefore, the end result is almost same trapping of gas regardless of the size of aquifer. Moreover, large under-saturation of reservoir fluid at higher initial reservoir pressure cause less liquid to dropped in the reservoir and resulted in high ultimate recovery of oil then cases with low initial reservoir pressure.

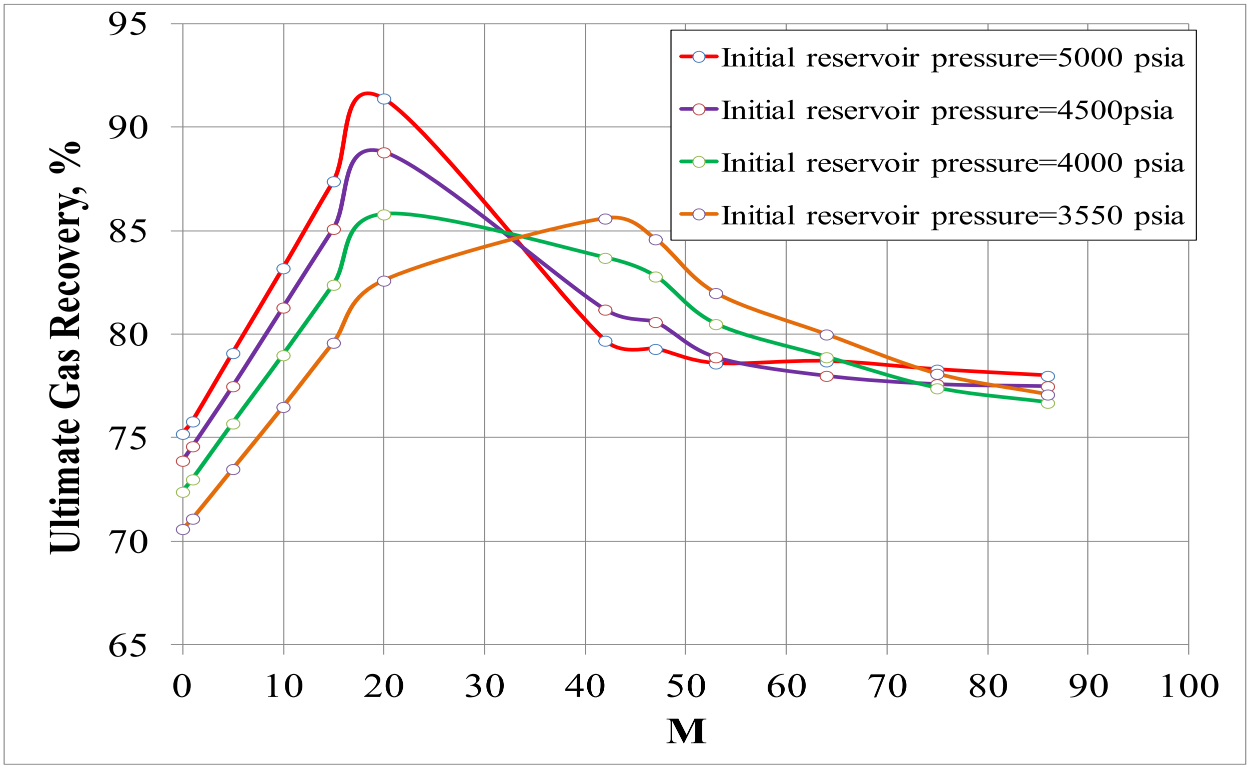


*Figure 4.13: Ultimate gas recovery for different aquifer size for different initial reservoir pressure.*

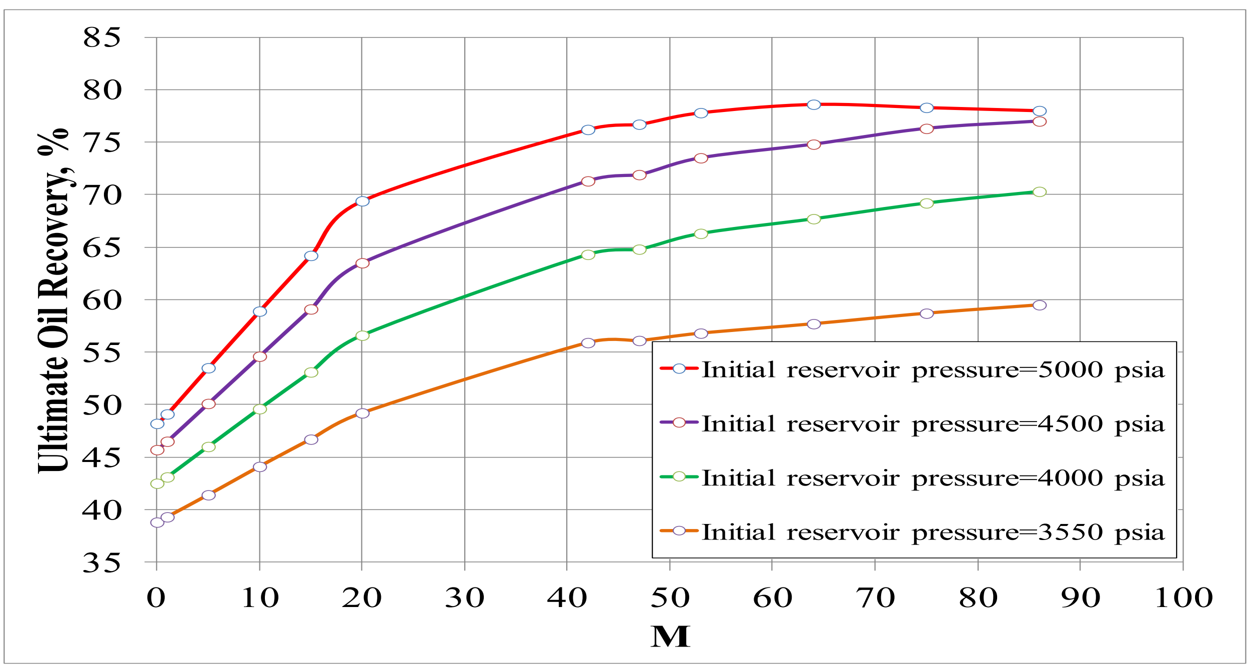


*Figure 4.14: Ultimate oil recovery for different aquifer size for different initial reservoir pressure.*

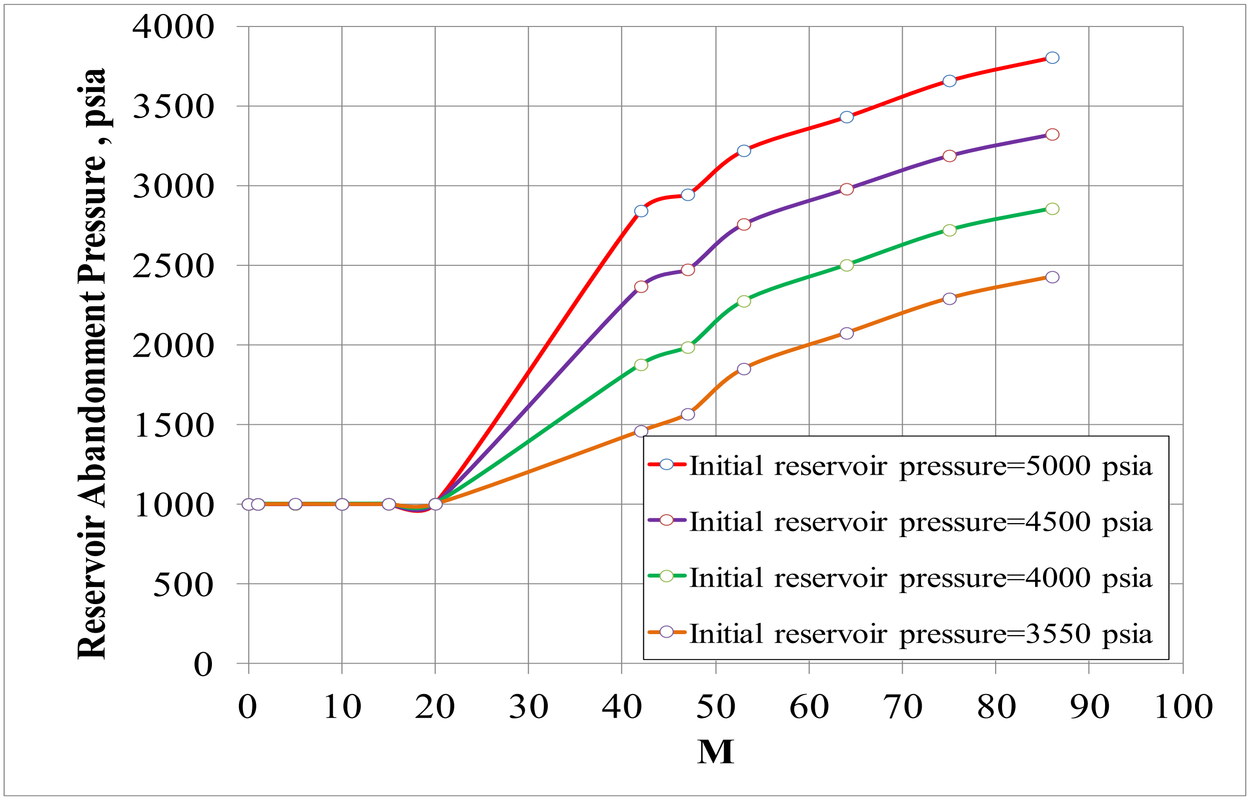


*Figure 4.15: Reservoir abandonment pressure for different aquifer size for different initial reservoir pressure.*

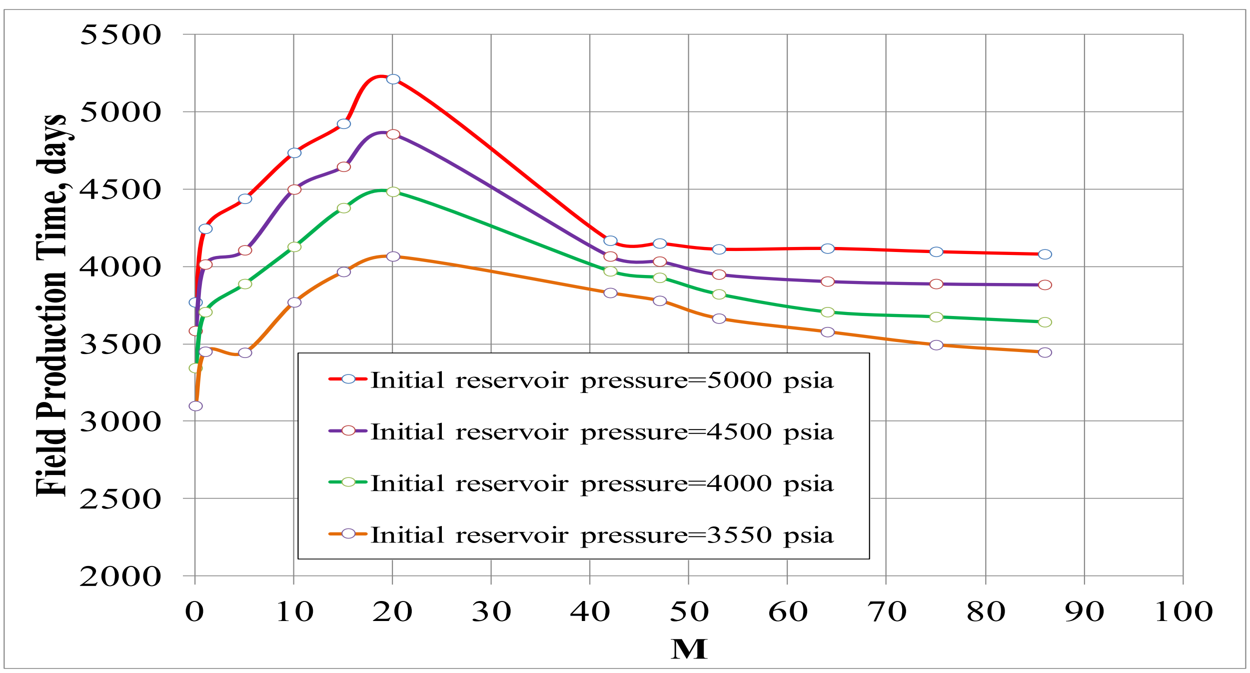


*Figure 4.16: Field production time for different aquifer size for different reservoir pressure.*

# 5 Reservoir Management Techniques on Water Drive Gas Condensate Reservoir

In this chapter, the reservoir management techniques have been applied to increase the ultimate recoveries from a particular water drive gas condensate reservoir. Cases are run to the original vertical heterogeneous reservoir with aquifer permeability equal to 10 mD. Four aquifer sizes are chosen for the study:

a) Aquifer size 5 times larger than pay zone (M=5)
b) Aquifer size 15 times larger than pay zone (M=15)
c) Aquifer size 42 times larger than pay zone (M=42)
d) Aquifer size 75 times larger than pay zone (M=75)

There are different techniques that can be applied to increase the ultimate gas recovery from water drive gas condensate reservoir like : production of gas at higher rates, continued production of well at very high water cut and drilling a well in aquifer to produce the water directly from aquifer zone. The reason behind producing water is that producing large volumes of water from well/aquifer reduces the effect of the aquifer and results in lower reservoir pressure and thus reduces the amount of trapped gas at field abandonment conditions and results is higher ultimate gas recovery. Any action taken which increases the ultimate gas recovery of a reservoir will also increase the net present value of that reservoir as well. But at lower reservoir pressure, because of higher production of gas and/or higher production of water, the more liquid will get condense from the gas in the reservoir and ultimate oil recovery may decrease. So economics of extra amount of gas produced must be compared with the decrease in ultimate oil recovery to evaluate the feasibility of that particular process.

## 5.1 Effect of Variation of Gas Production Rate

In this case, well with different gas production rate is produced. Figures 5.1, 5.2, 5.3 and 5.4 show the ultimate recovery of gas, oil and abandonment pressure for M=5, 15, 42 and 75 respectively.

From figures, it is clear that for limited aquifer size (M=5 and 15), increase in gas rate did not had any impact on ultimate oil and gas recovery and reservoir abandonment pressure. For M=5, the ultimate gas recovery was around 73% even the gas rate increased from 3 MMscf/d to 20 MMscf/d. Similarly the ultimate oil recovery was around 41% for all gas rates. The reason for such behavior is that the influx of water from aquifer was not capable to balance the gas production. Reservoir pressure was always decreasing even when the gas rate is low. Even though, there was an early breakthrough of water in the lower layers of pay zone at higher gas rate, the upper layer of the pay zone produced till the final limit of minimum BHP. Because of this constant abandonment pressure for limited aquifer size ultimate recoveries are same for all gas rates.

At higher aquifer size (M=42 and 75), both ultimate recoveries of oil and gas decreased as gas production rate increased. This is because at high gas rate, reservoir pressure decreased rapidly causing water from aquifer to move very quickly and resulted in early breakthrough of water and higher trapping of gas. So depletion mechanism is dominant over displacement mechanism at higher gas rate in gas condensate reservoir. For M=75, ultimate recovery of gas was around 83% and 70% when gas rate was 3 MMscf/d and 20 MMscf/d respectively. Moreover, ultimate oil recovery had decreased from 62% to 51% as gas rate decreased from 3 MMscf/d to 20 MMscf/d. At lower rates, the field production time increased and field produces till 20 years at 3 MMscf/d than 6 year at 20 MMscf/d (figure 5.5). Net present value evaluation of both the production scheme should be done to check the feasibility of the scheme.

Moreover, for lower gas rate, the pressure drop in the reservoir is only confined to near wellbore area. The oil that comes out of gas below dew point pressure in near well bore region has large oil saturation and thus has high mobility to flow into the well. This resulted in higher oil recovery as compared to higher gas rate where much of the oil is immobile.

Therefore, well should be produce at lower rates in order to increase the ultimate oil and gas recovery from a gas-condensate reservoir having large aquifer size.

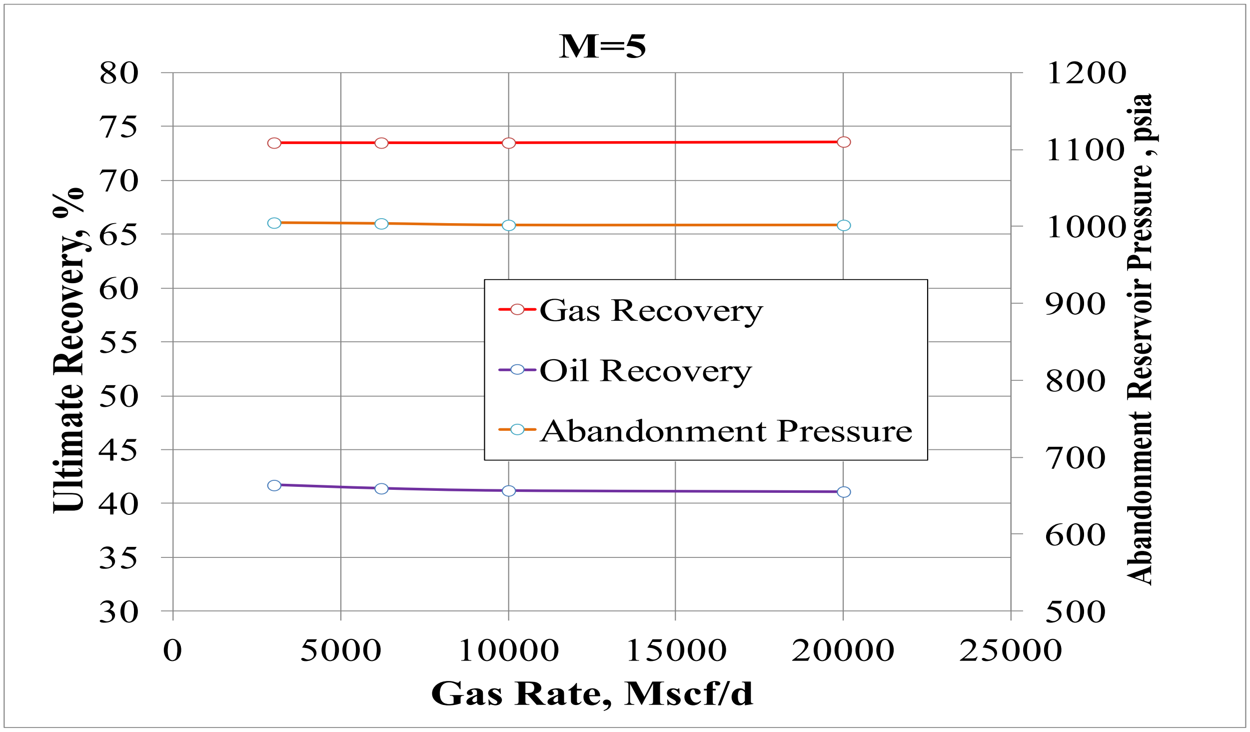


*Figure 5.1: Ultimate oil and gas recovery and reservoir abandonment pressure for different gas rates for M=5.*

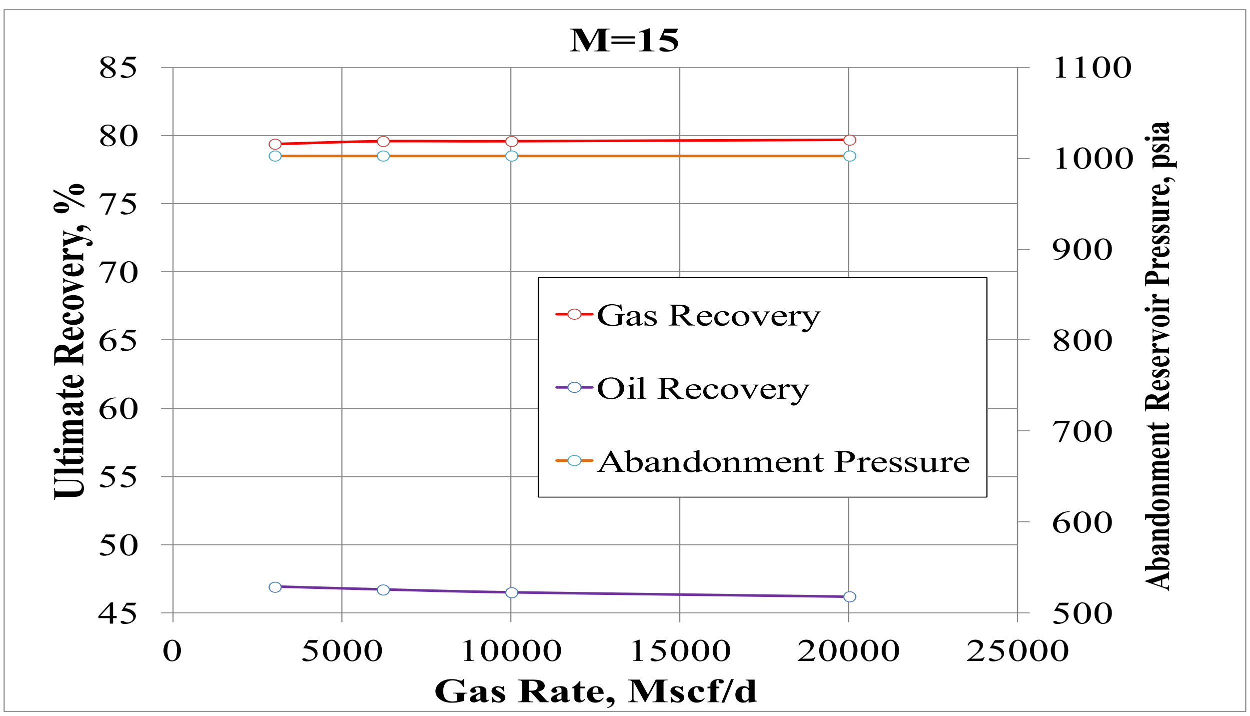


*Figure 5.2: Ultimate oil and gas recovery and reservoir abandonment pressure for different gas rates for M=15.*

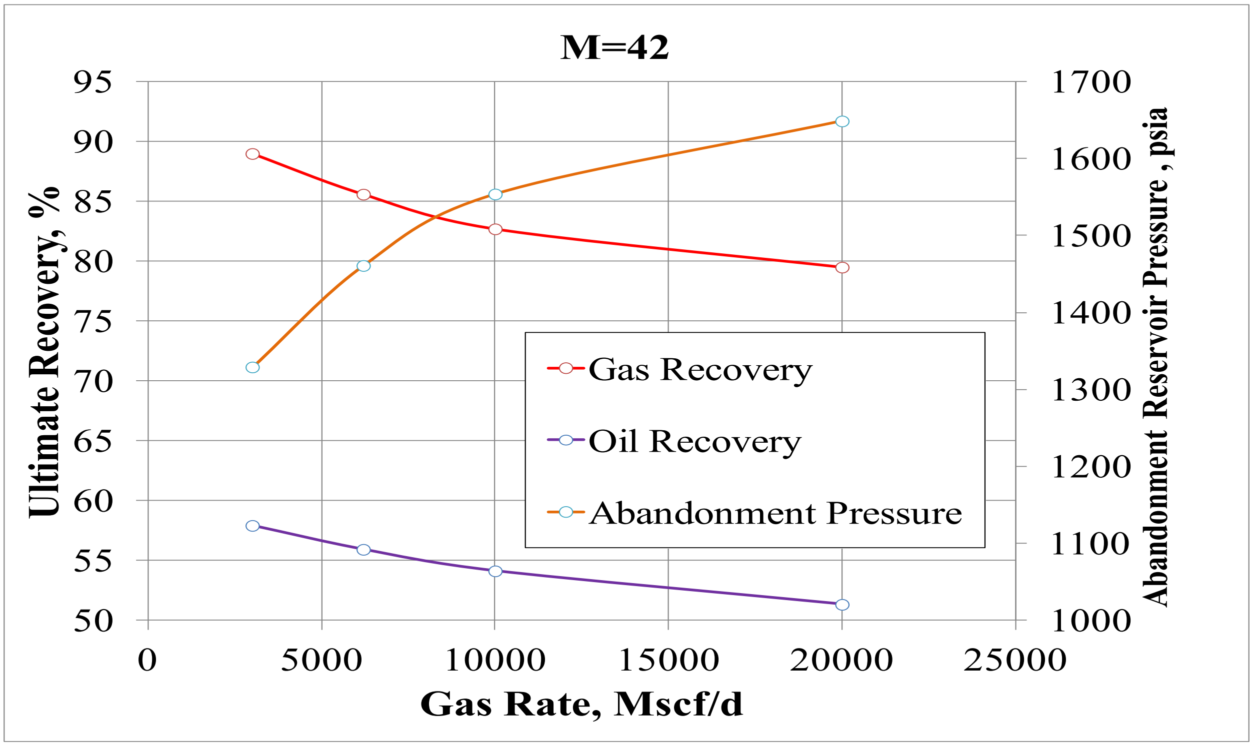


*Figure 5.3: Ultimate oil and gas recovery and reservoir abandonment pressure for different gas rates for M=42.*

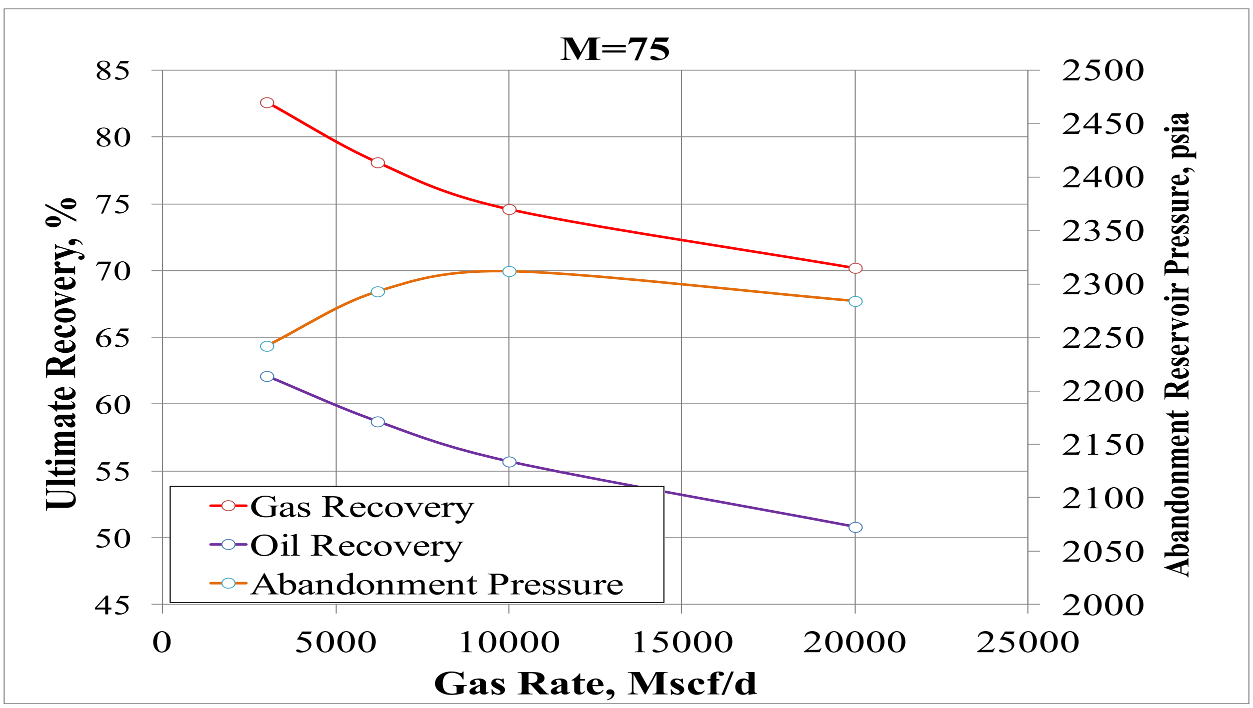


*Figure 5.4: Ultimate oil and gas recovery and reservoir abandonment pressure for different gas rates for M=75.*

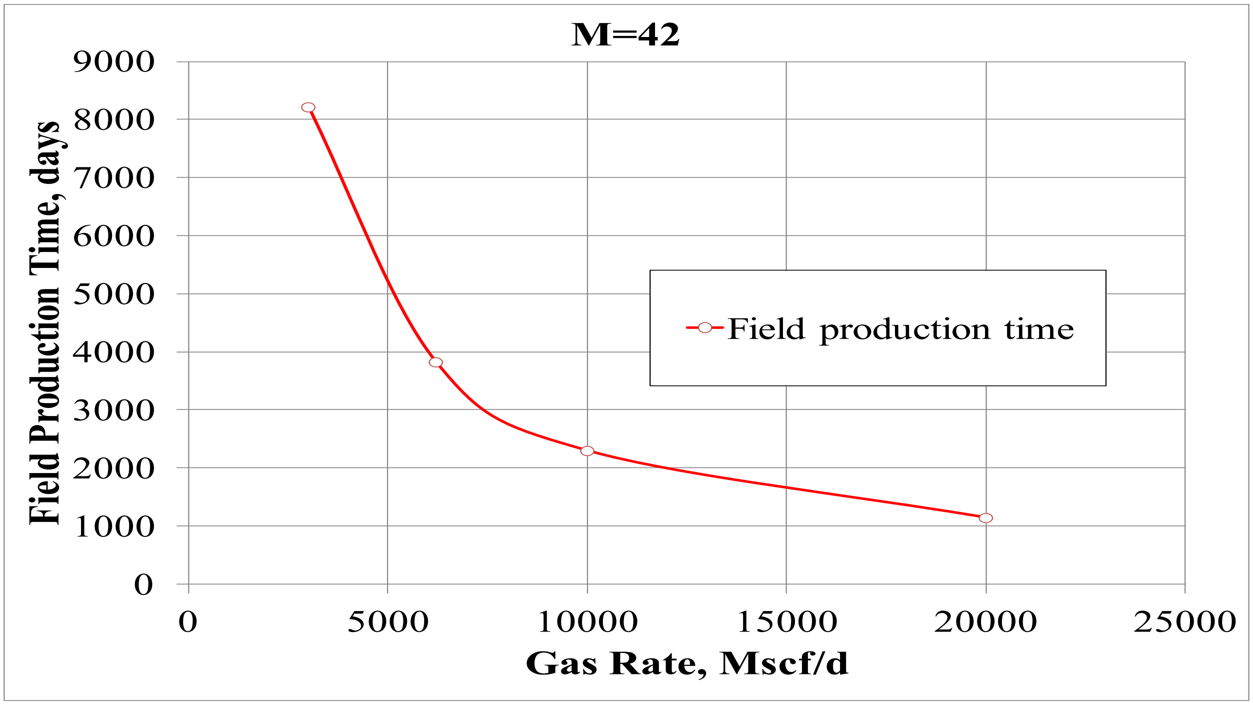


*Figure 5.5: Field production time for different gas rate for M=42.*

## 5.2 Gas Rate Combination

As noticed in previous section that although the recovery of both gas and oil increased at low gas rates, but field production time increased significantly. Therefore, because of this large production time, net present value of low gas production rate case may be low.

The highest recovery for a particular aquifer reservoir is when well is produced at low gas rate therefore recoveries as that of low gas rate case are desired and field production time as that of high gas production rate case is needed. So objective is to optimize the production rate to produce maximum from a given reservoir as early as possible.

In this case, the combinations of different rate are used to optimize the recovery. The well production rate is changed after producing the well for a particular time.

Following two larger aquifer sizes are chosen for the study:

a) Aquifer size 42 times larger than pay zone (M=42).

b) Aquifer size 75 times larger than pay zone (M=75).

The purpose of selecting larger aquifer size is that the effect of changing gas rate was quite large on ultimate recoveries for larger aquifer size reservoir.

Many cases were run with different gas rate combinations. In some cases, well is initially produced at lower rates and then after sometime well production rate is increased and in other cases, well is initially produced at higher rates and then rate is decreased. Moreover, time to change the gas rate was also changed. Table 5.1 summarizes the results of this case.

*Table 5.1: Ultimate oil and gas recovery for different gas rate combination for M=42.*

| Combination No. | Gas Rate Combination (Mscf/d) | Time of Changing first Gas Rate (years) | Gas Recovery (%) | Oil Recovery (%) | Reservoir Abandonment Pressure (psia) | Field Production Time (days) |
|---|---|---|---|---|---|---|
| 1 | 3000-6000 | 6 | 56.3 | 85.8 | 1458 | 5045 |
| 2 | 4000-6000 | 5 | 56.2 | 85.7 | 1457 | 4564 |
| 3 | 4000-7000 | 5 | 55.8 | 85 | 1482 | 4141 |
| 4 | 4000-7000 | 6 | 55.8 | 85 | 1480 | 4271 |
| 5 | 4000-8000 | 6 | 55.5 | 84.5 | 1497 | 4016 |
| 6 | 5000-7000 | 6 | 55.8 | 85.1 | 1476 | 3992 |
| 7 | 4000-6000 | 4 | 56.1 | 85.7 | 1459 | 4430 |
| 8 | 7000-4000 | 6 | 56.6 | 87.4 | 1404 | 4437 |
| 9 | 7000-4000 | 5 | 56.7 | 87.4 | 1404 | 4707 |
| 10 | 7000-5000 | 6 | 56.2 | 86.4 | 1437 | 3926 |
| 11 | 7000-5000 | 5 | 56.3 | 86.5 | 1433 | 4079 |
| 12 | 8000-3000 | 6 | 56.9 | 88.5 | 1366 | 4578 |
| 13 | 8000-3000 | 5 | 57.1 | 88.6 | 1360 | 5190 |
| 14 | 8000-4000 | 6 | 56.4 | 87.2 | 1413 | 3944 |
| 15 | 8000-4000 | 5 | 56.5 | 87.4 | 1407 | 4254 |

From the table, it is clear that larger recoveries are obtained when the gas rate is decreased after initially producing the well at high gas rate. For example, the both ultimate oil and gas recoveries for the gas rate combination 8000-3000 Mscf/d (Combination number 12 and 13 in table 5.1) are higher than all other combinations. Even the second highest recovery is when rate decreased from 7000 Mscf/d to 4000 Mscf/d (Combination number 8 and 9 in table 5.1).

Generally, gas condensate reservoirs are initially produced at low rates to delay the liquid drop out in the bulk of the reservoir and to concentrate the liquid saturation near the wellbore and then gas rate is increased afterwards. However, this strategy is not very profitable for strong water drive gas condensate reservoir. The reason behind low recovery for such case is when gas rate is increased after producing at low gas rate, the influx of water from aquifer also increased rapidly and breakthrough occurred early, resulted in large trapping of gas. On the other hand, when gas rate is decreased suddenly after producing at high rates, the influx of water decreased and delay in breakthrough occurred. It can be seen from table 5.1 that field producing time for 8000-3000 Mscf/d rate combination is much higher than 4000-8000 Mscf/d and 8000-4000 Mscf/d rate combinations. Moreover, the abandonment pressure for 8000-3000 Mscf/d rate combination is also low as compared to other combinations.

Same strategy was checked on the reservoir having M=75. Well produced at constant rate for five years and then rate was changed afterword. The results are summarized in the table 5.2.

*Table 5.2: Ultimate oil and gas recovery for different gas rate combination for M=75.*

| Combination No. | Gas Rate Combination (Mscf/d) | Oil Recovery (%) | Gas Recovery (%) | Abandonment Pressure (psia) | Field Production Time (days) |
|---|---|---|---|---|---|
| 1 | Constant 3000 | 62.1 | 82.6 | 2242 | 7637 |
| 2 | Constant 6000 | 58.7 | 78.1 | 2293 | 3494 |
| 3 | 8000-3000 | 60.8 | 82.1 | 2263 | 4589 |
| 4 | 8000-4000 | 59.9 | 80.6 | 2278 | 3788 |
| 5 | 7000-5000 | 58.4 | 77.4 | 2298 | 4093 |
| 6 | 7000-4000 | 60.3 | 80.8 | 2274 | 4248 |
| 7 | 5000-7000 | 58.3 | 77.4 | 2297 | 3577 |
| 8 | 4000-8000 | 57.7 | 76.4 | 2301 | 3548 |
| 9 | 4000-7000 | 58.4 | 77.4 | 2296 | 3837 |

From table 5.2, it is clear that combination of high and low gas rates has both advantages of achieving higher ultimate recoveries and lower field production time.

Therefore, reservoir having large aquifer size should produce with high and low gas rate combination to optimize the recovery.

## 5.3 Production of Water

One important thing can also noticed from the tables 5.1 and 5.2 that lower the reservoir abandonment pressure, higher is the ultimate gas recovery. In this case, reservoir abandonment pressure is decreased by producing water. Water production for aquifer reduces the effect of the aquifer and results in lower reservoir pressure. Lower reservoir pressure may reduce the amount of trapped gas at field abandonment conditions but may decrease oil recoveries as reservoir pressure will not be maintained.

Two larger aquifer sizes are chosen for the study:

a) Aquifer size 42 times larger than pay zone (M=42).

b) Aquifer size 75 times larger than pay zone (M=75).

Production well produced gas at constant gas rate of 6200 Mscf/d and an additional water production well is placed in the simulation model which is producing water from the aquifer. The opening of the water production well and rate is the variable use to optimize the ultimate oil and gas recoveries. Figures 5.6, 5.7 and 5.8 show the ultimate oil and gas recoveries obtained for water production rate of 1000 STB/d, 2000 STB/d, and 3000 STB/d.

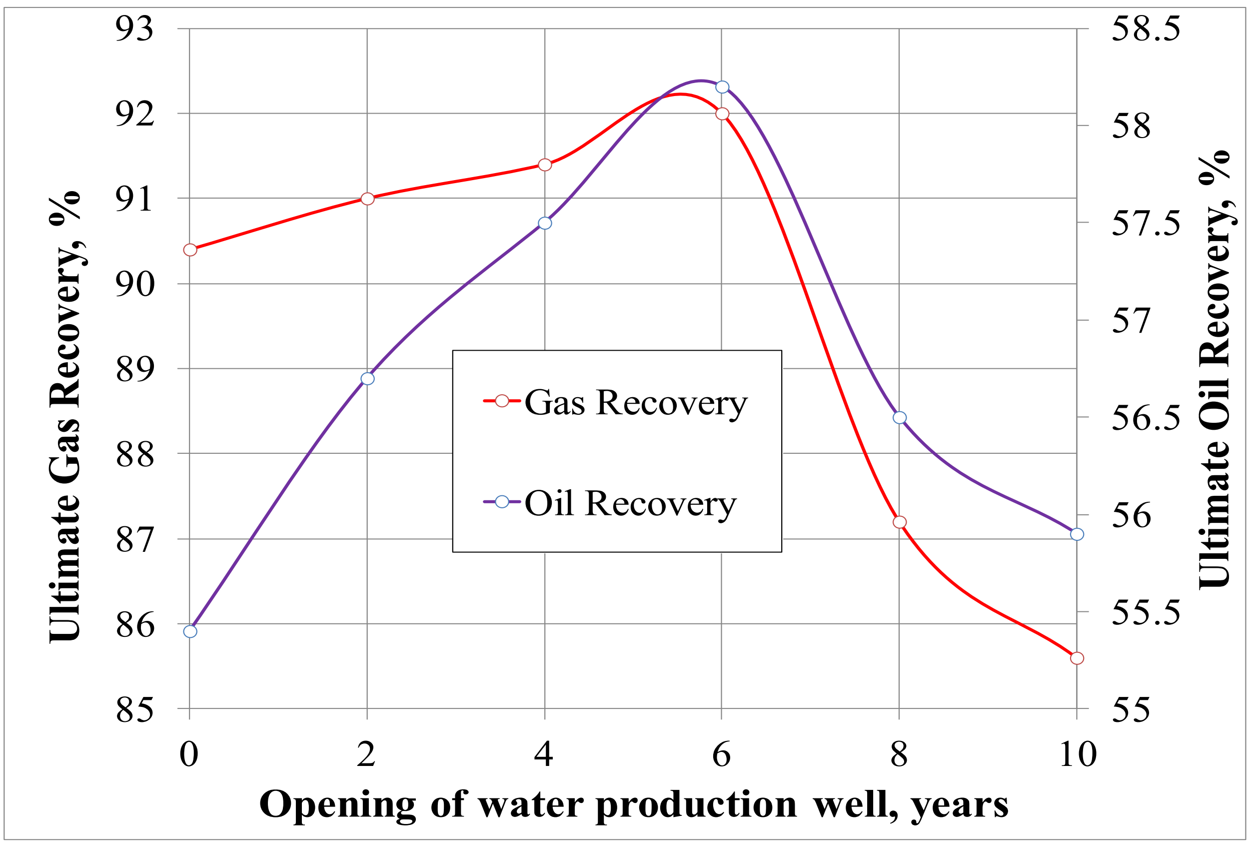


*Figure 5.6: Ultimate gas and oil recovery for water production rate=1000 STB/d.*

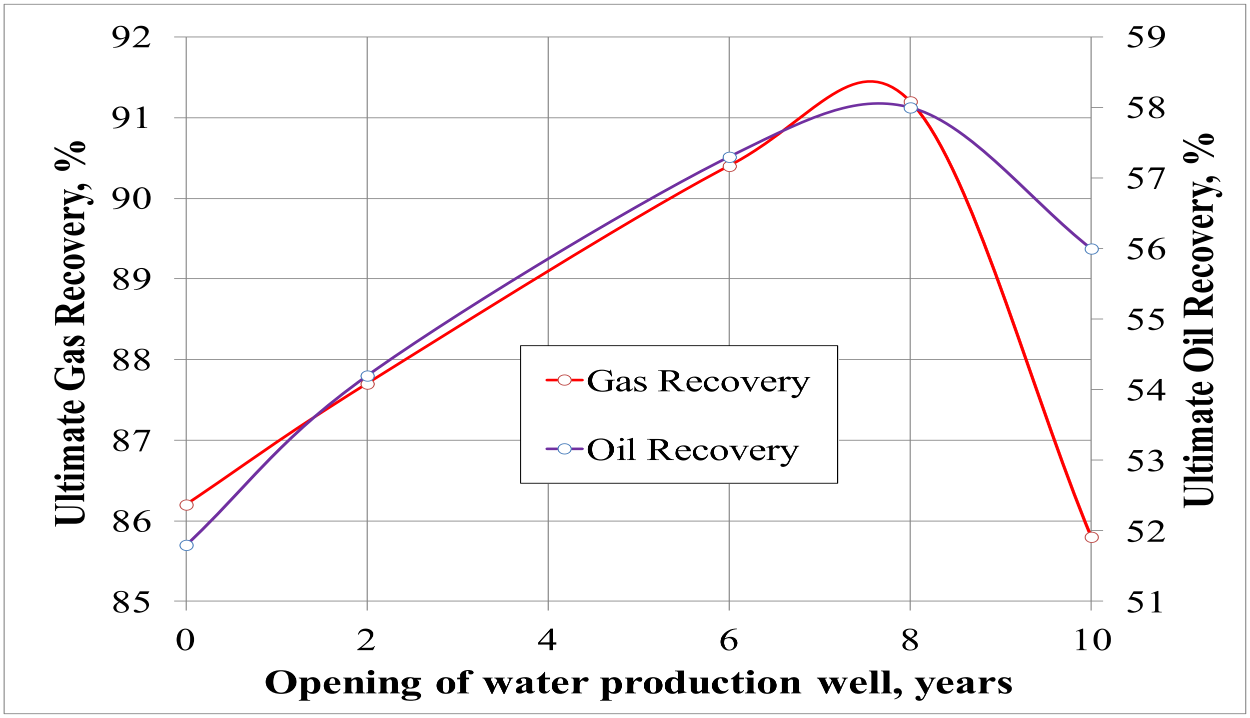


*Figure 5.7: Ultimate gas and oil recovery for water production rate=2000 STB/d.*

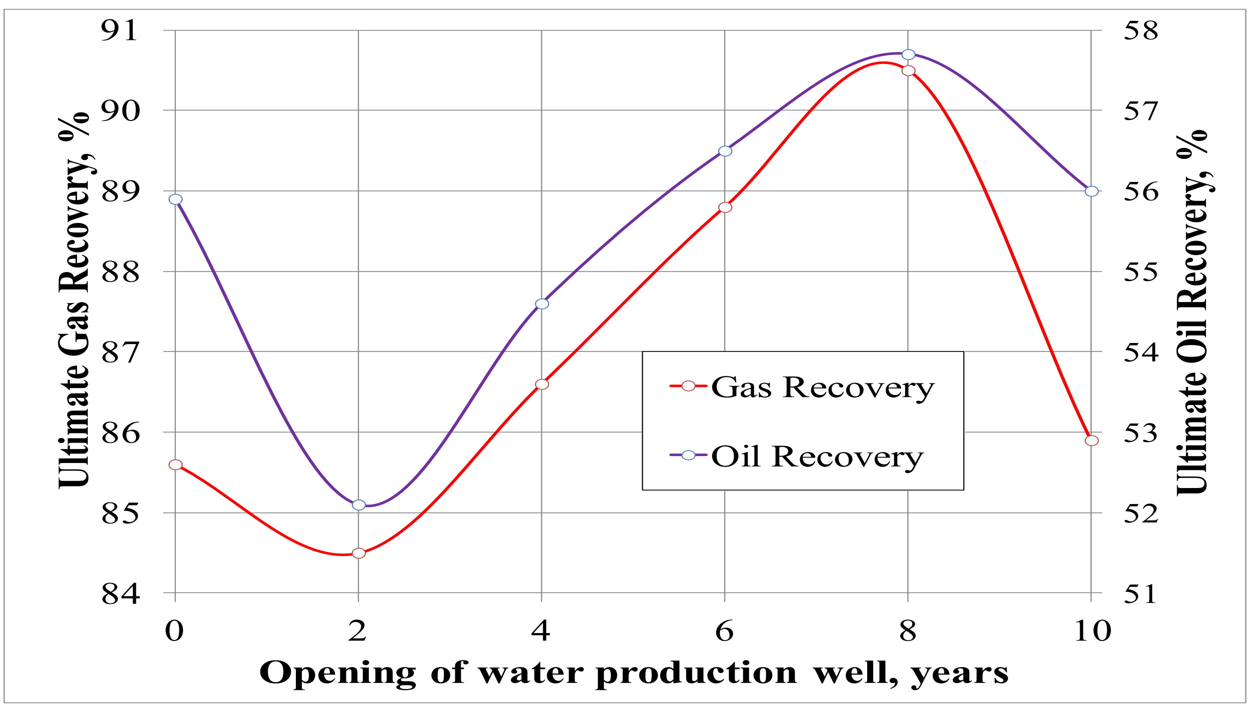


*Figure 5.8: Ultimate gas and oil recovery for water production rate=3000 STB/d.*

The highest gas and oil recovery were 92% and 58.2% respectively, when water production well with production rate of 1000 STB/d placed on production after 6 years of gas production. Moreover, these recoveries were even higher for the case when the well was producing at very low gas rate and the case when gas rate combination was used to enhance the field production time and field production time is much lower than the low gas rate case and approximately equal to rate combination case.

Therefore, the water production from a gas condensate reservoir can significantly improves the ultimate recoveries but water production rate and timing of producing water production well should be taken care for optimum designing. Moreover, economics of drilling of additional well with increment oil and gas recoveries should be evaluated.

# 6 Waterflooding in Gas Condensate Reservoir

## 6.1 Base Case

The effect of water injection is studied on limited aquifer size gas condensate reservoir. The size of aquifer is same as that of reservoir (i.e. M=1). The Cartesian model is used in this study and the base case has 9, 9 and 20 grids in x, y and z directions respectively. First 12 layers are hydrocarbon zone and remaining 8 layers are water aquifer zone. The well production rate is 6.2 MMscf/d, as given in third SPE comparative project. The model also has same vertical heterogeneity between the layers as given in the SPE paper. Other parameters are same as those used to study the effect of water influx. The Production well is located in cell (1, 1) and producing from the first top 8 layers. Initial fluids in places are given in table 6.1.

*Table 6.1: Initial fluid in place in base case.*

| | |
|---|---|
| Gas ( MMscf) | 27691 |
| Oil (MSTB) | 3831 |
| Hydrocarbon Pore Volume, HCPV (MRB) | 24396 |

The results from the base case-without water injection, are given in table 6.2.

*Table 6.2: Results from base case.*

| | |
|---|---|
| Ultimate Gas Recovery (%) | 71.1 |
| Ultimate Oil Recovery (%) | 38.8 |
| Field Abandonment Pressure (psia) | 1004 |
| Field Production Time (days) | 4015 |

The reservoir produces the maximum rate of oil for only small period of time and then goes on continuous decline, as given in figure 6.1, because reservoir pressure declined quickly below the dew point and liquid saturation around the wellbore increased very rapidly. After two years of production, the oil saturation near well bore in the high permeable layers was around 28%. This amount of liquid can significantly decrease the well deliverability, especially for low permeable reservoirs.

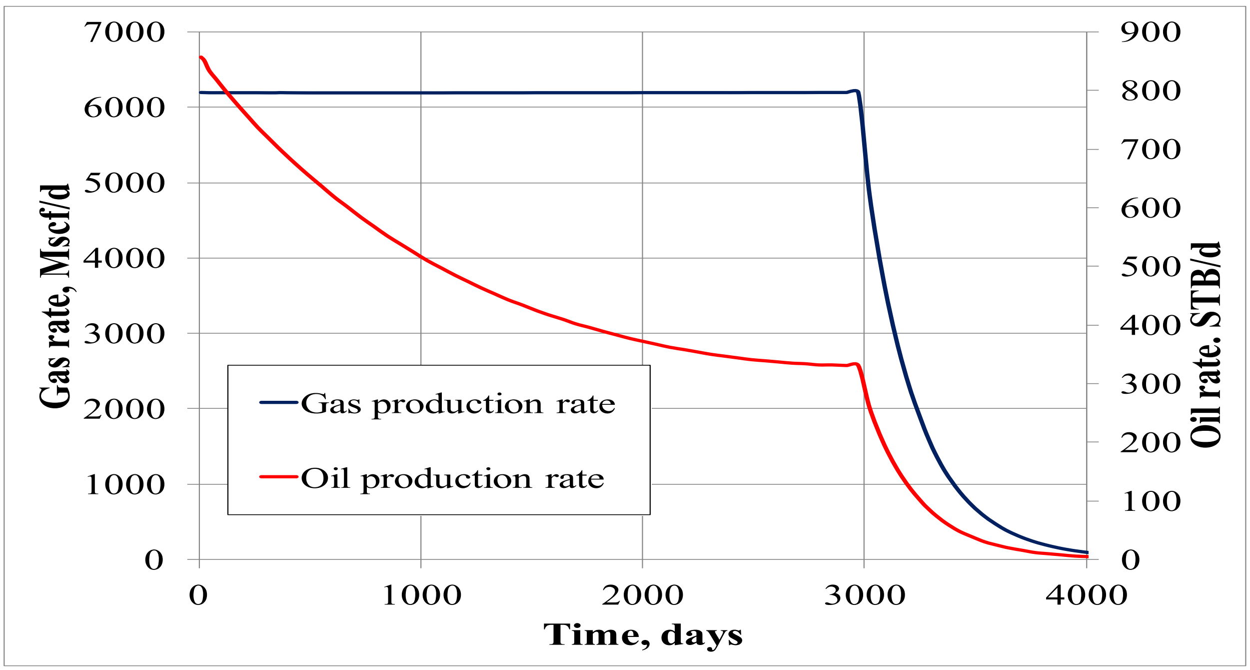


*Figure 6.1: Depletion case-oil and gas production rate.*

## 6.2 Effect of Injection Rate on Reservoir Performance

Figure 6.2 explains the change in oil and gas recovery as the injection rate increased. The water injection well has been placed in grid cell (9, 9) and perforated in the last four layers-in the aquifer zone. The injection well is injecting water from the first day and have been injected till production well reaches its economical limit. Economical limits and well bore constraints are defined in the table 6.3.

*Table 6.3: Constraints used in the simulation model.*

| | |
|---|---|
| Minimum bottom-hole pressure (psia) | 1000 |
| Maximum Water Production rate (STB/d) | 100 |
| Minimum Gas Production rate (Mscf/d) | 100 |

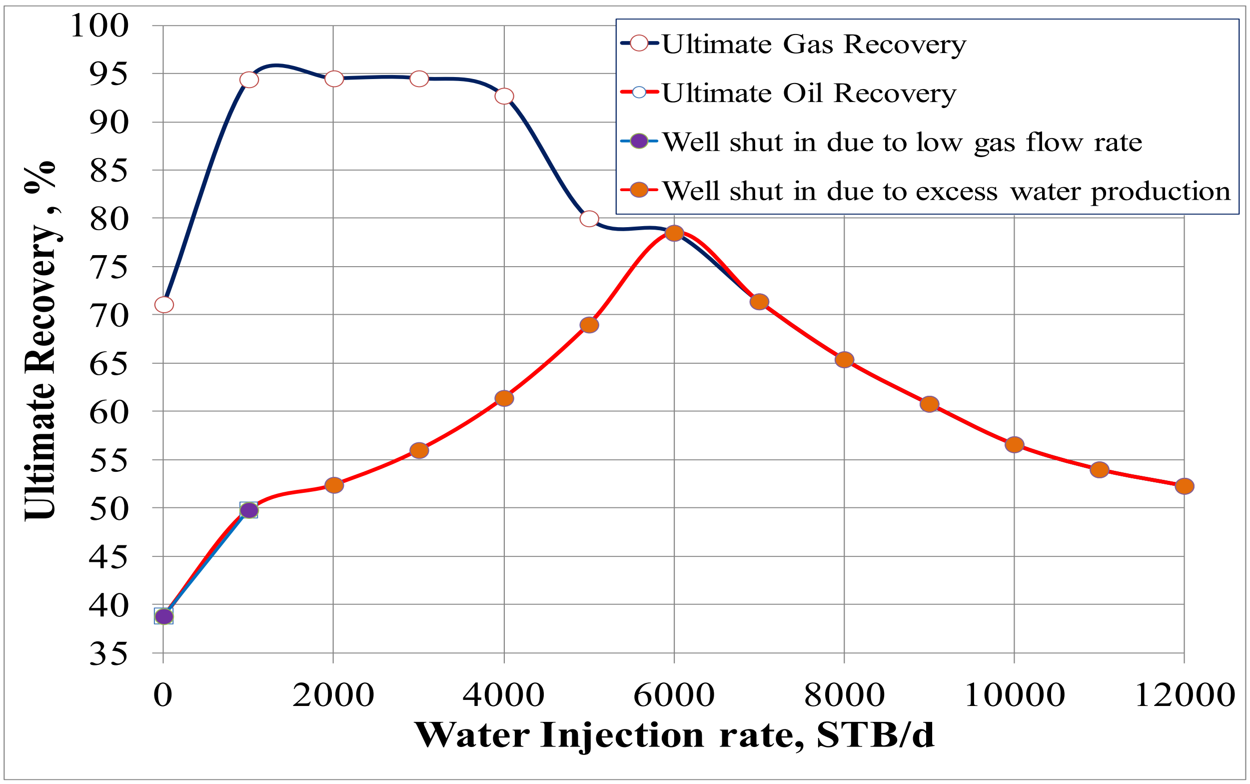


*Figure 6.2: Ultimate oil and gas recovery for different water injection rates.*

As expected, the oil recovery increased gradually to 78%-much higher than base case oil recovery, as the injection rate increased to 6000 STB/d. Even the effect of injecting small amount of water was quite high-the ultimate oil recovery increased from 38.8% to 50% and ultimate gas recovery from 71.1% to 95% at water injection rate of 1000 STB/d. The reason for such increase is that injected water balance the gas production and maintained reservoir pressure at higher level causing less or no liquid to drop from gas. Also, the deliverability of the well is maintained and well produced plateau gas rate for long time for lower injection rate (below 4000 STB/d), as shown in figure 6.3. Note from figure 6.3 that as water injection rate increased from

4000 STB/d the plateau period decreased and the well was shut in at initial gas production rate. Except for depletion and water injection of 1000 STB/d case, the well was shut in due to high water production rate-all layers were watered out before well reaches to its minimum gas rate limit. For low water injection rate ( injection rate below 4000 STB/d), well produced significant amount of gas and oil before shut in due to pressure maintenance and reservoir abandonment pressure (as shown in figure 6.5) had not increased significantly and field production time (as shown in figure 6.4) decreased significantly.

At higher injection rate (greater than 6000 STB/d), the oil recovery decreased as injection rate increased. The decrease in recovery is because of trapping of large amount of gas condensate in the reservoir which has also resulted in lower field production time (figure 6.4). The field had to shut in earlier because all producing layers were watered out-producing large amount of water, which has also resulted in higher abandoned pressure (figure 6.5).

One important point can also be observed from figure 6.2 that at the low injection of water (below 4000 STB/d), the ultimate gas recovery was constant as abandonment pressure was almost constant so trapping of gas did not occur at low injection rates. But, field production time significantly decreased as injection rate increased from 1000 STB/d to 4000 STB/d. So increasing injection rate was beneficial as injected water partially supported the pressure and resulted in improved recovery of oil and lower field production time. But, as injection rate increased from 4000 STB/d, the ultimate gas recovery decreased as more water broke into the production well and resulted in higher abandoned pressure. Interestingly, the oil recovery increased when injection rate increased till 6000 STB/d. At higher rates (greater than 6000 STB/d), ultimate gas recovery decreased-the same reason as explained earlier.

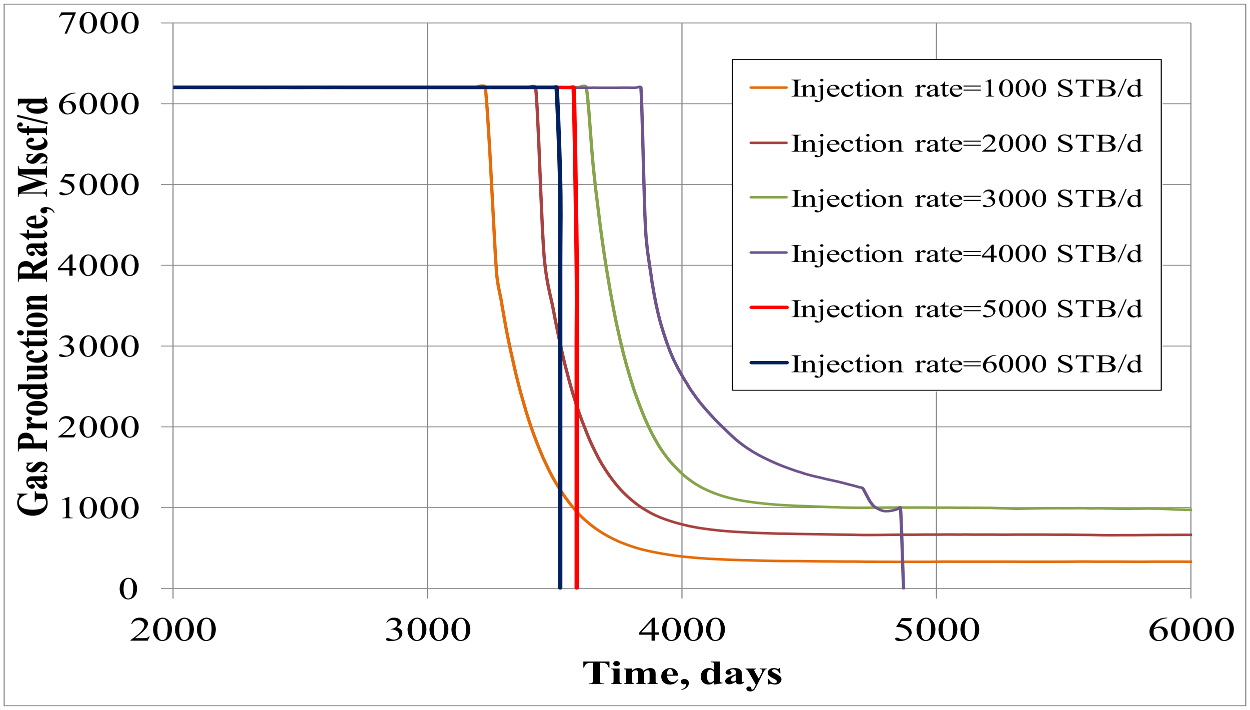


*Figure 6.3: Gas production rate for different water injection rates.*

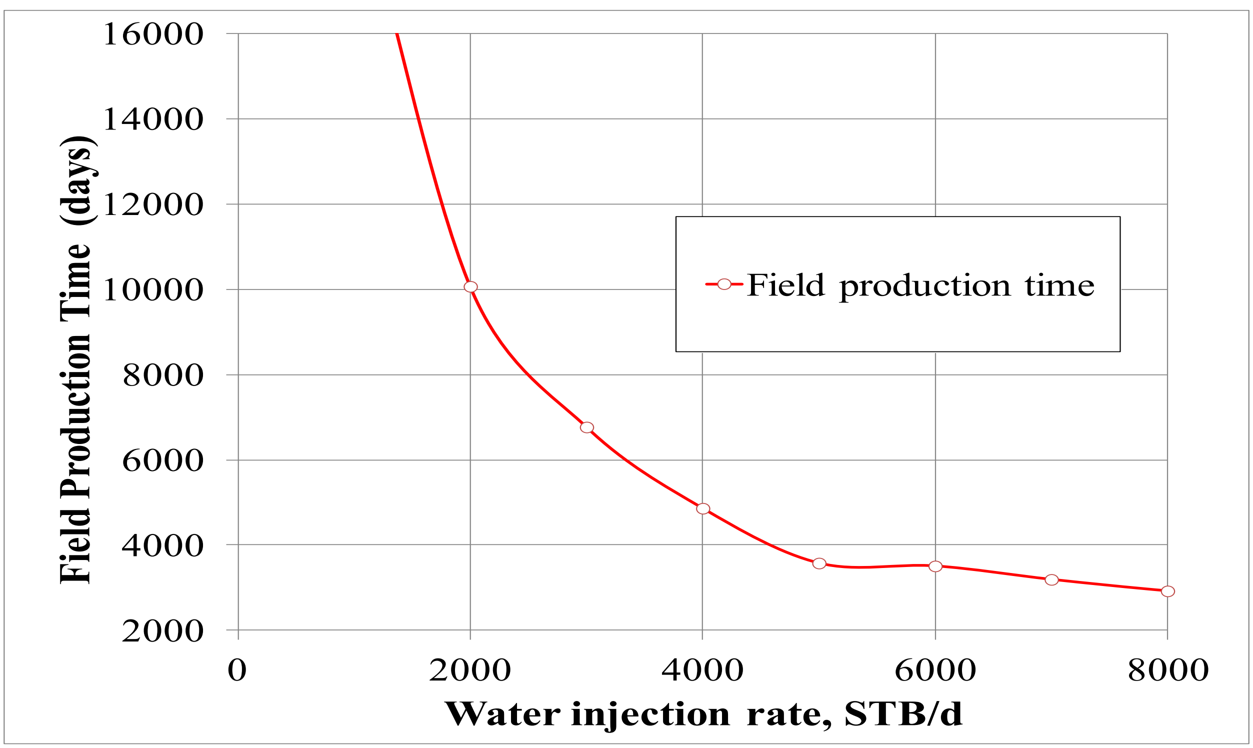


*Figure 6.4: Field production time for different water injection rates.*

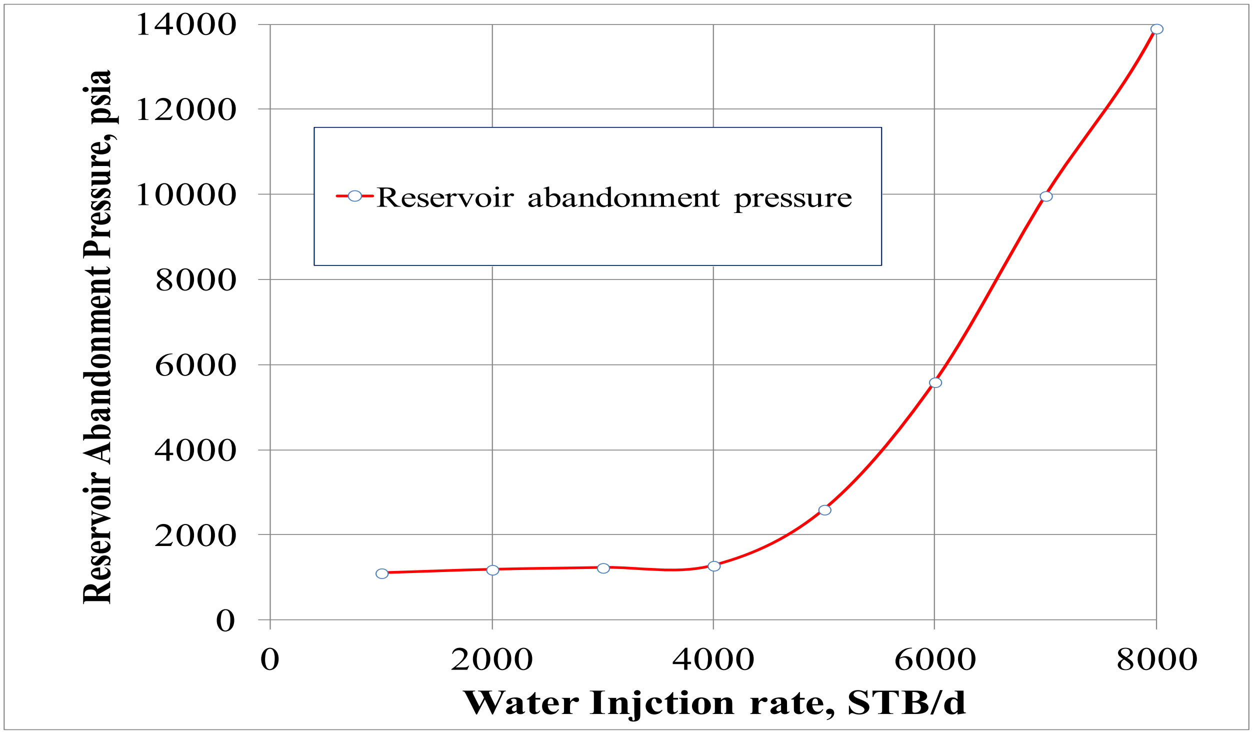


*Figure 6.5: Reservoir abandonment pressure for different water injection rates.*

From figure 6.6, it can also be seen that water cut of the well when 1000 STB/d of water was injected in the reservoir is almost zero indicating that reservoir behaved like depletion case. However, as water injection rate increased, water broke early into the production well and water cut increased steadily. One important thing can be notice for 2000 STB/d and 3000 STB/d case that production well produced long after the water breakthrough showing that although, bottom layers were watered-out, the upper layers were still producing gas. For higher water injection rate cases (water injection rate above 4000 STB/d), not only water broke early but well was also abandoned early as all layers were watered out quickly. One more important thing is that water cut for higher water injection rate is low (less than 20%), the reason for such low water cut is that oil production rate for high water injection rate did not decrease as reservoir pressure was maintained near to initial reservoir pressure and top of the layers produced oil at high rates even though the bottom layers were watered out. When all the layers were watered out then well was shut in at higher oil rates. Figure 6.7 gives the details of oil production rate variation for different water injection rate cases.

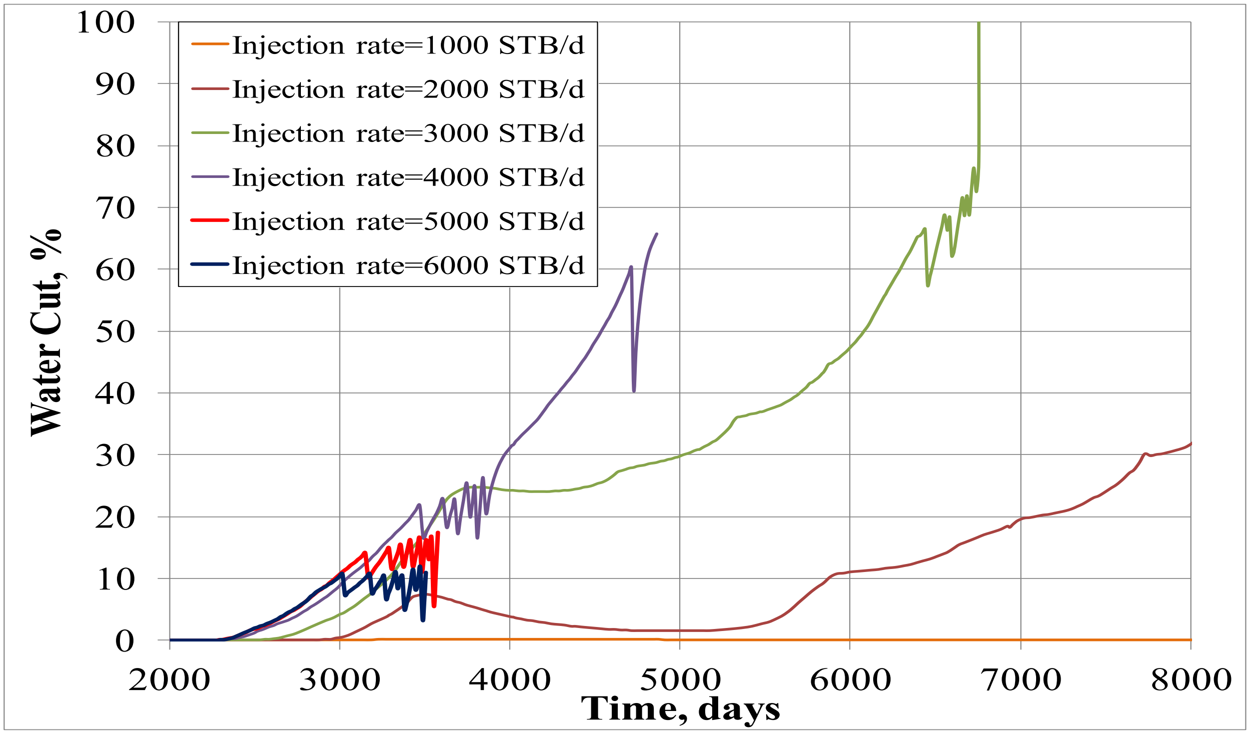


*Figure 6.6: Water cut for different water injection rates.*

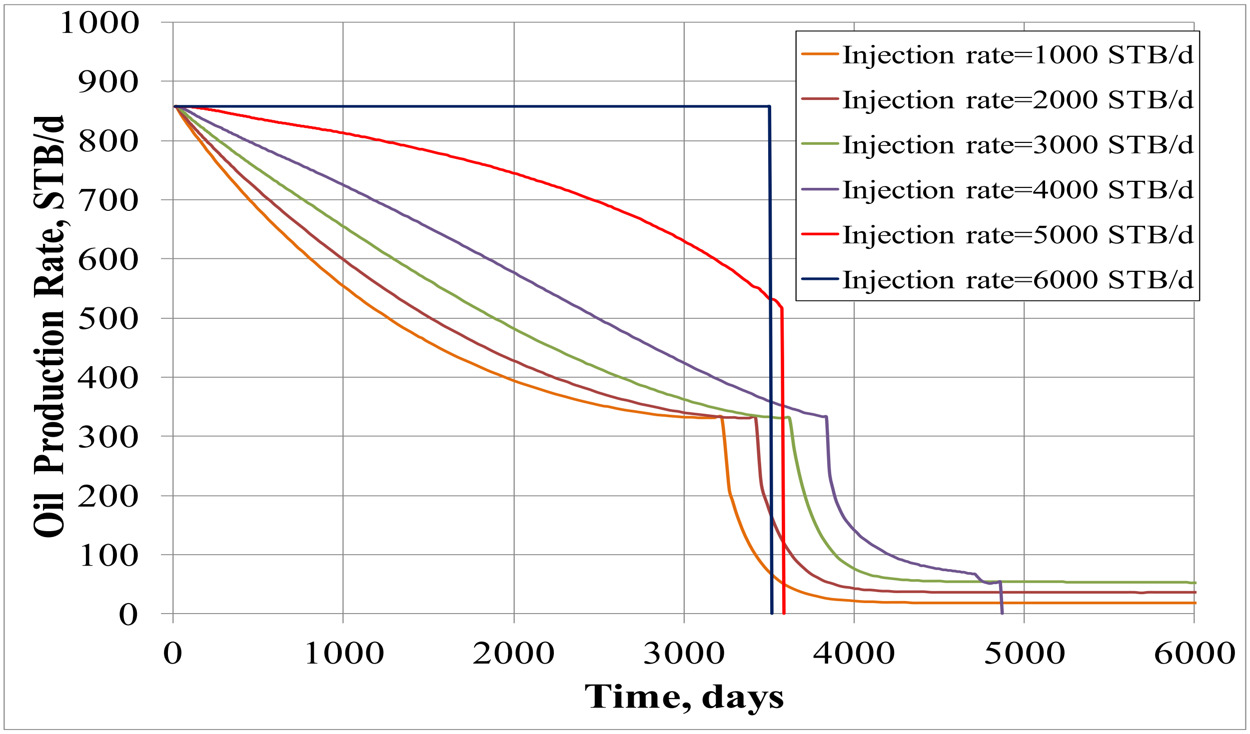


*Figure 6.7: Oil production rate comparison for different water injection rates.*

Therefore, at higher injection rates, volumetric displacement efficiency of injected water decreased and resulted in lower ultimate recoveries. In this particular case, the optimum injection rate is between 4000 STB/d and 6000 STB/d as ultimate oil recovery was high when injection rate was 6000 STB/d and ultimate gas recovery was high when injection rate was 4000 STB/d. So combination of both injection rates should be used to recover maximum hydrocarbon-initially 6000 STB/d can be injected till water breakthrough and then rate can be decreased to 4000 STB/d to re-mobilize or avoid the trapping of gas. This optimum combination rate may result in effective depressurization of the reservoir and helps in producing maximum ultimate recoveries.

## 6.3 Development of Gas Condensate Reservoir

### 6.3.1 Estimation of Water Injection Rate for Full Pressure Maintenance

Initially, the injection rate which would maintain the reservoir pressure to its initial condition is determined. The purpose of maintaining the reservoir pressure to its initial level is to avoid condensate drop out in the reservoir. Again, the injection well is placed on injection from the first day and injected till production well reached its economical limit. Economical limits and well bore constraints are same as defined in the table 6.3.

Figure 6.8, compares the reservoir pressure variation under different injection rate.

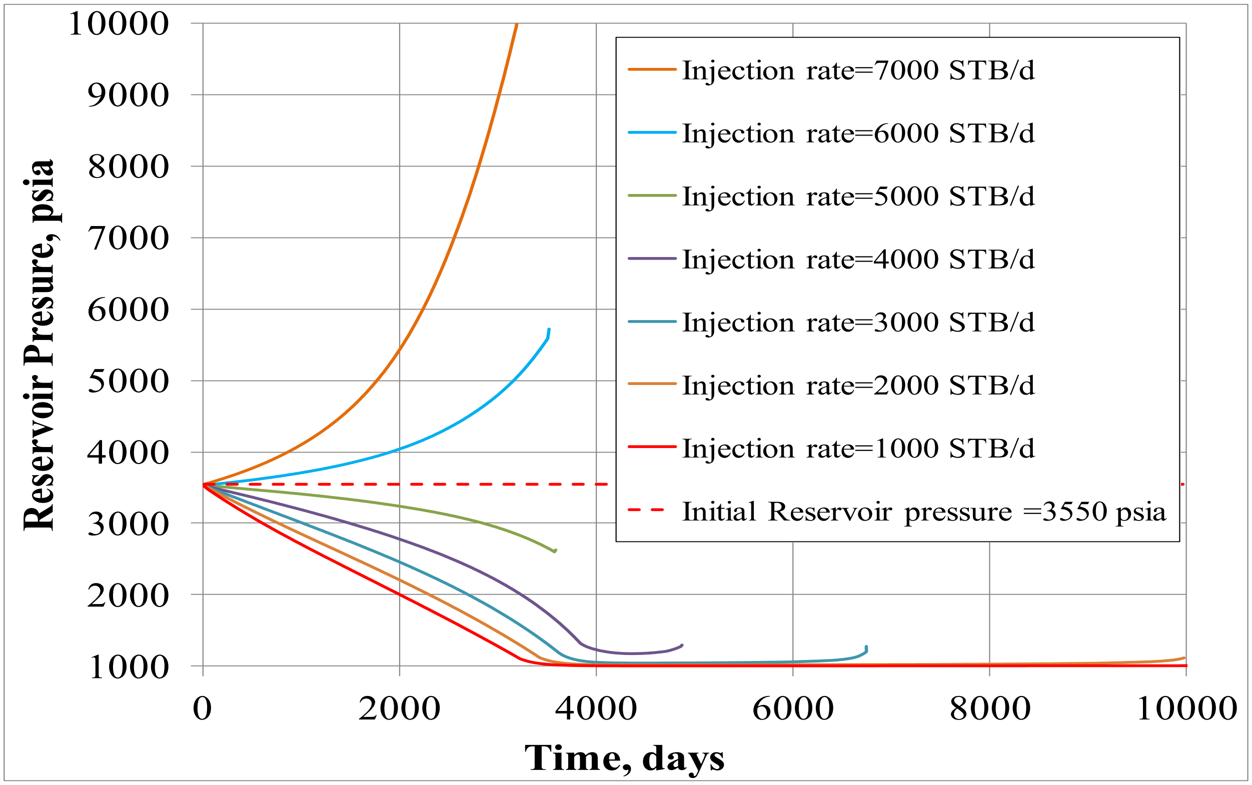


*Figure 6.8: Average reservoir pressure for different water injection rates.*

Form figure 6.8, it can be seen that above 6000 STB/d, mass of water injected is higher than the mass of fluid produced so the reservoir pressure is always increasing, and at abandonment conditions the reservoir pressure is much higher than the original reservoir pressure. In reservoir, there is always an upper limit of increased pressure to avoid the fracturing of the reservoir and this upper limit should always be considered before designing injection rate for any waterflooding project.

Below 5000 STB/d, the mass of water injected is lower than mass of fluid produced so reservoir pressure is always decreasing and at abandonment conditions, reservoir pressure is much lower than the initial reservoir pressure.

The injection rate which is required to maintain the reservoir pressure to its initial condition is between 5000 STB/d and 6000 STB/d.

Figure 6.9 shows the reservoir pressure variation along-with gas and oil production when water was injected at the rate of 5500 STB/d.

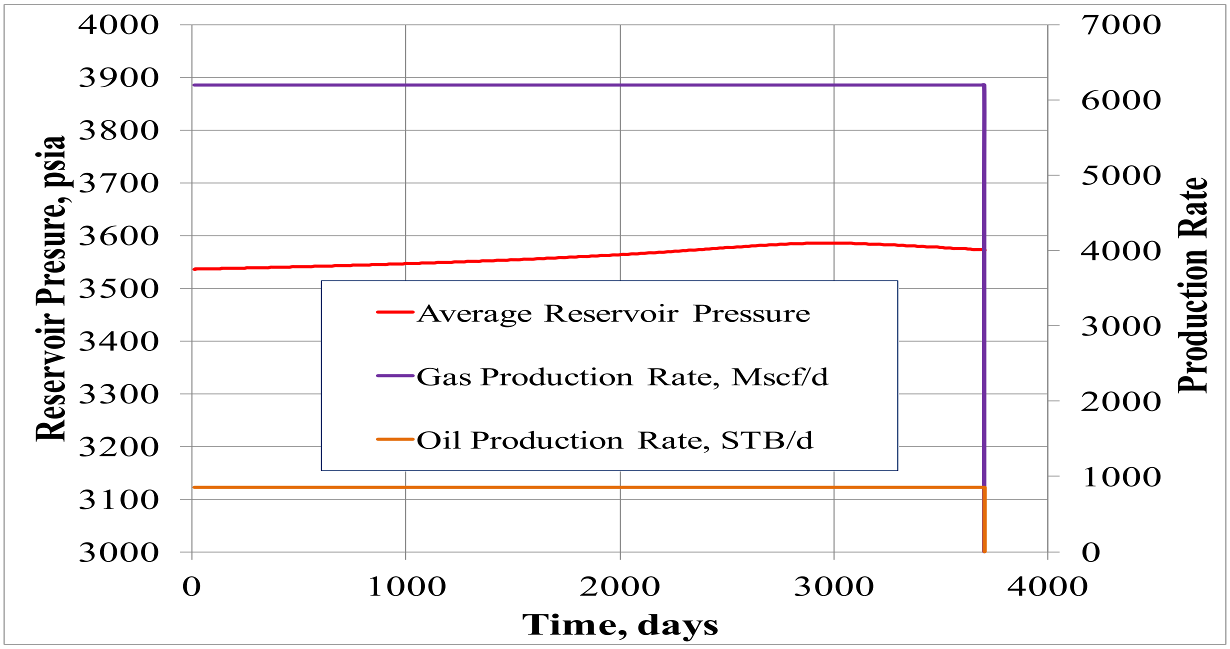


*Figure 6.9: Reservoir performance for 5500 STB/d of water injection.*

Form figure 6.9, it is clear that reservoir pressure remained constant throughout the producing life of the field which has also maintained the gas and oil production rate. Reservoir has higher hydrocarbon production rate under full pressure maintenance condition as no condensate dropped in the reservoir because reservoir pressure never fall below the dew point pressure. Moreover, both ultimate gas and oil were same and equal to 83%. But, reservoir was abandoned at its initial pressure because of water breakthrough as shown in figure 6.10. Note that water cut did not rise very high as maximum water production rate limit was 100 STB/d and when well was shut in, the oil production rate was maintained at its initial value showing that until all production layers were watered out the top layers were still producing oil at initial rate.

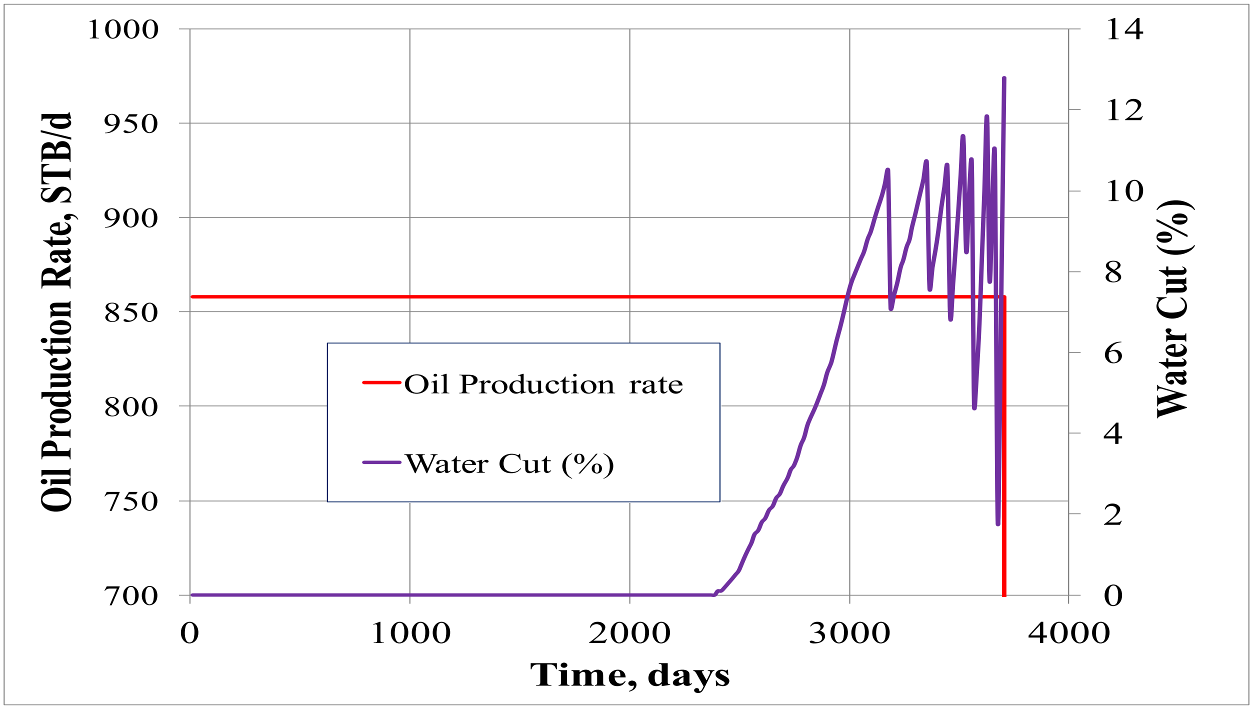


*Figure 6.10: Oil production rate and water cut for full pressure maintenance.*

### 6.3.2 Full Pressure Maintenance during Initial Production

To improve the ultimate recoveries of oil and gas, different water injection strategies were tested in different simulation runs. The injection well is injecting water at the constant rate of 5500 STB/d in all the runs and both production and injection well are started from the first day. The different runs are summarized below:

1 Water is injected for two years.
2 Water is injected for four years.
3 Water is injected till water breakthrough.
4 Water injection rate decreased to 1000 STB/d after water breakthrough.
5 Water injection rate decreased to 3000 STB/d after water breakthrough.
6 Water is injected till field abandonment conditions.

Figure 6.11 to 6.15 compares the performance of reservoir under different runs. Table 6.4 summarizes the important results from the figures and table 6.5 gives the details of volume of water injected in different runs.

From figures, it can be seen that run 1 and 2 are worst cases as reservoir pressure is not maintained causing oil to condense in the reservoir. Therefore, deliverability of well has decreased and plateau oil and gas production rates have become shorten and ultimate recoveries of oil and gas are lower than all runs. Moreover, the volumes of water injected in run 5 and 6 are lower than all the runs.

The best run for ultimate oil recovery is run 6 when water is injected till abandonment conditions. Moreover, there is no decline in gas production and oil production rate till abandonment conditions. However, Run 6 has higher abandonment pressure and lower field production time and because of this higher abandonment pressure, the ultimate recovery of oil is higher and ultimate gas recovery is lower than run 3 and 4.

The best run for ultimate gas recovery is run 4-when water injection rate decreased to 1000 STB/d after water breakthrough. But, field production time is quite high-around 10000 days so net present value of this particular case is low. Therefore, this water injection strategy is not economical.

Ultimate gas recovery of run 3-when water injection is stopped at the time of water breakthrough, is higher than run 6 but oil recovery is low and field production time is neither too low nor too high. Moreover, the volume of water injected in run 3 is much lower than run 6-54% of HCPV as compared to 84% of HCPV. There is no decline in gas production rate but oil production rate declined. The water cut in run 3 is higher than run 6 indicating that oil production rate from the top layers decreased and well produced long after the water breakthrough unlike run 6. Note that for designing any water flooding project, the amount of water injected are also considered along-with oil and gas recoveries during the economical analysis.

Based on above discussion, the best runs are either 3 or 6. Therefore, water should be either injected till field abandonment conditions to maintain the reservoir pressure above the dew point to recover maximum oil or water injection well should be shut in when water broke into the production well to prolong the field production- to increase the gas recovery. If water injection continued till the abandonment conditions, some of the gas will be trapped in the reservoir. So in order to mobilize the trapped gas, the water injection can be stopped at the time of breakthrough or some time before water breakthrough. However, stopping of water at breakthrough will increase gas recovery but will decrease oil recovery as happened in these particular cases-run 3 and run 6. 5) The richness of gas will then be an important factor to decide when to go for de-pressurization during waterflooding at full pressure maintenance. If gas has large dissolved oil, priority of recovering maximum liquid overcomes the priority of recovering gas and thus no need for de-pressurization at water breakthrough.

One Important point can also be noticed that ultimate recoveries from all runs (table 6.4) are higher than the base case (table 6.2). Hence, water drive always resulted in higher condensate recovery and improved deliverability than only depletion (base case). Moreover, full pressure maintenance till abandonment conditions increased ultimate oil recovery and partial pressure maintenance (shut in water injection well after sometime) increased ultimate gas recovery.

*Table 6.4: Performance comparison of different runs of initial full pressure maintenance.*

| Run No. | Ultimate oil recovery (%) | Ultimate gas recovery (%) | Field abandonment pressure (psia) | Field production time (days) |
|---|---|---|---|---|
| run 1 | 49.1 | 76.1 | 1003 | 4075 |
| run 2 | 59.3 | 81 | 1004 | 4255 |
| run 3 | 72.3 | 87.3 | 1005 | 4590 |
| run 4 | 76.8 | 96.6 | 1151 | 10599 |
| run 5 | 73.7 | 81.7 | 2082 | 3650 |
| run 6 | 83 | 83 | 3572 | 3705 |

*Table 6.5: Water volume injected in different runs of initial full pressure maintenance.*

| Run No. | Cumulative water injected (MRB) | Cumulative water injected in terms of HCPV (%) |
|---|---|---|
| run 1 | 4015 | 16.45 |
| run 2 | 8055 | 32.9 |
| run 3 | 13200 | 54.10 |
| run 4 | 21438 | 87.87 |
| run 5 | 17022 | 69.77 |
| run 6 | 20439 | 83.78 |

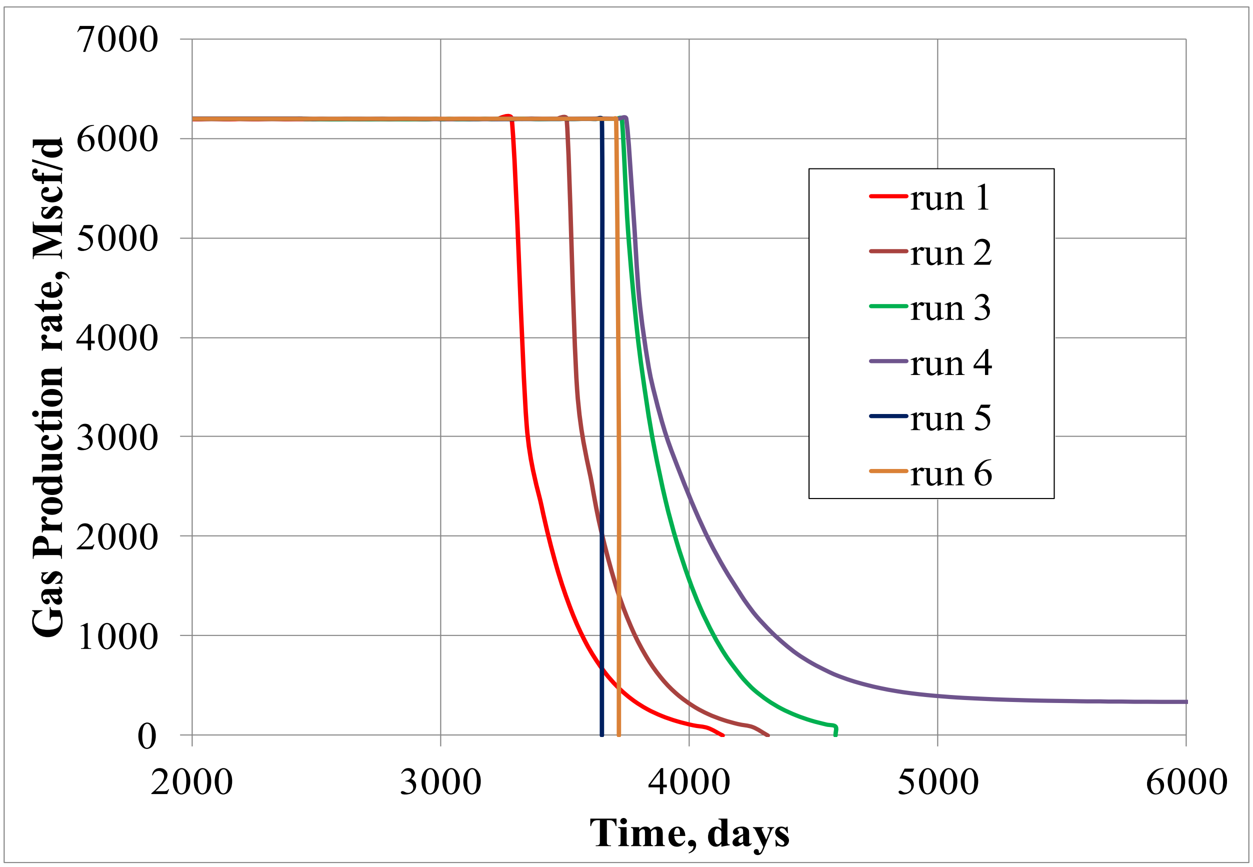


*Figure 6.11: Gas production rates for initial full pressure maintenance runs.*

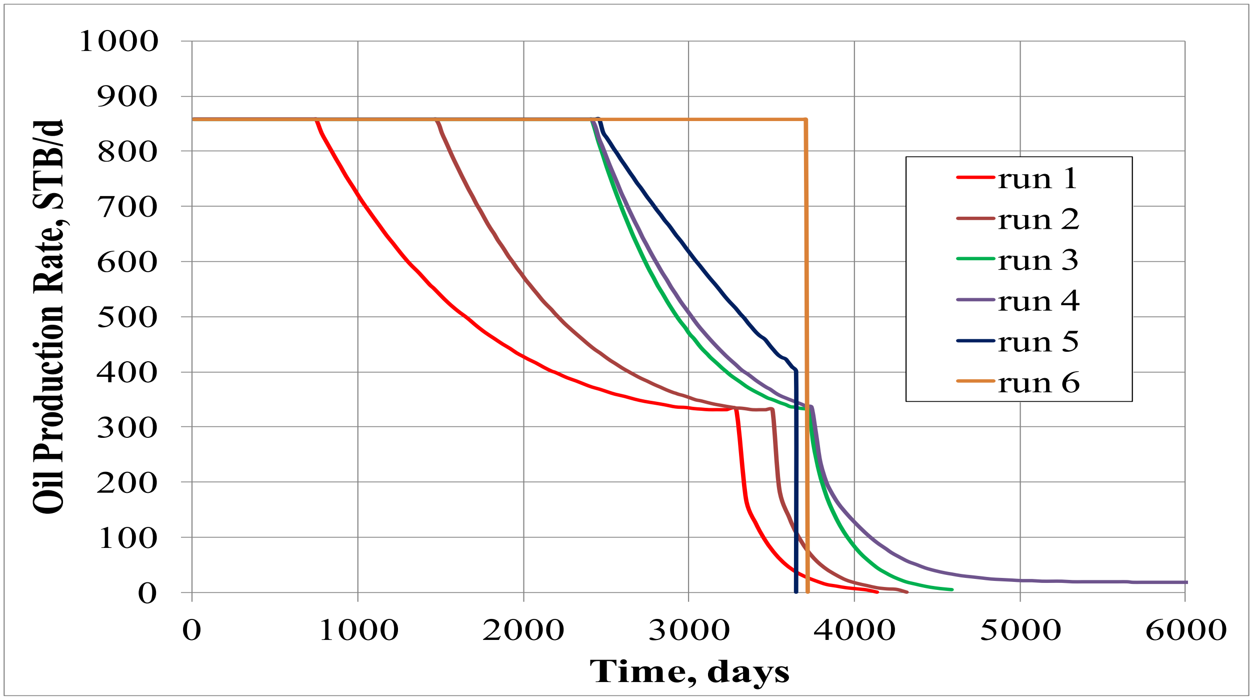


*Figure 6.12: Oil production rates for initial full pressure maintenance runs.*

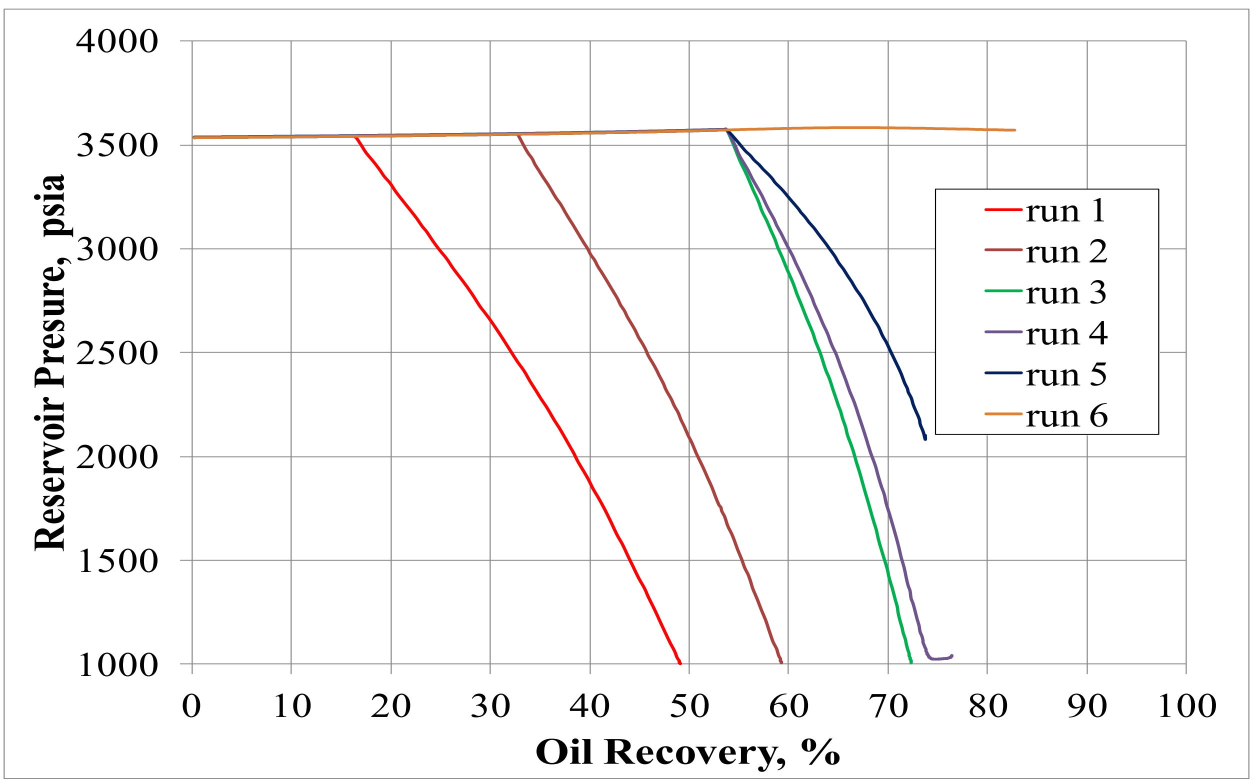


*Figure 6.13: Oil recovery vs reservoir pressure for initial full pressure maintenance runs.*

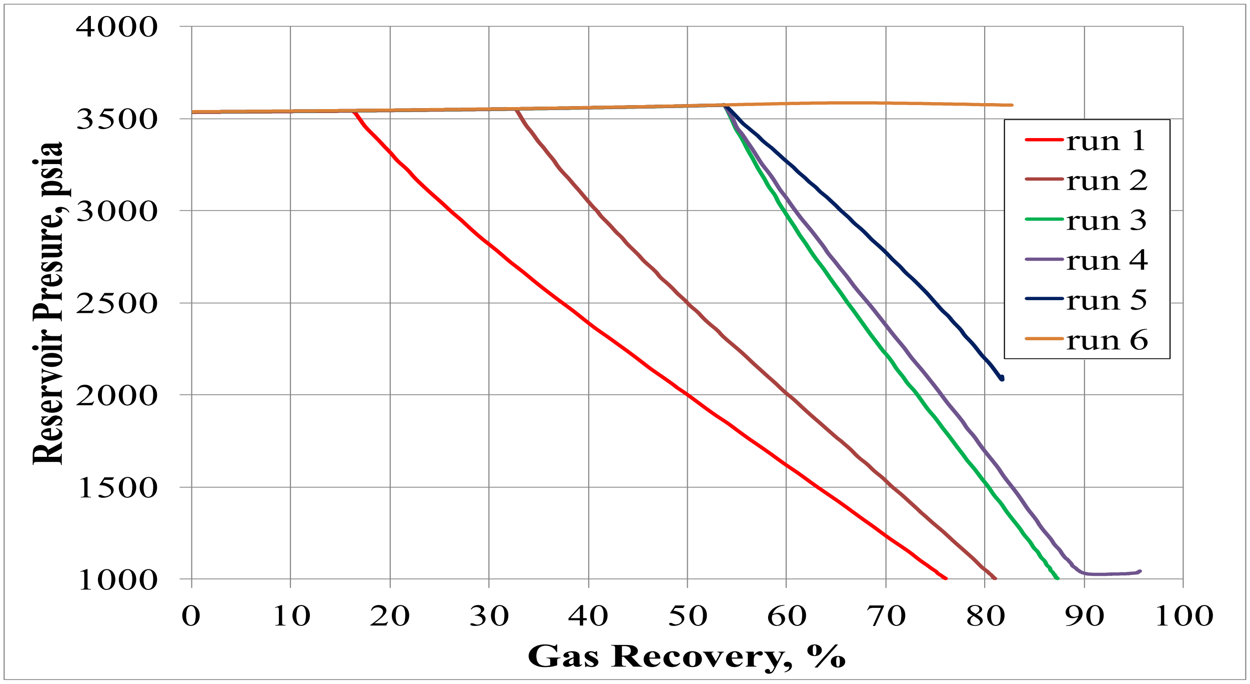


*Figure 6.14: Gas recovery vs reservoir pressure for initial full pressure maintenance runs.*

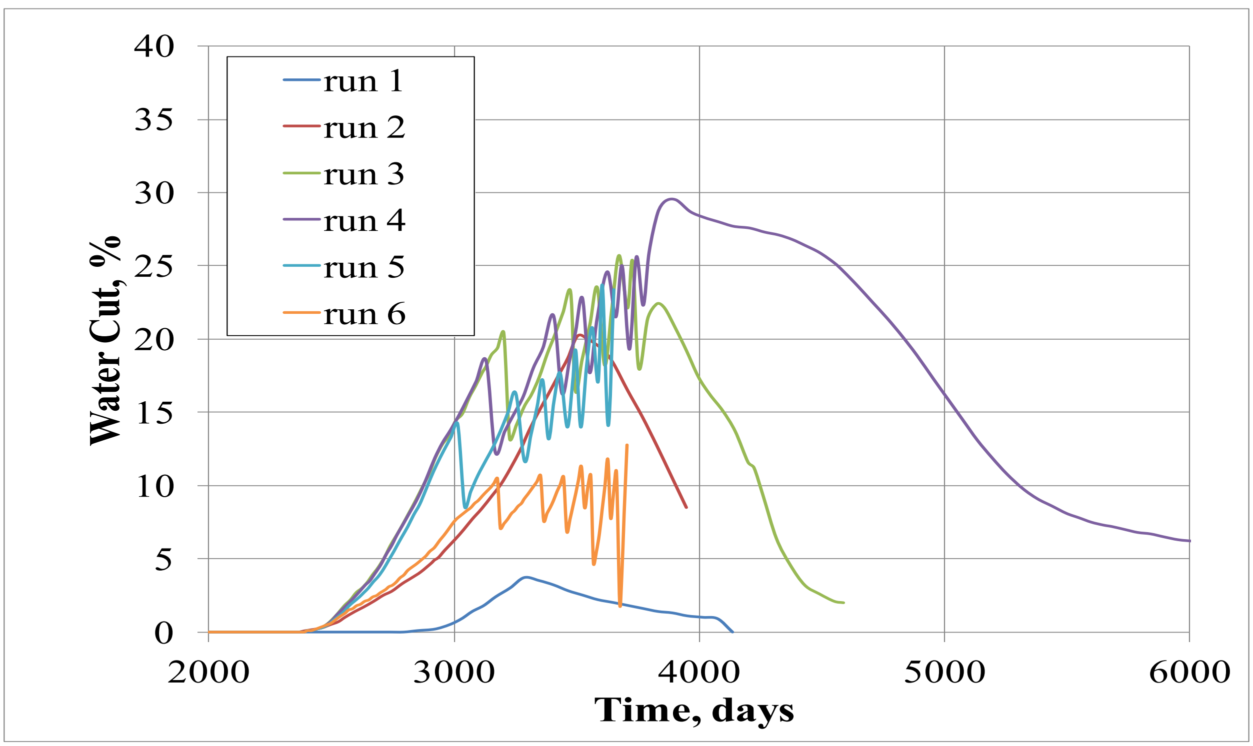


*Figure 6.15: Water cut for different initial full pressure maintenance runs.*

### 6.3.3 Partial Pressure Maintenance

This case is designed assuming limited water available for water injection. As has explained previously, the injection of water below 5500 STB/d would result in partial maintenance of reservoir pressure in this particular case. Injection rate of 3000 STB/d is selected for developing the field under partial pressure maintenance

Following simulation runs are made:

1 Water injection stopped after two years of injection
2 Water injection stopped after four years of injection.
3 Water injection stopped after the water breakthrough
4 Water is injected till field abandonment conditions

Figures 6.16 to 6.19 summarize the results from this case.

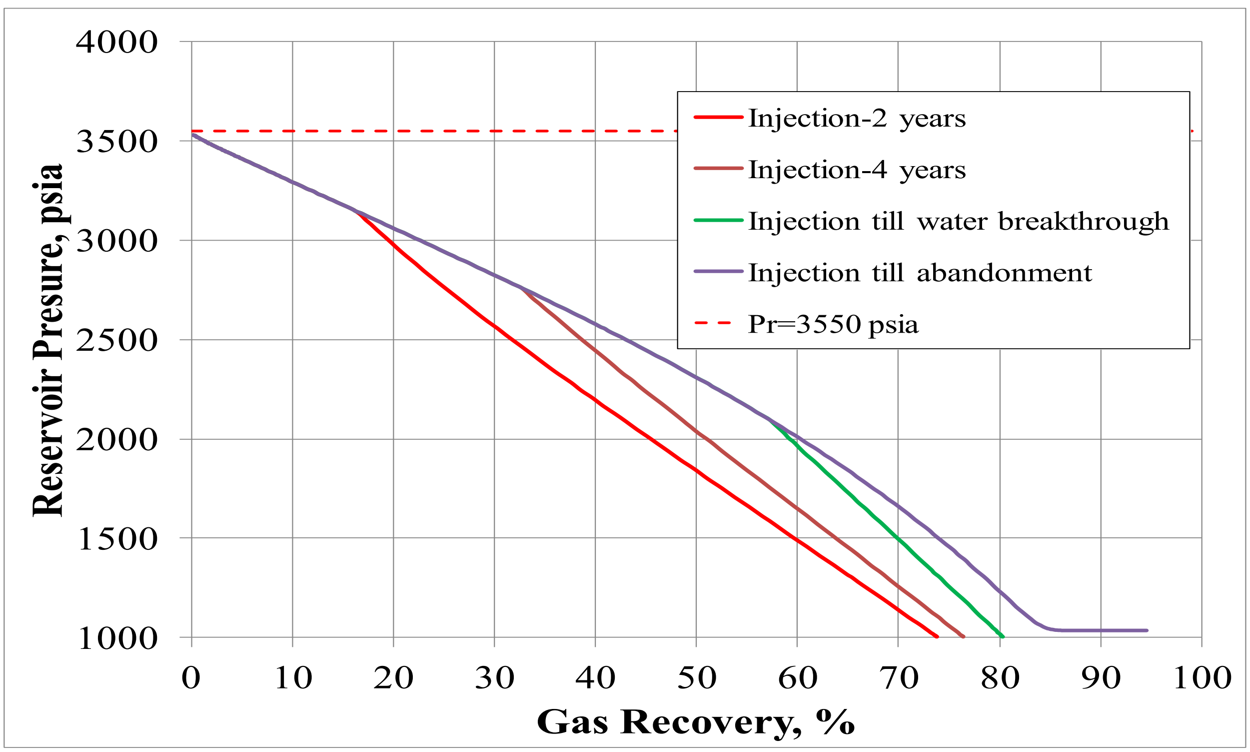


*Figure 6.16: Gas recovery vs reservoir pressure for partial pressure maintenance runs.*

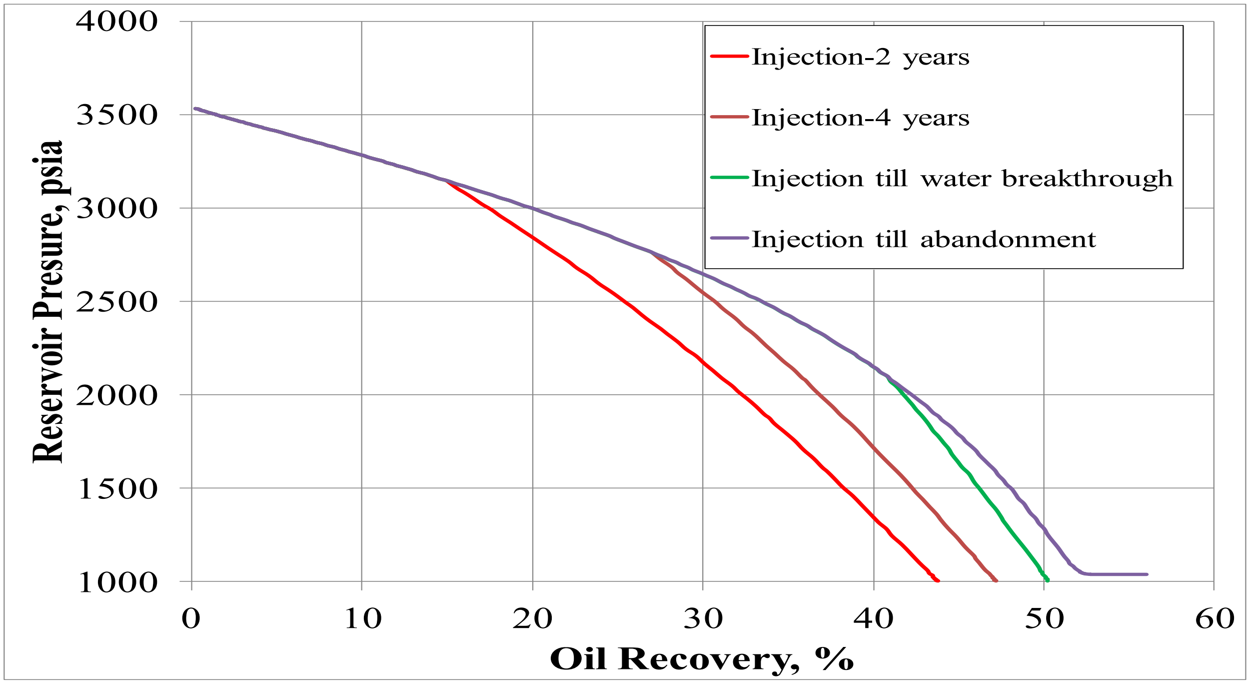


*Figure 6.17: Oil recovery vs reservoir pressure for partial pressure maintenance runs.*

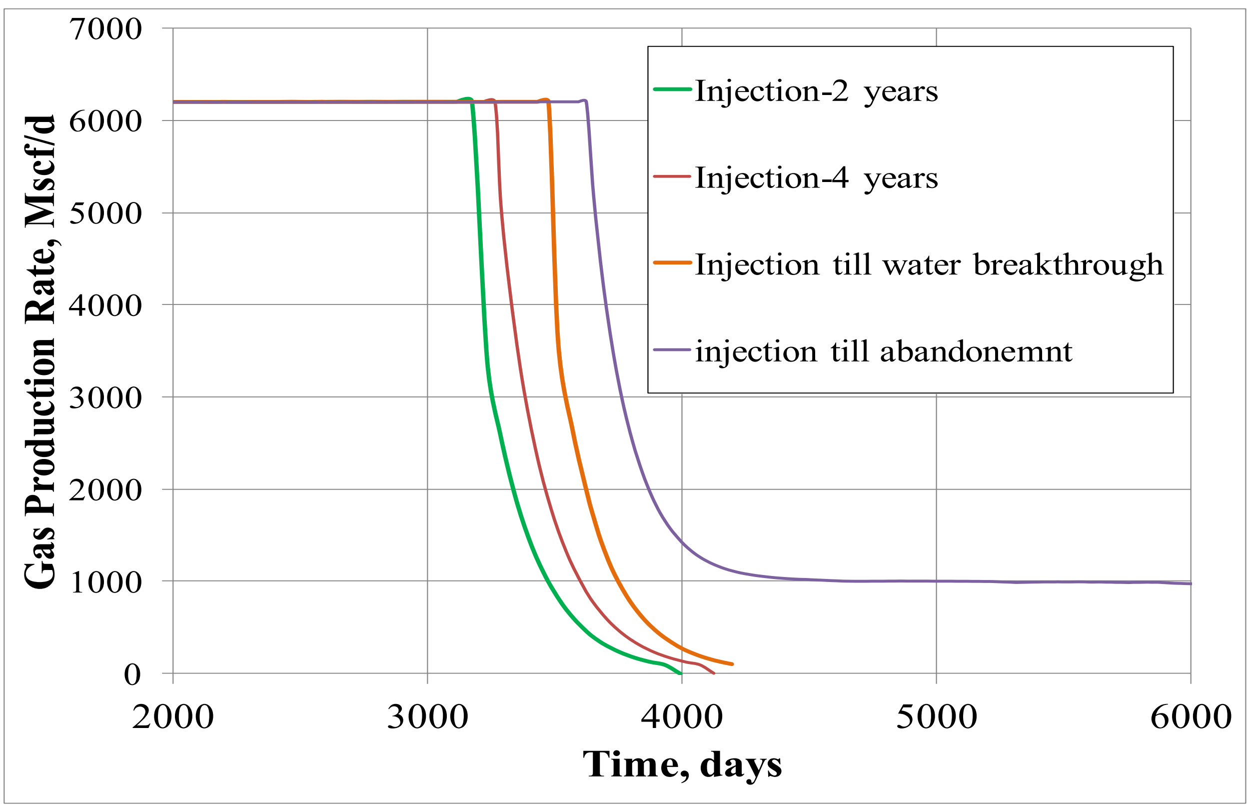


*Figure 6.18: Gas production rates for partial pressure maintenance runs.*

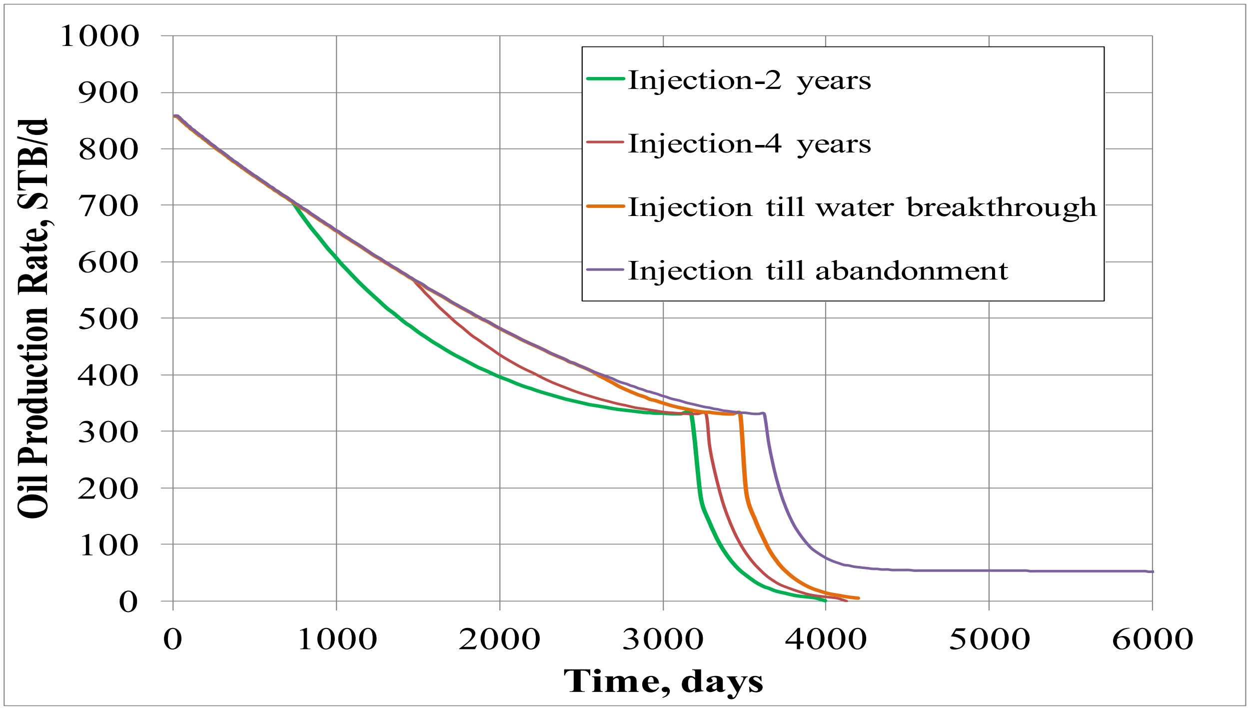


*Figure 6.19: Oil production rates for partial pressure maintenance runs.*

It can be seen from figures that water injection till abandonment conditions has improved both ultimate gas and oil recoveries. Moreover, plateau gas production rate has been prolonged and oil production rate has also been improved.

Therefore, for partial pressure maintenance scheme, the water injected till abandonment recovered more oil and gas.

### 6.3.4 Injection at Particular Reservoir Pressure

In this case, reservoir pressure at particular value is kept constant during water injection. This is simply done in SENSOR by using the Keyword PCON. The SENSOR automatically calculates the injection rate required to maintain the defined reservoir pressure and will keep that pressure constant until production well reaches the economical limits. The following four reservoir pressure runs were made

1 Reservoir Pressure kept constant at 3550 psia
2 Reservoir Pressure kept constant at 3250 psia
3 Reservoir Pressure kept constant at 3000 psia
4 Reservoir Pressure kept constant at 2500 psia

The results are summarized in the figures 6.20 to 6.23.

From figures, again it is clear that higher the reservoir pressure at abandonment conditions, higher is the oil recovery. Gas recovery should also have decreased with the increase in reservoir abandonment pressure but reverse trend was seen-ultimate gas recovery increased slightly as reservoir pressure increased above 3000 psia. The possible reason for this increase is the increase in reservoir gas viscosity at higher reservoir pressure resulted in lower mobility and favorable mobility ratio causing water to displace more reservoir gas before breakthrough and thus resulted in higher gas recovery,

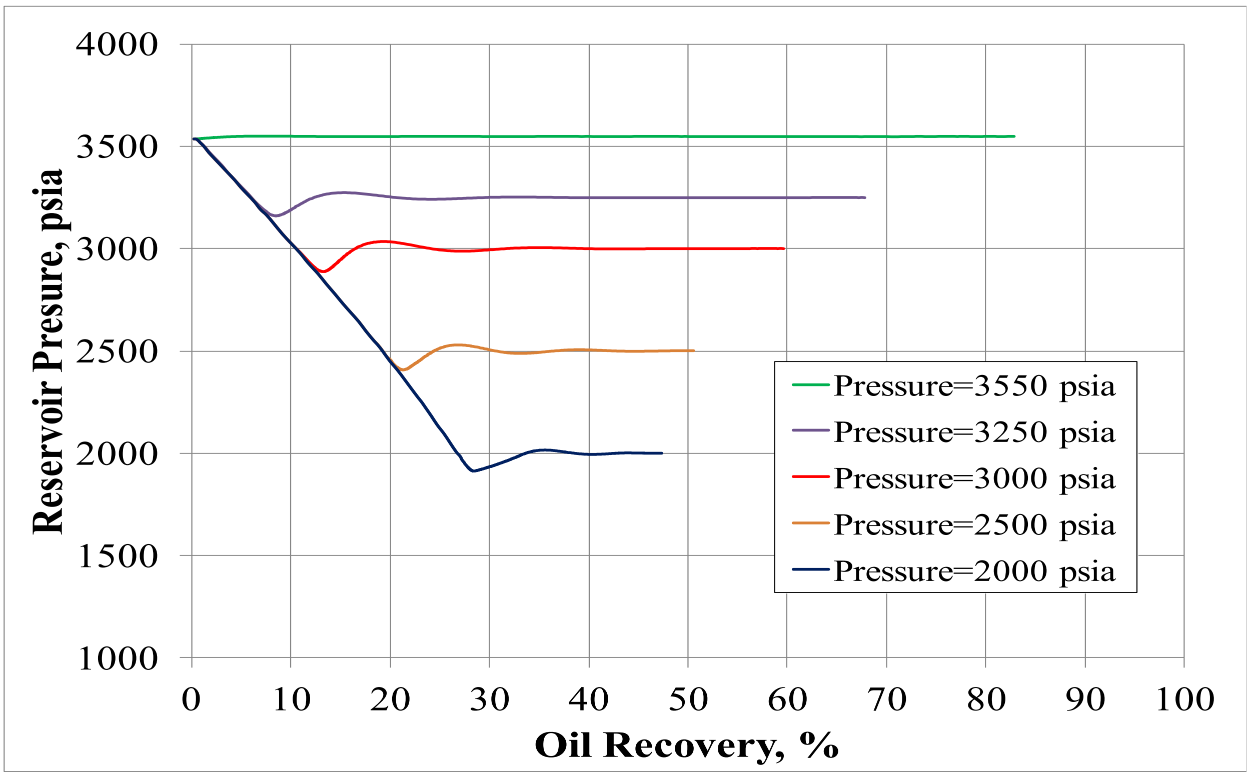


*Figure 6.20: Oil recovery vs reservoir pressure for maintenance at different reservoir pressure.*

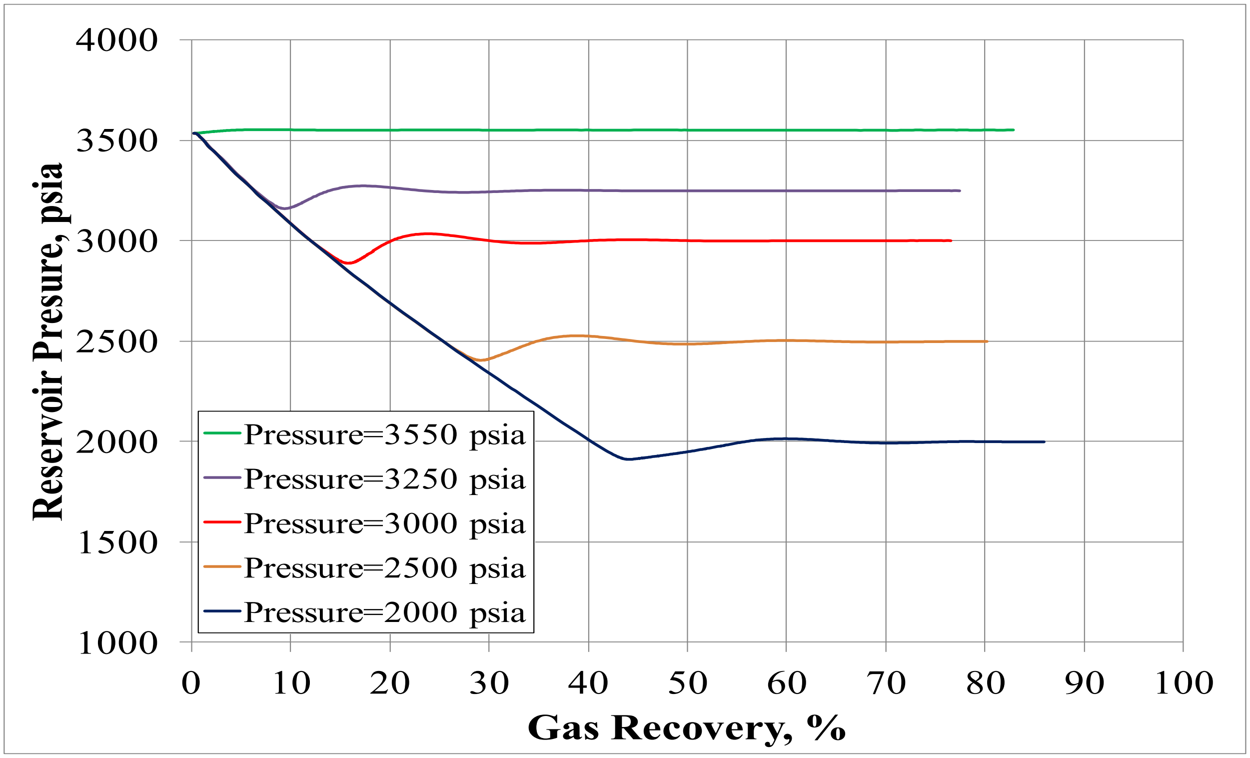


*Figure 6.21: Gas recovery vs reservoir pressure for maintenance at different reservoir pressure.*

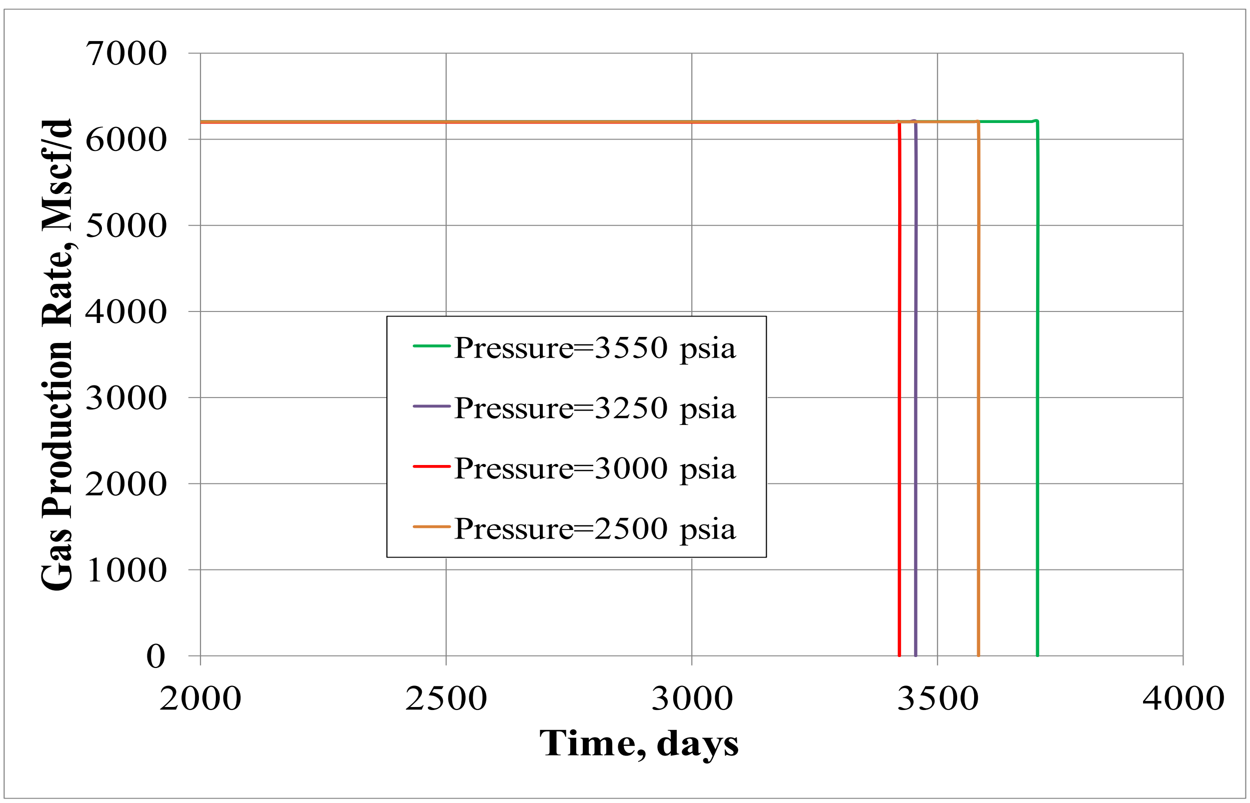


*Figure 6.22: Gas production rates for maintenance at different reservoir pressure*

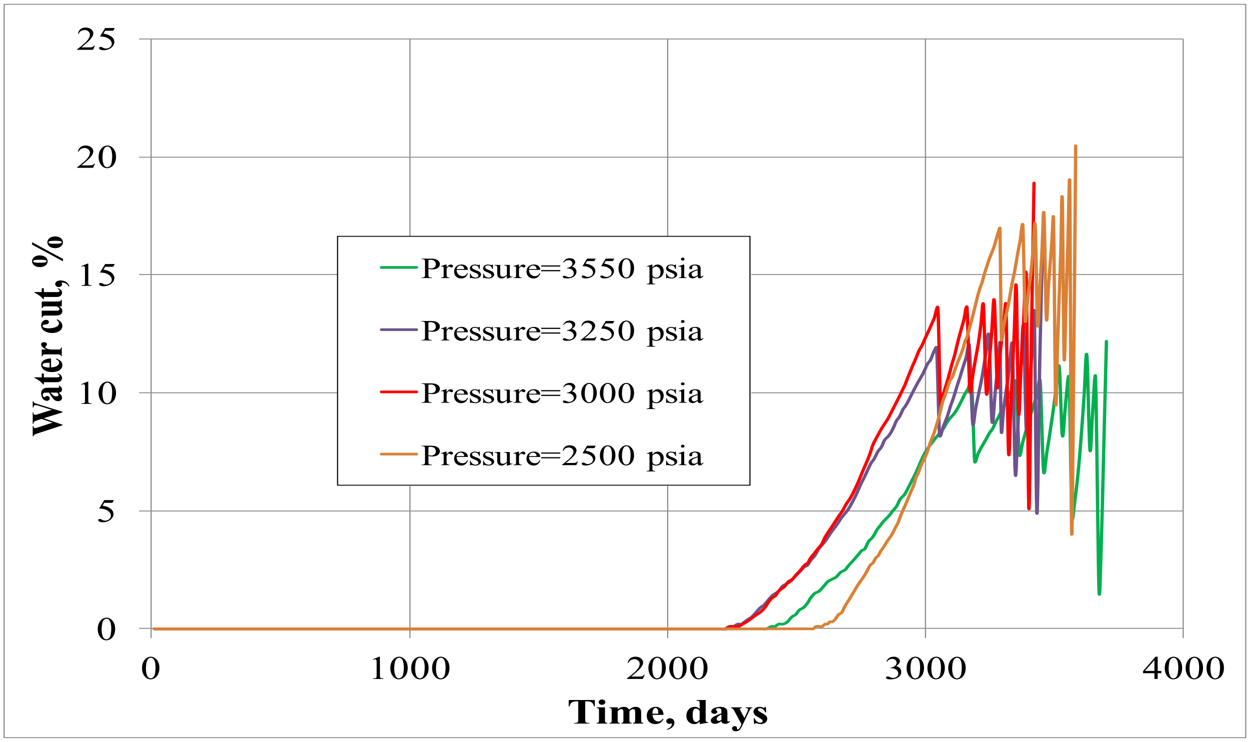


*Figure 6.23: Water cut for maintenance at different reservoir pressure*

### 6.3.5 Effect of Reservoir Permeability on Full Pressure Maintenance Water flooding

The base case has vertical heterogeneity in layers and horizontal permeability ranges from 40 mD to 150 mD. Cases are run to investigate the effect of full pressure maintenance water flooding on homogeneous permeable reservoir of 1000 mD and 10 mD. The performance is compared with the base case. The water is injected at the rate of 5500 STB/d and water is injected till abandoned conditions. Moreover, the distance between the injector and the producer is same in all runs.

It can be seen from figures 6.24 and 6.25 that field production time during waterflooding slightly decreased as reservoir permeability increased to 1000 mD because water moved quickly form injection well to production well and resulted in early breakthrough of water and larger trapping of gas. Therefore, ultimate recoveries of oil and gas are lower as compared to base case-81% for 1000 mD case as compared to 83% for base case. Therefore, duration of water injection should be carefully designed in high permeable reservoirs to extend the reservoir life and to increase ultimate recoveries.

For 10 mD case, as the production well is not in communication with injection well, the pressure near the production well decreased rapidly due to production of gas causing oil to condense from the gas so the oil production rate of low permeable case was lower than base case or high permeable case during initial days of production. After two years of oil production, the saturation of oil near wellbore was around 40%. This much liquid saturation in the reservoir has not only decreased the oil production rate but act as a formation damage zone which decreased the oil and gas production rate, significantly, after two years of production.

Surprisingly, the water broke very early in the life of the well around 440 days in 10 md case-much earlier than base case and 1000 mD case and after 1000 days, much of the bottom layers of the production well were watered out and was shut in to stop water production. Water cut of different cases have been compared in figure 6.26.

As production well comes in communication with injection well, oil production rate increased sharply around 1250 days as gas deliverability improved due to increase in pressure near well bore and also, some of oil that had been condensed out near the wellbore not only re-vaporized again back into gas phase but also displaced by water into the producing well. Oil production rate was even much higher than initial oil production rate (oil production rate expected above dew point). Note that, in this period, production well was only producing through the top three layers as the bottom of the layers were watered out.

Oil production rate again sharply decreased after 1800 days as the remaining top layers were getting water out and resulted in early shut down of the well. The well was shut in around 2300 days-much earlier than 1000 mD or base case.

The ultimate recovery of oil and gas for 10 mD case was only 43.8% -much lower than its depletion case. The advancement of water front was not uniform and had resulted in earlier breakthrough. The injected water did not sweep much of the reservoir and volumetric efficiency was low. The water only followed the low resistance area-the area where already water had passed out and did not spread to the un-swept areas. Same observation was also made by Henderson et al.[17] working on heterogeneous cores-capillary controlled imbibition of water resulted in decreased sweep efficiency and early break-through of water through the low permeable layer and by-passing of larger pores.

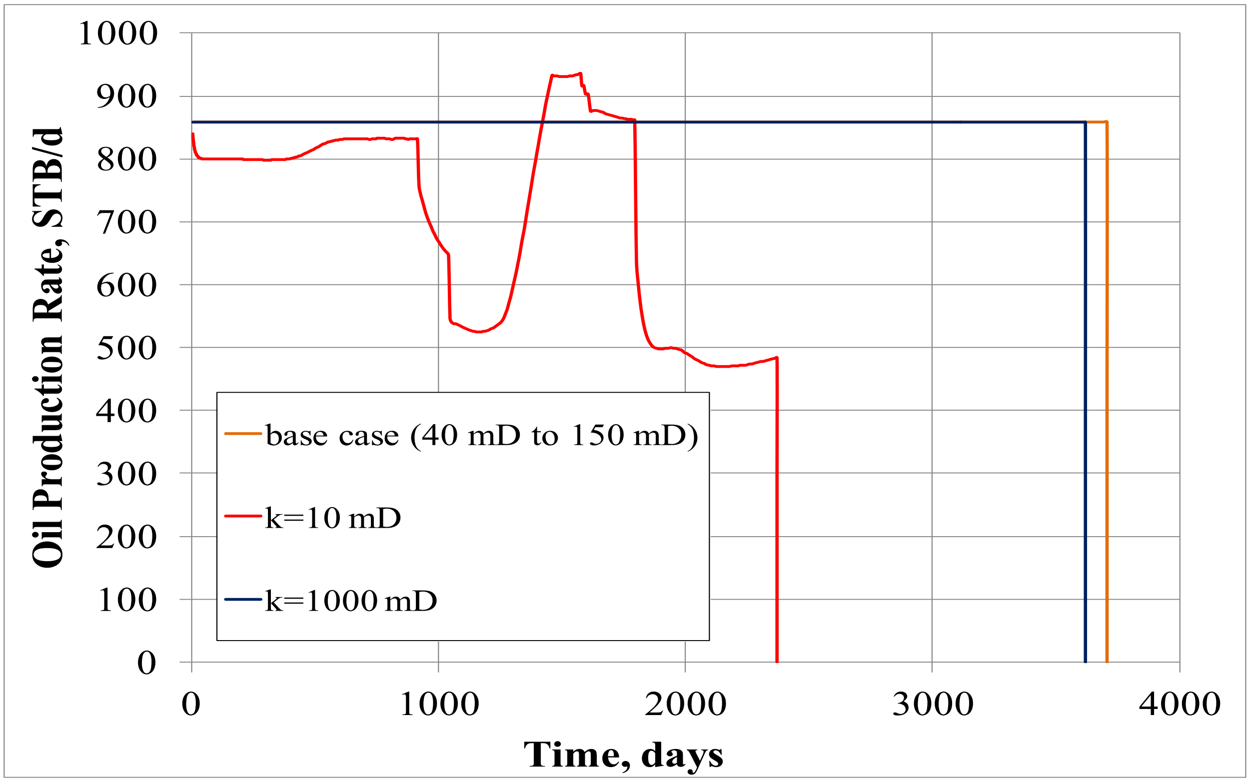


*Figure 6.24: Oil production rates for full pressure maintenance for different permeable reservoirs.*

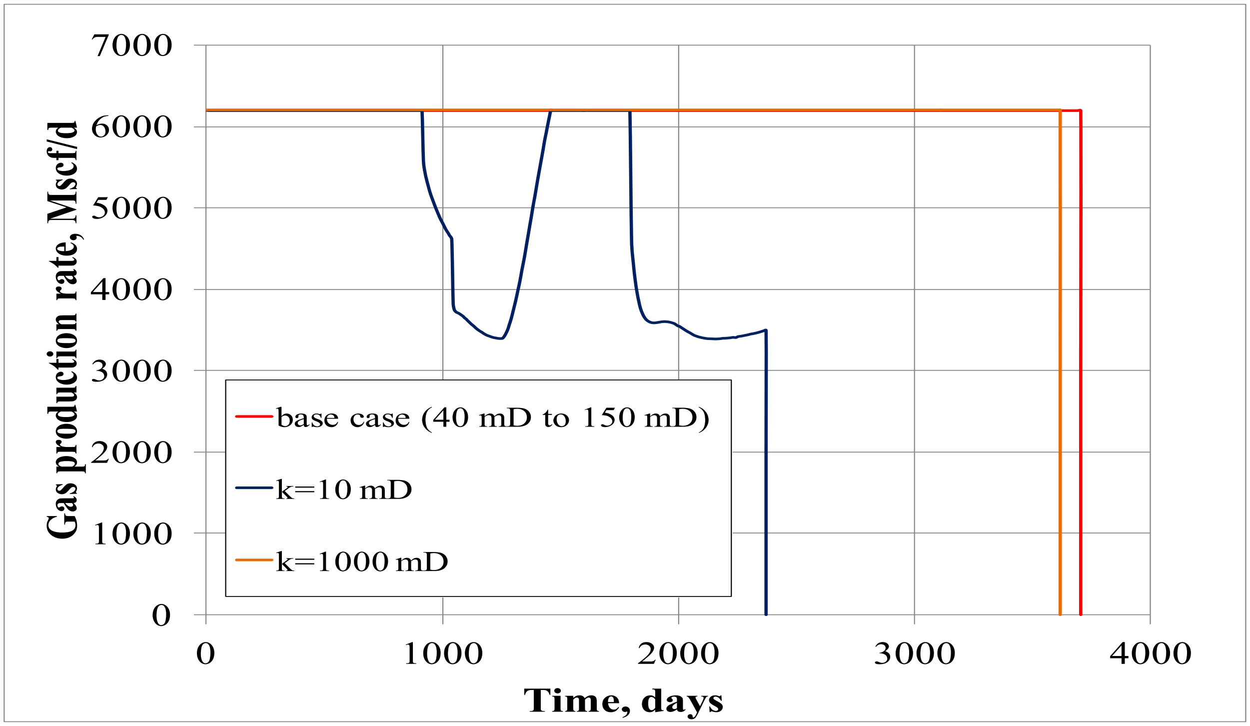


*Figure 6.25: Gas production rate for full pressure maintenance for different permeable reservoirs.*

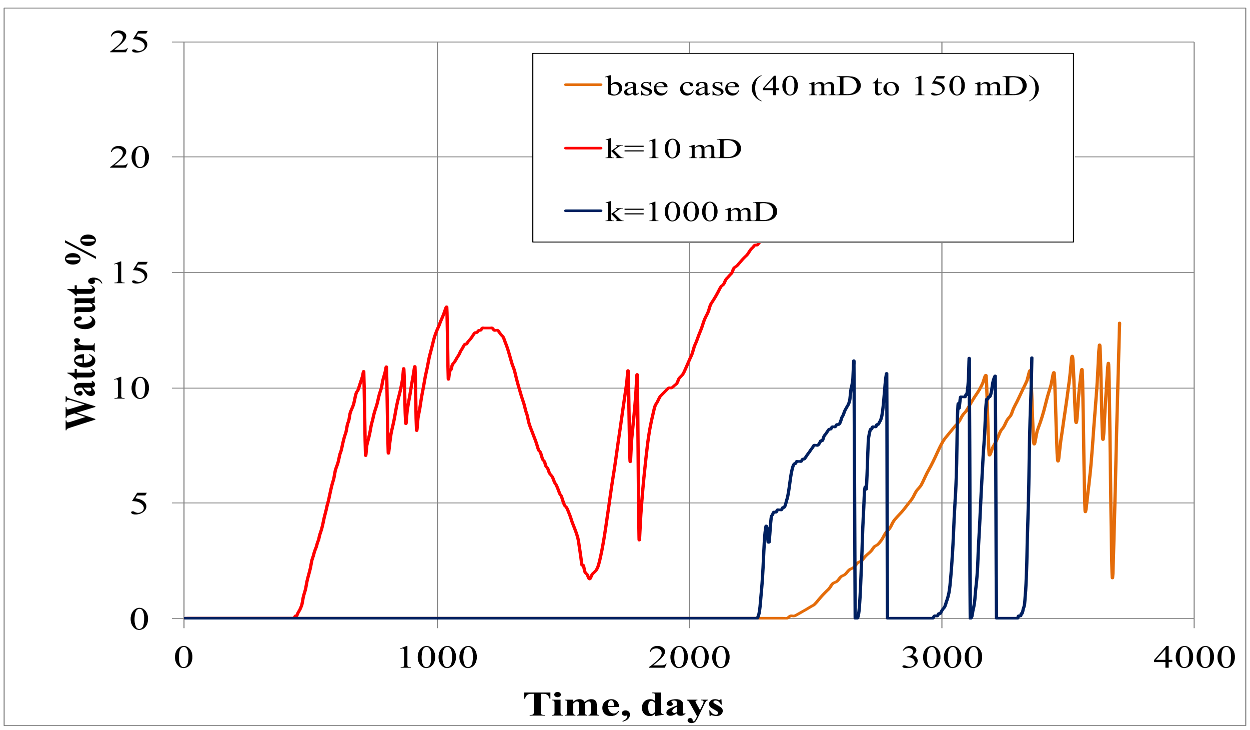


*Figure 6.26: Water cut for full pressure maintenance for different permeable reservoirs.*

Initially for 10 mD case, production well was not in pressure communication with the injection well so pressure near production well decreased significantly and pressure near injection well increased significantly. Moreover, after the bottom layers of production well were watered out, the reservoir pressure near production well increased significantly as production from top layers were quite less than the injected water.

PCON keyword is used to maintain the average reservoir pressure for 10 mD to its initial value to avoid the spikes in the production curve. As has explained above, the injection rate will be automatically calculated to maintain the pressure. The performance with and without PCON is compared. The results are shown in figure 6.27 and 6.28.

It is clear from graphs that there is no such sharp increase in oil and gas production rate around 3 years of production for the case when keyword PCON was used. Although water breakthrough occurred at similar time for both the case, the well produced longer when PCON option is used. The reason for large production time is as when bottom layers of the production well were shut due to production of water, the water injection rate decreased automatically accordance with production to ensure constant pressure in the reservoir and this decrease in injection rate further reduced the water breakthrough. The condensed oil near wellbore acted as a formation damage and reduced the well deliverability and the injected water did not re-vaporize or displaced the condensed liquid so well produced at lower production rates and this condensed liquid proved to be a permanent damage and was the cause of low deliverability.

It is clear from above discussion that for low permeable reservoirs, the pressure communication did not develop quickly so liquid that condensed out near the wellbore decreased the gas well deliverability to a great deal. Moreover, the pattern of water front is not uniform causing an early breakthrough of water. Also, higher pressure developed near injection well may cause fracturing. Therefore, well spacing between the injection and production well in low permeable reservoirs should be designed carefully to establish communication between the injection and production well. From this case it is clear that, the permeability of the reservoir has a major factor during water flooding. Too high and too low permeability reservoirs require proper designing.

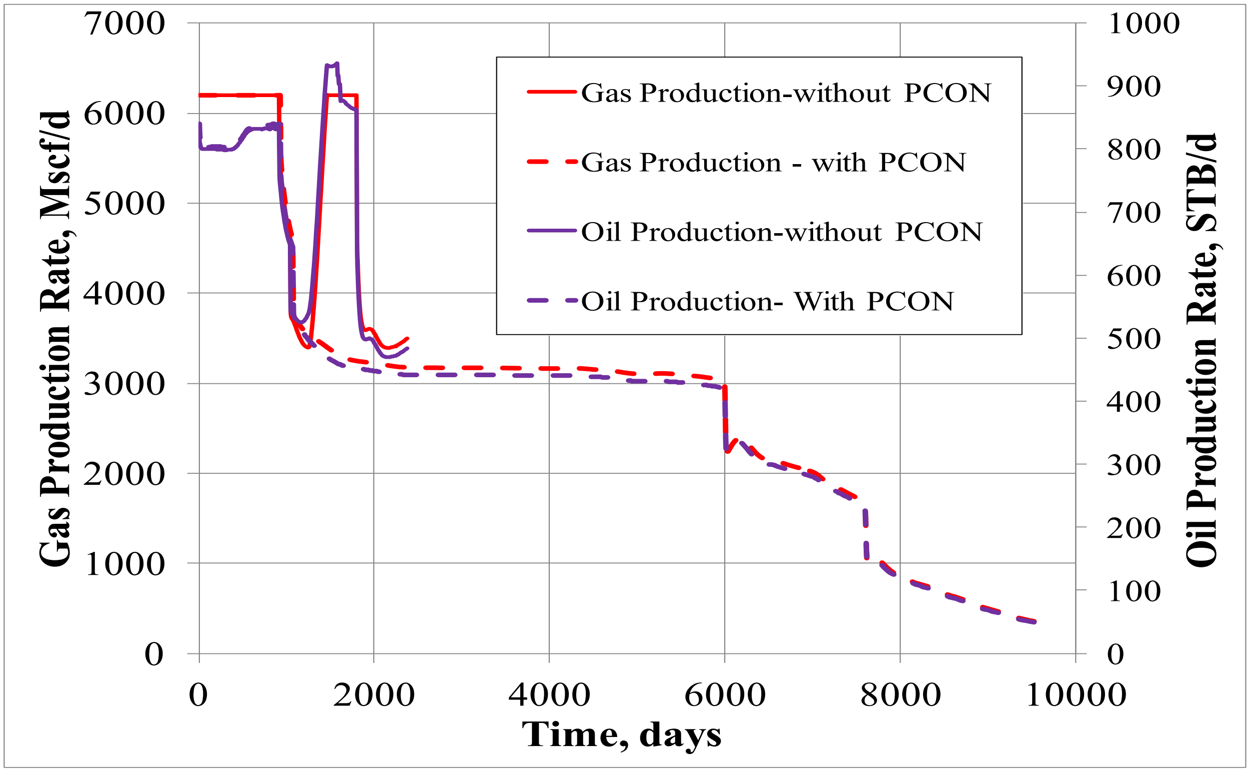


*Figure 6.27: Oil and gas production rate-with and without PCON.*

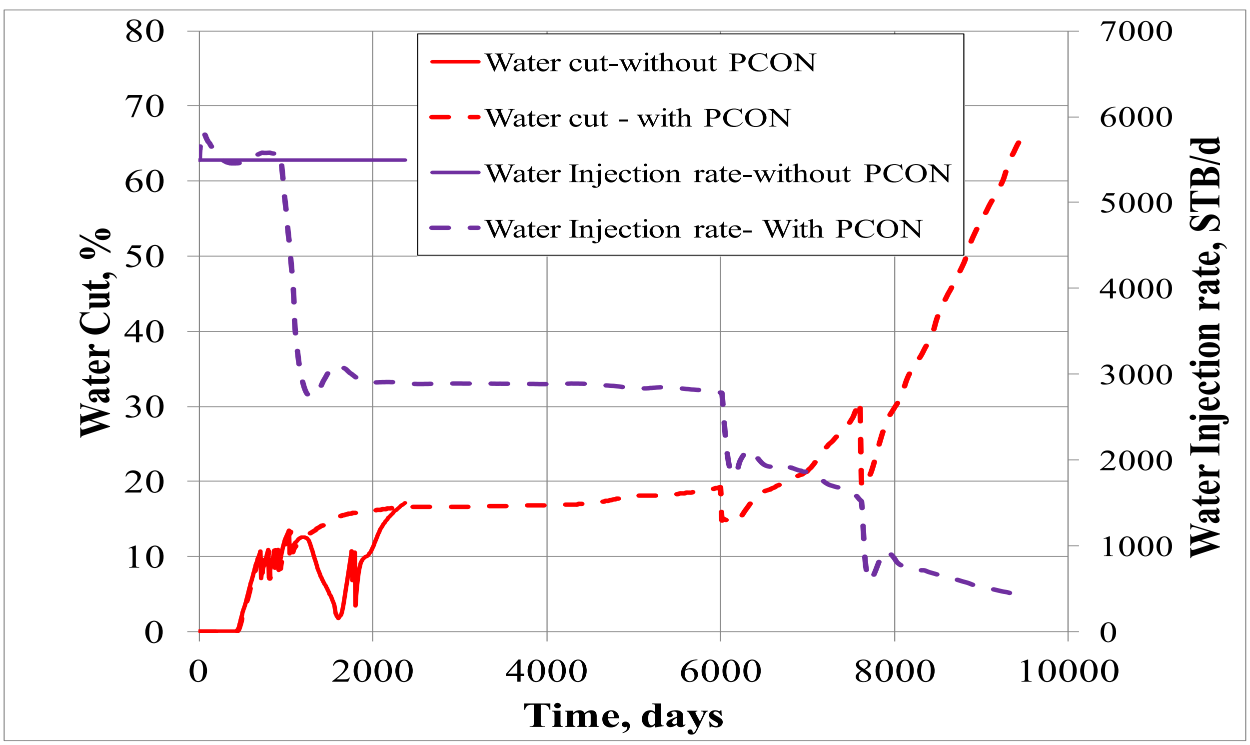


*Figure 6.28: Water Cut and water injection rate-with and without PCON.*

# 7 Conclusions

The idea of water influx and water flooding in gas condensate reservoir has been reviewed in this thesis and important results from the study are summarized below:

1) Pressure support from water influx and/or water injection can significantly increase ultimate oil and gas recoveries from a gas condensate reservoir.
2) Rapid breakthrough of water from the large size aquifer and high water injection rate caused large trapping of gas at higher reservoir abandonment pressure.
3) If size of aquifer is quite large then pay zone size, it is possible to initially take full advantage of maintenance of reservoir pressure to recover maximum liquid followed by rapid de-pressurization to recover maximum gas.
4) Water injection rate is very important during waterflooding of a gas condensate reservoir to optimize total hydrocarbon recovery during waterflooding. Liquid recovery is low and gas recovery is high at low injection of water as reservoir pressure is partially supported but at high injection of water, recovery of liquid is high and recovery of gas is low.
5) The richness of gas dictates when to go for de-pressurization during initial full pressure maintenance waterflooding. If gas has large dissolved oil, priority of recovering maximum liquid overcomes the priority of recovering gas and thus no need for de-pressurization at water breakthrough.
6) The lift capacity of the well is very important and by increasing the lift capacity, hydrocarbon recovery from that particular well can also be increased.
7) For reservoir with large aquifer size, piston like displacement with high ultimate recoveries can be achieved by producing at low gas production rates. Increase in field production time at such low rates may decrease the net present value and makes it un-economical to apply.
8) Initially producing the well at higher gas rate followed by low gas rate can significantly increase the ultimate oil and gas recoveries when an active aquifer is encroaching into

pay zone. Timing of changing rate from high rate to low rate has found to affect the reservoir performance greatly.

9) Water production well can help in rapid de-pressurization of the reservoir to recover maximum trapped gas. The timing and location of the water production well and water production rate need to be designed carefully.
10) Regardless of the size of aquifer, the influx of water is not sufficient to maintain reservoir pressure above dew point pressure if reservoir fluid is slightly under saturated. In such case, water can be injected in the aquifer to maintain the reservoir pressure above dew point.
11) Aquifer with lower vertical permeability does not support the production from pay zone which results in higher gas recovery and lower oil recovery then with aquifer having higher vertical permeability.
12) In low permeability reservoirs, the dropped condensate decreased the gas well deliverability drastically. Moreover, the dropped condensate is difficult to re-vaporize again during water flooding as communication between injection and production well is hard to establish. Therefore, well spacing need to be designed carefully.
13) At higher initial reservoir pressure and with moderate aquifer, the ultimate gas and recovery was found independent to further increase in size of aquifer. This is due the extra displacement of gas by water due to increase in viscosity of gas at higher initial reservoir pressure resulted in almost same amount of trapped gas although aquifer size was increased.

# Limitations and Future Work

The results presented in this thesis should only be used qualitatively as only simple simulation models of gas condensate reservoir have been used without performing any history matching or laboratory tests. Moreover, only single set of relative permeability data have been used both in water invasion and blow down period but for proper investigation of gas recovery during blow down period, new set of relative permeability data with different critical gas saturation then trapped gas saturation is required. Also, only effect of bottom water drive has been studied in this thesis. The effect of capillary forces and velocity dependent relative permeability are not considered in this study assuming that their consideration will not affect the results too much. Water flooding in low permeable reservoir should also be investigated thoroughly.

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# Appendix A

```
TITLE
SIZE OF AQUIFER TEN TIMES THEN RESEVOIR SIZE
RADIAL MODEL FOR WATER AQUIFER STUDIES
AT SURFACE, SELL GAS HAS ALL C4- AND LIQUID HAS ALL C5+
RELATIVE PERMEABILITY DATA FROM COREY CORRELATION
ENDTITLE

GRID   40 1 88
MISC   1.   3E-6    63.    .7    5E-6   3550 !    Bwi cw dw vw cr pref
IMPLICIT
RUN

C ------------------------------------------------------------------------------------
C Rock relative permeabilities
C ------------------------------------------------------------------------------------
KRANALYTICAL 1
 0.16     0.3    0.124   0.0     ! Swc  Sorw  Sorg  Sgc
 0.380   0.556   0.8             ! krw(Sorw)  krg(Swc,Sorg)  kro(Swc)
 2.2       2.8    1.9     3.4     ! nw now ng nog

RADIAL
  1           ! grid sizes are generated automatically - equal spacing in log(r)
  1  1490   ! well radius and outer radius of drainage area
 360         ! model full 360 deg round well

THICKNESS ZVAR
  10 10 10 10 10 10  16.67 16.67 16.67  16.67 16.67 16.67
  20 20  20 20  20 20  20 20  20 20  20 20  20 20  20 20
  20 20  20 20  20 20  20 20  20 20  20 20  20 20  20 20
  20 20  20 20  20 20   20 20 20 20  20 20  20 20  20 20
  20 20  20 20  20 20  20 20  20 20  20 20  20 20  20 20
  20 20  20 20  20 20  20 20  40 40  40 40

POROS CON
  0.13

DEPTH CON
 7315

KX ZVAR
 130  130  130  40  40  40  20  20  20  150  150  150
 100  100  100  100  100  100  100  100  100  100  100  100  100  100  100  100
 100  100  100  100  100  100  100  100  100  100  100  100  100  100  100  100
 100  100  100  100  100  100  100  100  100  100  100  100  100  100  100  100
 100  100  100  100  100  100  100  100  100  100  100  100  100  100  100  100
 100  100  100  100  100  100  100  100  100  100  100  100
```

```
KY EQUALS KX


KZ ZVAR
  13  13  13  4  4  4  2  2  2  15  15  15  10 10 10
  10  10 10  10  10  10 10 10 10  10 10  10 10  10 10 10
  10  10 10  10  10  10 10 10 10  10 10  10 10  10 10 10
  10  10 10  10  10  10 10 10 10  10 10  10 10  10 10 10
  10  10 10  10 10   10 10 10 10  10 10  10 10  10 10 10
  10  10 10  10 10  10 10  10 10

PVTEOS
   200

     CPT       PC           TC          MW         AC       ZCRIT     SHIFT

      CO2   1070.7000    547.5800    44.0100    .2250000    .274      -0.00089
      N2     491.6800    227.2900    28.0200   .0400000    .290      -0.16453
      C1     670.1000    335.9000    16.0400    .0130000    .288      -0.17817
      C2     707.7900    549.5900    30.0700    .0980000    .285      -0.06456
      C3     616.4100    665.7300    44.1000    .1520000    .281      -0.06439
      C4-6   498.2000    713.2000    67.2800    .2340000    .272      -0.18129
      C7P1   376.2000   1030.5000   110.9000    .3320000   .264        0.12080
      C7P2   245.4000   1134.4000   170.9000    .4950000   .251        0.23442
      C7P3   124.9000   1552.7000   282.1000    .8330000   .224        0.54479

BIN
     -.02000   .10000   .13000   .13500   .12770   .10000   .10000   .10000
               .03600   .05000   .08000   .10020   .10000   .10000   .10000
                        .00000   .00000   .09281   .00000   .00000   .13920
                                 .00000   .00000   .00385   .00630   .00600
                                          .00000   .00385   .00630   .00600
                                                   .00000   .00000   .00000
                                                            .00000   .00000
                                                                     .00000
INITIAL
C  depth psat    z1    z2    z3 ...
 DEPTH
   7500. 3550. .0121 .0194 .6599 .0869 .0591 .0967 .0472 .0153 .0034

 PINIT 3550
 ZINIT 7500
 HWC   7500

SEP 1 1 TABLE ! Separator with split factors C4-(gas) C5+ (oil)
0.0   0.0 0.0 0.0 0.0 0.0  0.465 1.0 1.0 1.0
1.0   0.0 0.0 0.0 0.0 0.0  0.465 1.0 1.0 1.0

ENDINIT

MAPSPRINT 1  P KRG KRO VISG VISO SO SW
```

```
MAPSFREQ 1

WELL
    I J K1 K2
  PROD
    1  1  1  12


WELLTYPE
PROD   MCF

BHP
PROD    1000

RATE
PROD   6200

LIMITWELL
PROD  0   0   0  100  0   0  100

TIME 5000 365
END
```