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Water Coning Study In One of The Iranian Gas Reservoirs, Factors Affecting and Problems

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Abstract: The coning phenomenon usually occurs in water and gas cap drive reservoirs. Water coning in Iranian hydrocarbon reservoirs is one of the most important problems that affects the cumulative production, operation costs and causes environmental problems. Before producing from a reservoir, the fluids are in equilibrium and their contact surfaces remain unchanged, but after starting production from the reservoir, when the viscous force overcome gravitational force in vertical direction, contact surfaces will displace and coning will occur. Therefore, the production rates will be controlled in a range that prevents entering water and gas to the production well. For this reason, investigation and modeling of this phenomenon is extremely necessary. In this study, the coning phenomenon, parameters affecting coning (i.e. distance from GWC, high flow rate, turbulences and skin factor) and problems due to coning (such as increase in pressure gradient in well, permeability reduction near wellbore region and increase in residual gas saturation) had been studied for one of the Iranian gas reservoirs. The simulation study shows that water coning has a huge effect on reservoir performance and cease many problems in reservoir, well bore and surface facilities.

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Keywords: water coning, critical rate, skin, GWC, gas reservoir.

1. Introduction

1.1 Water Production in Gas Reservoirs

Water production kills gas wells, leaving a significant amount of gas in the reservoir. One study of large sample gas wells revealed that the original reserves figures had to be reduced by 20% for water problems alone [1].

Gas demand in the US increased 16% during the last decade, but gas production increased only 4.5% during the same period [2]. The demand for natural gas is projected to increase at an average annual rate of 1.8% between 2001 and 2025 [3].

Water production is one of the two recurring problems of critical concern in the oil and gas industry [4]. Many gas reservoirs are water driven. Water supplies an extra mechanism to produce the gas reservoir, but it can create production problems in the wellbore. These water production problems are more critical in low productivity gas wells.

1.2. Concept of Water-Coning

A counteracting gravitational force, due to the difference between the hydrocarbon density and water density, causes the gas-water contact interface to remain stable.

At the time when the wells in gas reservoirs underlain by bottom-water aquifers are produced, water tends to move upwards towards the gas-producing perforations in the shape of a cone. As the production rate of gas is increased, the height of water cone also increases above the original gas-water-contact (GWC) eventually resulting in a water breakthrough. This breakthrough of water in gas producing perforations is termed as 'water-coning'. Water is drawn upwards into the gas-bearing zone as a result of viscous forces overcoming the gravity forces during gas production.

It has been proposed that gas should be produced at rates less than the critical rate in order to avoid the production of water [5]. As a result, gas production from a well is limited and dictated by the maximum critical flow rate.

'Critical rate' is defined as the production rate at which water-free gas is produced and no water breakthrough occurs in the gas zone. However, the problem with this approach is that in most cases gas production at critical rates becomes economically unfeasible; as a result, considering other options of economically recovering these hydrocarbons becomes a necessity. The concept and mechanism of water-coning is well known among the researchers; however, its control is very limited because of the fact that only three out of seven factors can be controlled[6]. Factors that affect water-coning include well spacing, ratio of vertical to horizontal permeability, production rate, well penetration, mobility ratio, ratio of gravity force to viscous force and zone thickness and the research effort should be focused on the optimum design of the controllable variables.

1.3. Techniques for Water Coning Control

Several research efforts have been directed at understanding the mechanism of water coning in vertical wells or water cresting in horizontal wells. These research efforts have led to the calculations of the critical rate to avoid water coning; the time to water breakthrough at production rates above the critical rates, and prediction of water cut behavior with time after water breakthrough. Unfortunately, the proffered critical rates are usually uneconomic for any practical purposes. For this reason various techniques have been proposed in the literature to counter the problem of excessive water production in reservoirs with bottom-water aquifers. These techniques include: making perforations as far above the initial gas-water contact (GWC) as possible, well completion through the entire depth of the reservoir for pressure drop reduction, plug back the present well and horizontal well drilling (Figure 1), down hole separators (Figure 2), creation of low or no-permeability zones around the wellbore by injecting cement, resins, gels or polymers (Figure 3) [8, 7, 9]. Another technique recently proposed to control water coning is known as the "Dual-Completion Technique" or "Down hole Water Sink Technology (DWS)". In this technique, a well is completed in hydrocarbon and water zones both separated by a packer for segregated and simultaneous production of hydrocarbon and water, hence, countering and minimizing the effects of water-coning [10].

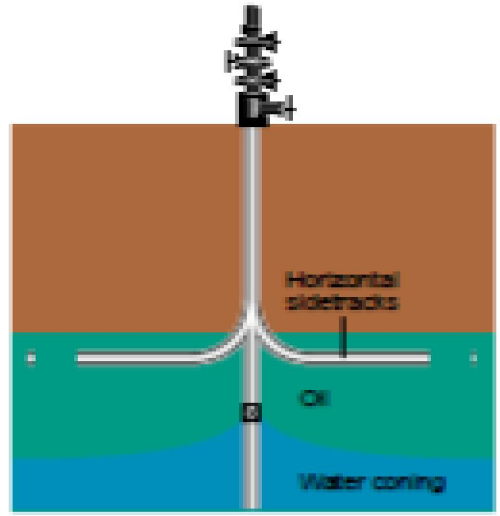

Figure 1: Lateral drain holes extend production in reservoirs affected by water coning [8].

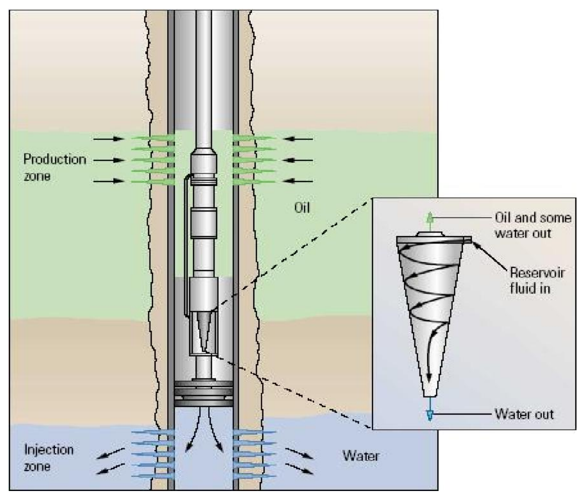

Figure 2: Down hole separator. Separating water down hole reduces the costs of lifting the excess water. Typical down hole separators are 50% efficient. The excess water is injected In to another formation [7].

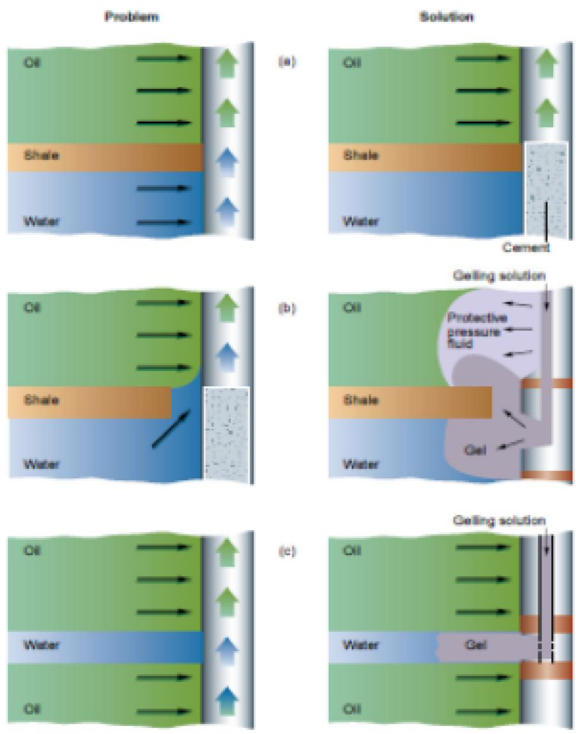

Figure 3: Cementing can be used within the wellbore to shut off aquifer layers (a), for more complex situations gels may be required to reduce water and increase oil production (b and c) [8].

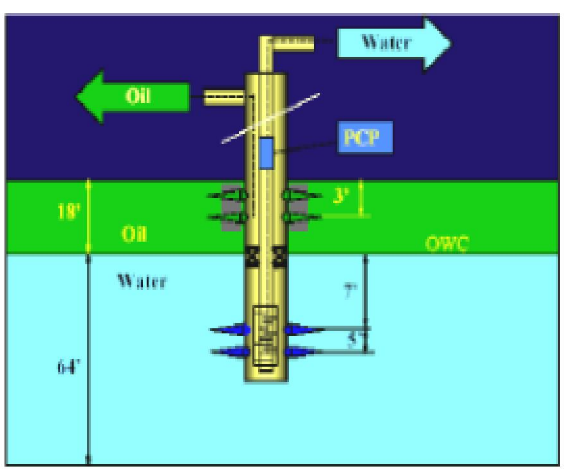

Figure 4: DWS technology for water coning control [10].

1.4. Critical Rate for Water Coning/ Cresting

Several correlations have been developed as a result of some research efforts to predict the critical rate to avoid water breakthrough, the time for water breakthrough and the post breakthrough behavior of the water influx at supercritical rates of production.

Critical rate is defined as the maximum rate at which oil/gas is produced without production of water [11]. The critical rate for oil-water systems has been discussed for several authors developing different correlations to calculate that rate. For gas-water system, however, no correlation has been published calculating critical rate, yet. One possible reason for the low interest in critical rate for gas-water system could be the general "feeling" that water coning in gas wells is less important than in oil wells.

Muskat (1982), for example, discussing about water coning problem said: "water coning will be much more readily suppressed and will involve less serious difficulties for wells producing from gas zones than for wells producing oil…the critical-pressure differential for water coning will be probably grater by a factor of at least four in gas wells than in oil wells."[12]. Joshi (1991) presets an excellent discussion about critical rate in oil wells. He included analytical and empirical correlation to calculate critical rate. The correlations include: Craft and Hawking method (1959), Meyer, and Garder method (1954), Chaperon method (1986), Schols method (1972), and Hoyland, Papatzacos and Skjaeveland method (1986). Joshi presents equations and example calculation for each method, concluding that the critical rate calculated for each method is different. He said that there is no right or wrong critical correlation, and each one should make decision about which correlation could be used for specific field applications. Meyer, and Garder correlation (1954), and Schols correlation (1972) are shown here as examples of critical rate equations for oil water system (Eqs. 2.1 and 2.2) [13, 14].

Meyer and Garder correlation (1954):

$$q_c = \frac{0.001535(\rho w-\rho o)k(H^2-D^2)}{\mu oBoln(\frac{re}{rw})} \quad (2.1)$$

Where: qc is critical oil rate (STB/D), $\rho w$is water density (gm/cc), $\rho o$is oil density (gm/cc), k is formation permeability (md), h is oil zone thickness (ft), D is completion interval thickness (ft), $\mu o$is oil viscosity (cp), Bo is oil formation volume factor (bbl/STB), re is external drainage radius (ft), and $rw$is wellbore radius (ft).

Schols correlation (1972):

$$q_c = \frac{(\rho w-\rho o)ko(H^2-Hp^2)}{2049\mu oBo} * \left[0.432 + \frac{\pi}{\ln(\frac{re}{rw})}\right]\left(\frac{h}{re}\right)^{0.14} \quad (2.2)$$

Where: $qo$is critical oil rate (STB/D), $\rho w$is water density (gm/cc), $\rho o$is oil density (gm/cc), $ko$is effective oil permeability (md), h is oil zone thickness (ft), $hp$is completion interval thickness (ft), $\mu o$is oil viscosity (cp), Bo is oil formation volume factor (bbl/STB), re is external drainage radius (ft), and $rw$is wellbore radius (ft).

Water coning supplies the liquid source for liquid loading in gas wells. Liquid loading begins when wells start producing gas flowing below the critical velocity in the wellbore. Different concepts and techniques have been used to solve water-loading problems in gas wells.

Trimble and DeRose (1976) discussed that Mustak-Wyckoff (1935) theory for critical rates in oil wells could be modified to calculate critical rate for gas wells. The procedure could give an approximate idea about the gas critical rate for quick field calculations. The modified Muskat-Wyckoff (1935) equation presented by Trimble and DeRose (1976) is [15, 16]:

$$qg = \frac{0.000703Kgh(Pe^2-Pw^2)}{ZTR\mu gln\left(\frac{re}{rw}\right)}\left[\frac{b}{h}\left(1+7\sqrt{\frac{rw}{2b}}cos\frac{\pi b}{2h}\right)\right](2.3)$$

Where: $qg$is gas flow rate (Mscf/d), kg is effective gas permeability (md), h is gas zone thickness (ft), $pe$is reservoir pressure at drainage radius (psia), pw is wellbore pressure at drainage radius (psia), $\mu g$is gas viscosity at reservoir conditions (cp), z is gas compressibility factor, TR is reservoir temperature (oR), re is external drainage radius (ft), $rw$is wellbore radius (ft), and b is footage perforated (ft).

Equations 2.3 and 2.4 are combined, and solved graphically following Muskat-Wyckoff (1935) procedure, calculating minimum drawdown preventing water coning [16].

$$\frac{\varphi w-\varphi D}{\varphi w-\varphi e} = 1-\frac{gh\Delta\rho}{\Delta p}\left(1-\frac{D}{h}\right)(2.4)$$

Where: $\varphi w$is potential at well radius (psi), $\varphi D$is potential at well radius and depth D (psi), $\varphi e$is potential at drainage radius (psi), $g\Delta\rho$ is difference in hydrostatic gradient at reservoir conditions between the gas and water (psi/ft), $\Delta p$is pressure drawdown (psia), h is gas zone thickness (ft), and D is distance from formation to cone surface at r (ft).

Trimble and DeRose (1976) procedure combined gas flow equation (Eq. 2.3) with oil graphical solution for Eq. 2.4. Changes in oil density and viscosity with respect to pressure are negligible. Gas properties (density, and viscosity), however, strongly depend on pressure; therefore, the previous procedure should be used as a reference with limitations.

2. Reservoir Description

The field under study is Sarkhoon gas field which is a reservoir that has dimensions of 75.27 Km * 5.7 Km. this field is at 20 Km north east of Bandar Abbas, which has two reservoirs including: Guri – Bazdeh and Jahrum – Razak. The first well in this field has been drilled in 1973. Production from this field has been started at 1987. Gas and condensate daily production potential of this field are 14.15 MMm^3 and 12990 STB, respectively. Initial gas in place of this reservoir is 318.42 MMMm^3 and its recoverable gas volume is 267.156 MMMm^3. This field has initial temperature of 211° F and initial pressure of 5350 psia. The depth of the top of the reservoir is about 9022 ft. subsea. gas oil contact is at 10482 ft subsea. Mean reservoir thickness is 1460 ft. Figure 5 shows a schematic of this field.

2.1. Simulation Model Description

For better consideration of near wellbore coning study; the simulation model consists of a 12000 ft radius cylindrical sector of this reservoir with a well in the center of the model. This sector has 14 layers in gas zone and a huge aquifer under it.. The average vertical to horizontal permeability ratio is 0.1. Reservoir permeability is equal to 30md. Aquifer permeability is equal to 1 md.

Average porosity of reservoir and aquifer is 9%. Total pore volume of this sector in gas zone is 17MMMcu.ft. Average oil, water and gas saturations are 0.0, 0.29, 0.71 respectively; thus reservoir volume of each phase is 0.0, 12.13, 4.87 MMMcu.ft respectively.

Permeability distribution of this cylindrical model are shown in Figure 6.

2.2. Reservoir Rock and Fluid Interaction Properties

The relative permeability data are shown in Figures 7 and 8 respectively.

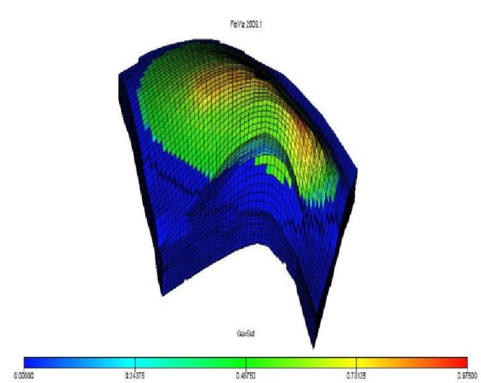

Figure 5: A schematic of Sarkhoon gas field.

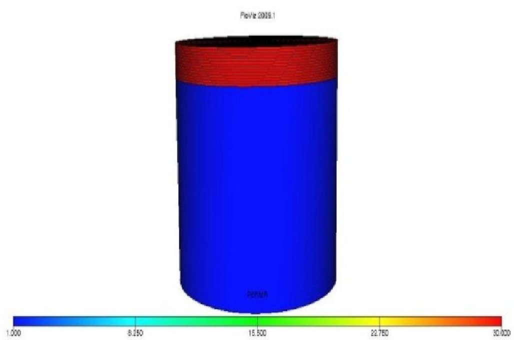

Figure 6: Permeability distribution of the model.

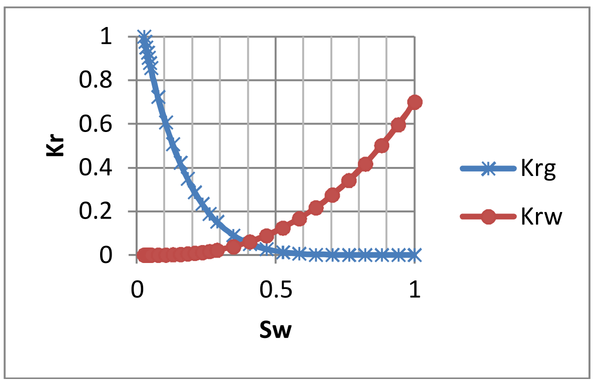

Figure 7: Water - gas relative permeability data v.s water saturation.

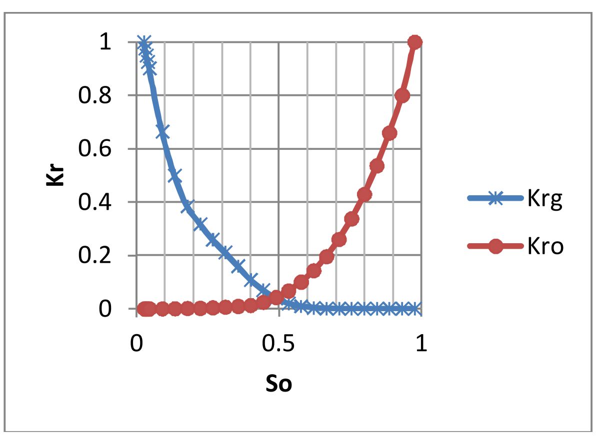

Figure 8: Oil – gas relative permeability data v.s oil saturation.

2.3. PVT Analysis of the Reservoir Fluid

PVT data were obtained from the gas sample of well number 8 of this reservoir. This sample was taken from GURI-PAY formation, Sarkhoon field at depth of 10062-10482 ft. This single PVT data is applicable to all regions of this model. Average GOR of this model is 67 (MSCF/STB). For tuning a suitable EOS for this sample the PVTi software was used. After doing several modifications in this part, 3- parameter Peng Robison equation of state and modified Lorentz-Bray-Clark for tuning of viscosity equation was chosen. After lots of efforts including: splitting the C7+, lumping and reducing the components to only seven and selecting proper regression parameters, an excellent match for the mentioned EOS and viscosity equation was obtained. The final regressed data are then exported to the simulation model in PROPS Section. The input composition of the reservoir fluid for simulation runs is also shown in Table 1. This reduction of components was practical for saving time and money in simulation runs.

Table 1: Input composition of the reservoir fluid for simulation runs.

Component	Mole fraction	MW
N2	0.0467680	28.013
CO2	0.0034901	44.01
C1	0.8667530	16.043
GR1	0.0591630	37.48424013
GR2	0.0062823	75.91258103
GR3	0.0078778	106.0506329
GR4	0.0096659	139.6448594

3. Factors affecting water coning

In this part different factors which affect water coning in a single vertical well would be studied. It should be noted that factors that had been introduced here, are those which affect water coning in vertical well drilled in a specified gas reservoir. These factors affects should be considered through all periods of reservoir development includes: before drilling, while drilling and production. These factors are summarized as below:

- Distance from gas water contact
- Rate effect
- Turbulence effect
- Skin effect

3. 1. Distance from gas water contact (GWC)

In order to investigate the effect of distance from gas water contact (GWC); four completion intervals as completion in layers 1 to 4 (DISTANCE_FROM_GWC_1-4), 5-8 (DISTANCE_FROM_GWC_5-8), 9-12 (DISTANCE_FROM_GWC_9-12) and 11-14 (DISTANCE_FROM_GWC_11-14) with a constant gas production rate of 40MMSCFD were tested. It should be noted that for eliminating the turbulence effect on results, completion interval held constant in all cases.

As it shown in Figure 9, the distance from GWC has no effect on total produced gas, which is because of constant gas production rate selected.

As it can be found from Figures 10 and 11 with decreasing the completion distance from GWC water cut and total water production increased.

Figures 12 and 13 shows the effect of water cut on field pressure and well bottom hole pressure respectively. It is obvious that with increasing water cut, field pressure and well bottom hole pressure decreases. This reduction in pressure as water cut increases is because of permeability reduction near the well bore and pressure gradient increase in the well bore due to water flow to the well.

As it can be seen from Figure 13 at early times bottom hole pressure in 5-8 completion is higher than 1-4 completion which is due to symmetric position of 5-8 completion case with respect the reservoir thickness. When 5-8 completion case starts a little water production, pressure dropped rapidly just because of water cut increase.

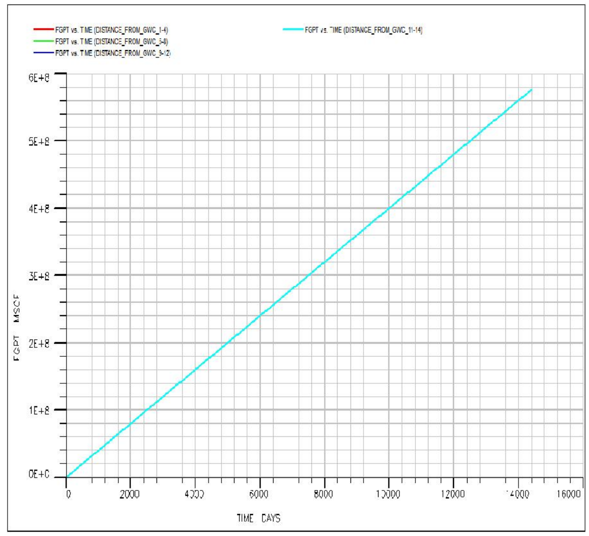

Figure 9: Field total gas produced v.s time for different distances from GWC.

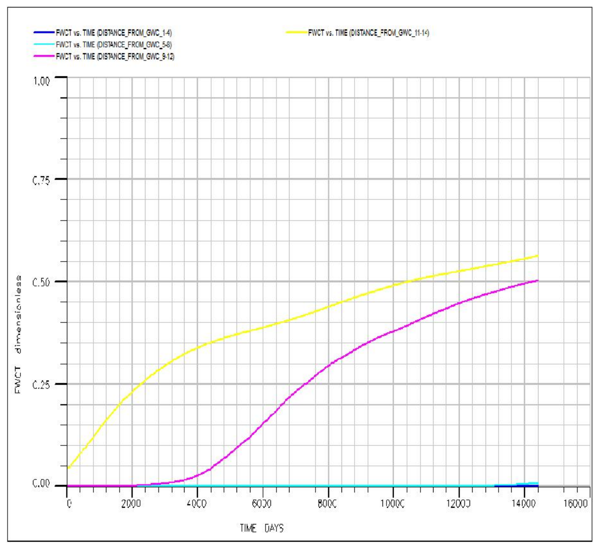

Figure 10: Field water cut v.s time for different distances from GWC.

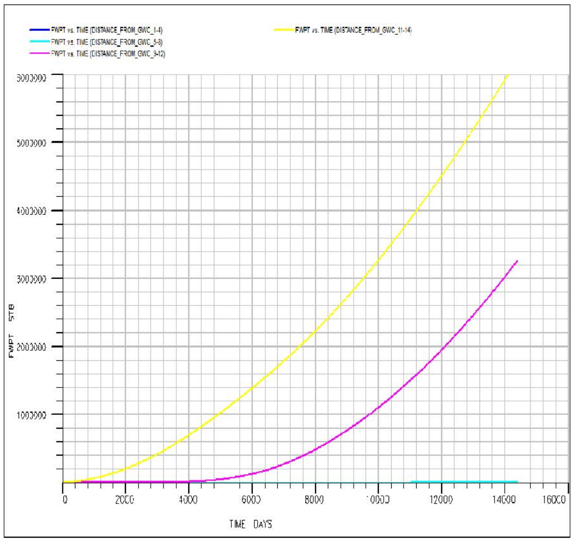

Figure 11: Field total water produced v.s time for different distances from GWC.

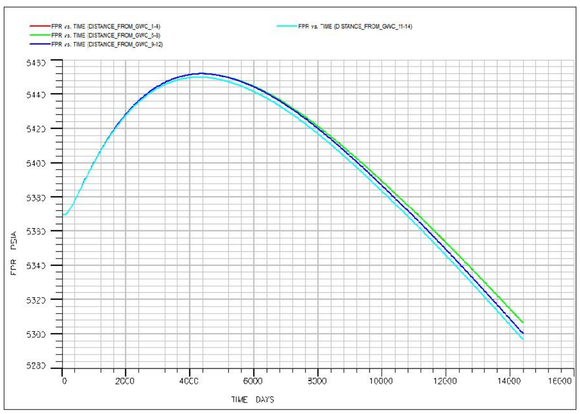

Figure 12: Field pressure v.s time for different distances from GWC.

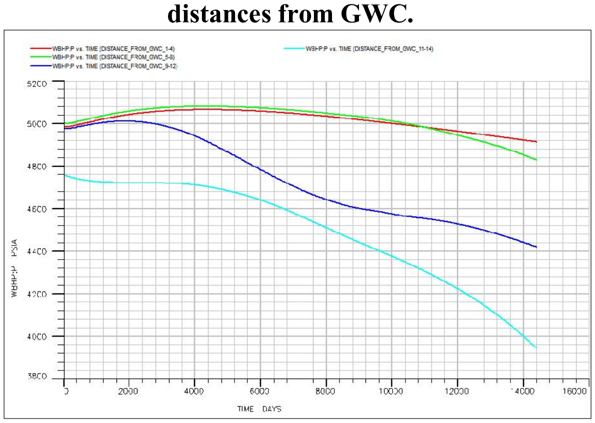

Figure 13: Well bottom hole pressure v.s time for different distances from GWC.

3.2. Rate effect

In order to investigate the rate effect on total produced gas, water cut and total produced water, four rates includes 20MMSCFD (RATE_EFFECT_1-12_RATE20000), 30MMSCFD (RATE_EFFECT_1-12_RATE30000), 40MMSCFD (RATE_EFFECT_1-12_RATE40000) and 50MMSCFD (RATE_EFFECT_1-12_RATE50000) all completed in layers 1-12, were tested.

As it shown in Figure 14 with increasing gas production rate, total produced gas increased. Also from Figures 15 and 16 it is evident that with increasing gas production rate water cut and total produced water increased, which confirm this fact that water coning is a rate sensitive phenomenon.

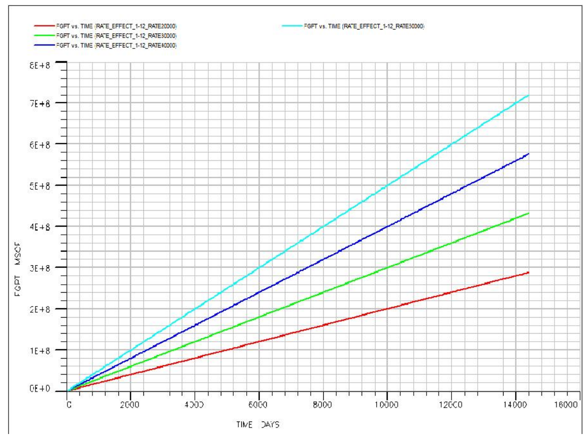

Figure 14: Field total gas produced v.s time for different gas production rates.

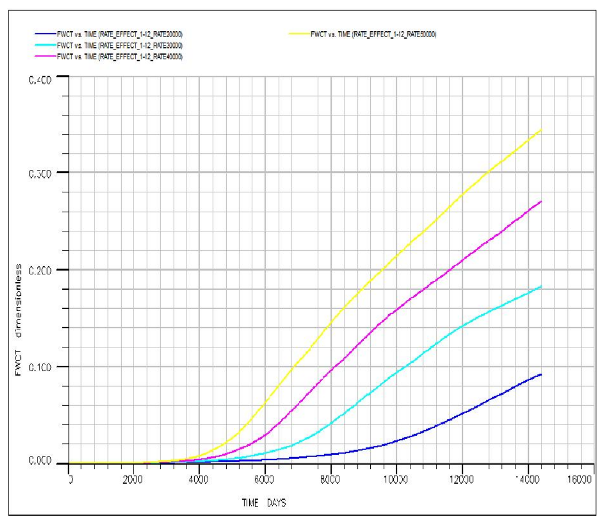

Figure 15: Field water cut v.s time for different gas production rates.

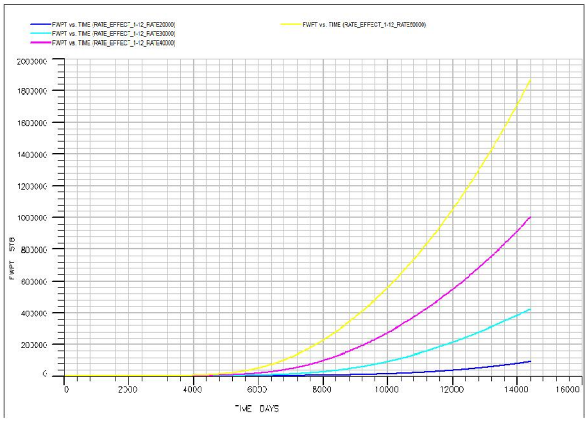

Figure 16: Field total water produced v.s time for different gas production rates.

3.3. Turbulence effect

In this part the effect of perforation interval length would be investigated with testing four completion intervals as completion in layers 1 to 12 (PERFORATION_INTERVAL_1-12), 4-12 (PERFORATION_INTERVAL_4-12), 8-12 (PERFORATION_INTERVAL_8-12) and 10-12 (PERFORATION_INTERVAL_10-12). Gas production rate is constant and equal to 40MMSCFD in all cases. It should be noted that for eliminating the effect of distance from GWC lower limit for completion held constant in layer 12 for all cases.

As it can be found from Figures 17 and 18 with decreasing the completion interval length water cut and total water production increased; which is because of pressure gradient increased due to turbulence effects.

Figures 19 and 20 shows the effect of water cut on field pressure and well bottom hole pressure respectively. It is obvious that with increasing water cut, field pressure and well bottom hole pressure decreases. This reduction in pressure as water cut increases is because of permeability reduction near the well bore and pressure gradient increase in the well bore due to water flow to the well.

3.4. Skin effect

In this part the effect of skin factor on water cut and total water produced would be investigated. Skin values for this investigation include 0 (SKIN_EFFECT_0), 2 (SKIN_EFFECT_2) and -2 (SKIN_EFFECT_-2). Gas production rate is constant and equal to 40MMSCFD in all cases. It should be noted that for eliminating the effect of other parameters, the completion interval is 1 to 8 for all cases.

As it is evident from Figures 21 and 22 changing the skin factor has no effect on water cut and total water produced.

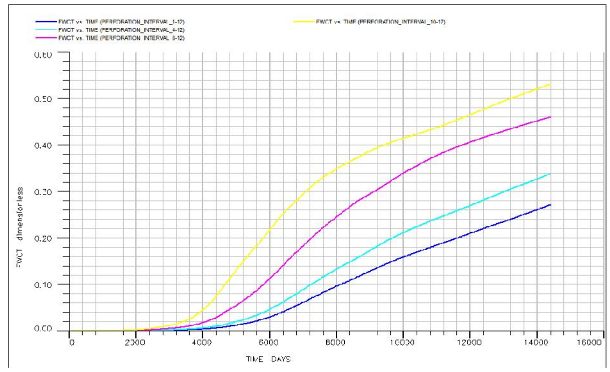

Figure 17: Field water cut v.s time for different completion intervals.

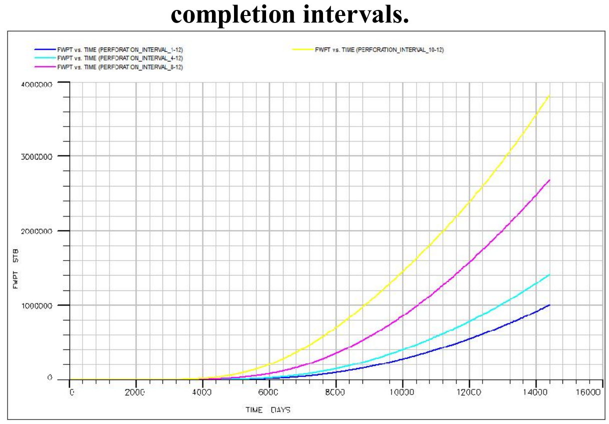

Figure 18: Field total water produced v.s time for different completion intervals.

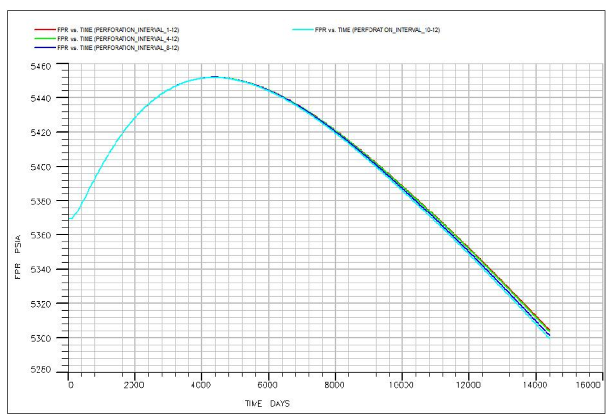

Figure 19: Field pressure v.s time for different completion intervals.

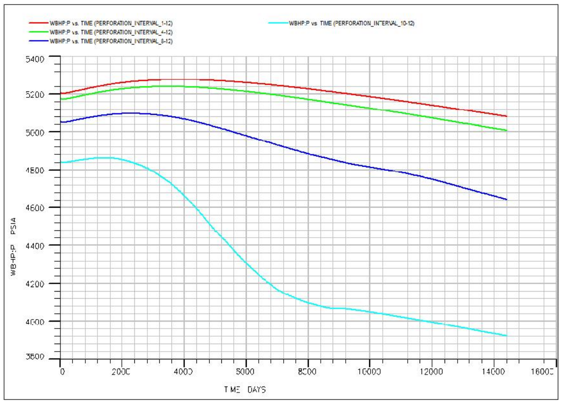

Figure 20: Well bottom hole pressure v.s time for different completion intervals.

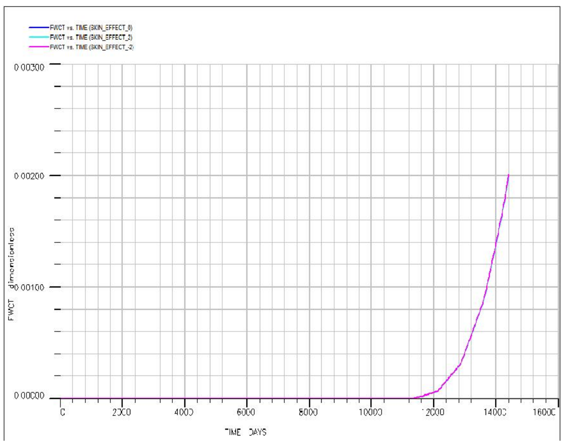

Figure 21: Field water cut v.s time for different skin factors.

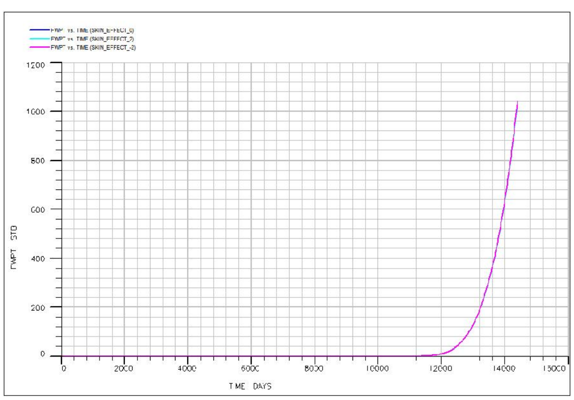

Figure 22: Field total water produced v.s time for different skin factors.

4. Problems due to coning

Water production from gas wells leads in some problems. In this part these problems are classified and illustrated in brief. These problems are classified as below:

- Reservoir and well bore related problems
- Surface facility related problems
- Environmental related problems

4.1. Reservoir and well bore related problems

The problems related to reservoir and well bore includes: permeability reduction near well bore, increase in residual gas saturation near well bore region and increase in pressure gradient in well bore. These three problems which are related to reservoir and well bore are explained briefly as below:

- Permeability reduction near well bore region

As water cone starts its flow to the well bore, its saturation near the well bore increase and cease in permeability near well bore region.

- Pressure gradient increase in wellbore

As a result of water flow in the well, pressure gradient of well bore fluid increase and cease in more pressure drop in the well bore, thus for maintain the production rate at a constant value; the bottom hole pressure of the reservoir dropped more over than the case of no water inflow to well.

- Residual gas saturation increase near well bore region

Water flow to the well bore cease increase in water saturation near well bore region. This increase in water saturation near well bore region trapped the gas phase in regions near well bore and increases the residual gas saturation near the well bore. This trapped gas is unmovable and could not be produced.

4.1.1. Permeability reduction and increase in well bore pressure gradient

Figure 23 shows the bottom hole pressure v.s water cut for completion intervals of 1-4, 2-5, 3-6, 4-7, 5-8, 6-9, 7-10, 8-11, 9-12, 10-13, 11-14. Gas production rate is constant and equal to 40MMSCFD for all cases. It is obvious that, as gas production rate maintain constant the pressure reduction due to different rates eliminates. As completion intervals goes to the bottom of the reservoir the pressure should increase because of vertical pressure gradient in the reservoir, but as it can be seen from Figure 23 the bottom hole pressure reduced, which is just because of increase in water cut.

This bottom hole pressure reduction is due to increase in pressure gradient in the well bore and reduction in near well bore permeability ceased by water flow to the well.

4.1.2. Residual gas saturation increase in near well bore region

Figure 24 shows the water saturation change in one of this sector blocks of this reservoir sector. Completion interval is 9-12 and gas production rate is 20MMSCFD. It is obvious that after reaching water saturation to 0.76 the water saturation don't increase (i.e no reduction occurs in gas saturation). A gas saturation of 0.24 remains unmovable in pore spaces and could not be produced.

For all grid blocks which invaded by water, residual gas saturation which trapped by water is equal to 0.24. This residual gas saturation trapped a considerable gas volume in the reservoir which could not be produced.

4.2. Surface facility and environmental related problems

Rather than reservoir and well bore related problems, water production had surface facility and environmental related problems. When water produces to surface, surface facilities such as desalination units and disposal constructions are needed, which increases the operational costs.

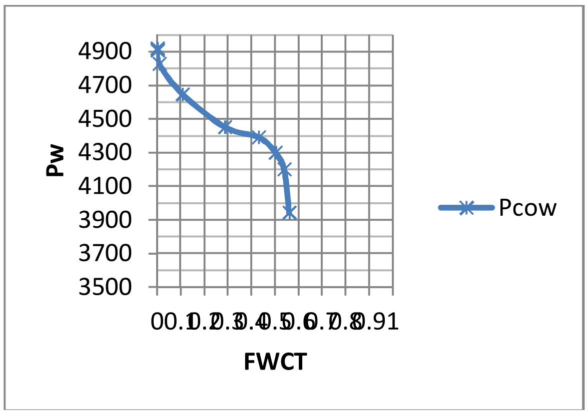

Figure 23: Well bottom hole pressure v.s Field water cut.

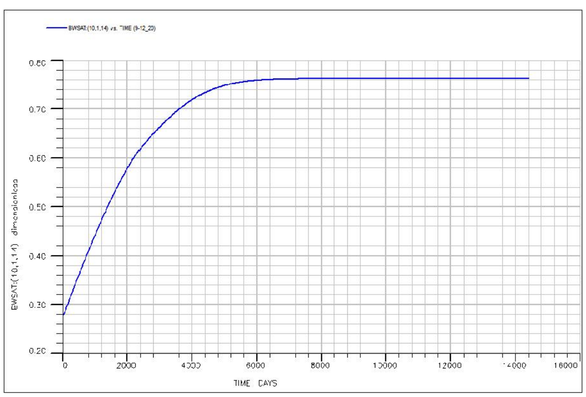

Figure 24: Block water saturation v.s time.

Conclusions

1. The simulation study has proved that as distance from GWC decreases, water cut increases.
2. According to simulation runs, increase in gas production rate results in near wellbore pressure gradient increase and as a result water cut increases in well bore.
3. As perforation interval decreases, the pressure gradient near the well bore increases and results in water cut increase.
4. Skin factor has no effect on water cut and total produced water.
5. Water coning and its production to the well bore results in gas relative permeability reduction near well bore region, pressure gradient increase in well bore and residual gas saturation increase near well bore region.

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