Water Coning Study In One of the Iranian Gas Reservoirs, Problems and Remedial Techniques

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Abstract:

The water coning phenomenon usually occurs in water 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 to the production well. For this reason, investigation and modeling of this phenomenon is extremely necessary. In this study, the coning phenomenon, controlling methods (i.e. below critical rate production, plug in and DWS technology) 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 the best choice for water coning controlling method in gas reservoirs, at rates above critical is strong function of allowable water production rate in DWS technology; but a more simple and efficient method in these cases is plug in.

Key words: water coning, critical rate, plug in, DWS, gas reservoir.

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1-Introduction

In 1998, produced water from 40 counties in the state of Colorado was estimated as 220.6 million barrels in comparison to only about 22.46 million barrel of oil produced over the same period, while 2001 production stood at 360 million barrels of water against 25.5 million barrels of crude oil [1].

In 1993, the U.S. produced about 2.5 billion barrels of crude oil as against about 25 billion barrels of associated unwanted water for the same year [2]. Similar problem of produced waters exists in the North Sea and in the Niger Delta Basin, as well as in the Middle East. The extent to which produced water problem is a big nuisance in the oil and gas industry is reflected in the fact that unwanted production of water has been estimated to cost the petroleum industry about $45 billion a year [3].

These costs according to Halliburton include the expense to lift, dispose or re-inject produced waters, as well as the capital investment in surface facility construction and to address other environmental concerns. In fact Kimbrell (2001) asserted that, “Produced water is a fact of life in Louisiana. The largest volume of waste associated with oil and gas production operations in Louisiana, as well as nationally, is produced water. The amounts of produced water are overwhelming compared to the amounts of hydrocarbons produced. In 1993, over 1.2 billion barrels of produced water was generated compared to less than 200 million barrels

of oil and condensate and a little over 200 million BOE (barrel oil equivalent) of gas produced in the same period. From 1990 to 1993, the statewide water-hydrocarbon ratio (WHR) averaged approximately 3.2 [4].

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 [5].

Gas demand in the US increased 16% during the last decade, but gas production increased only 4.5% during the same period [6]. The demand for natural gas is projected to increase at an average annual rate of 1.8% between 2001 and 2025 [7].

Water production is one of the two recurring problems of critical concern in the oil and gas industry [8]. 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 [9]. 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 [10]. 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- Problem Definition and Research Objectives

In the past, water coning in gas wells has not received much attention from researcher in the petroleum industry. The reason for that probably is the general “feeling” that the problem is of minimal importance or even does not exist because of the high gas mobility compared with the water mobility. Therefore, few studies have been done addressing reservoir mechanisms increasing water coning/production in gas reservoir. The low gas price experienced during the last decade reduced the interest in gas well problems at the United States. This low gas price environment, however, has slowly changed since the beginning of this century due to increases in gas demand and reduction in gas supply, pushing people trying to explain, understand and solve gas production/recovery problems.

In view of these issues and problems, a simulation study was conducted in order to study the phenomenon of water-coning in field-scale gas reservoirs.

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 1 shows a schematic of this field.

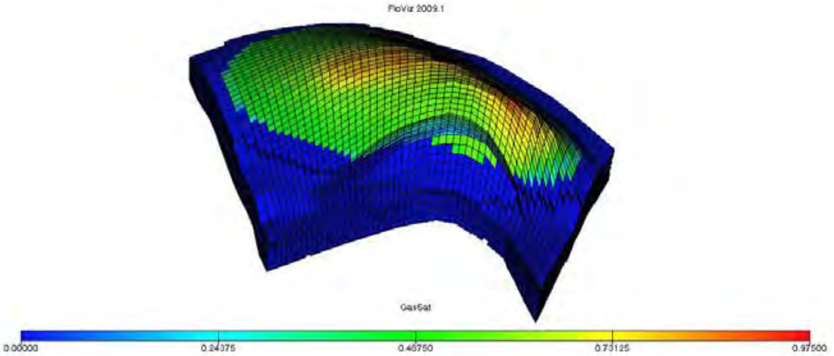

Figure 1: A schematic of Sarkhoon gas field.

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.

Initial saturation distribution of this cylindrical model is shown in Figure 2.

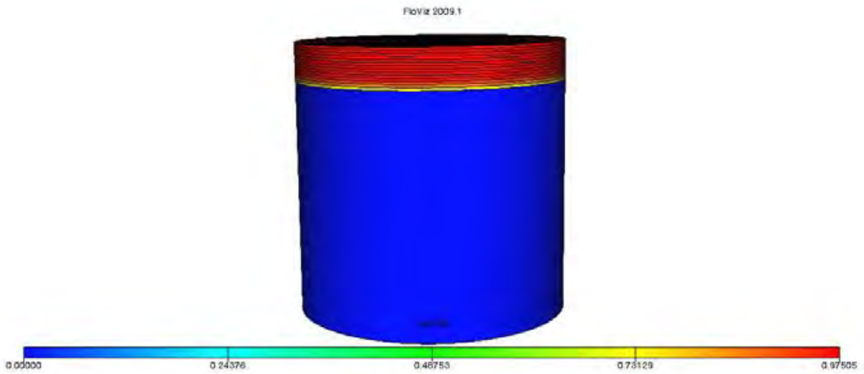

Figure 2: Initial saturation distribution of the model.

2-2- 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- Controlling methods

In this section three main water coning controlling methods would be studied, compared and the best controlling method would be selected. Controlling methods which had been tested in this section are summarized as below:

- Plug in the well bore bottom
- Production below critical rate
- DWS technology

3-1- Plug in the well bore bottom

In this part for water production control and reduction of water cut, well bore bottom would be plugged by cement. In order to see the effect of plugged bottom on water cut and total produced water two cases include completion from layer 1 to 8 and completion from layer 1 to 12 were tested. Gas production rate is constant and equal to 40MMSCFD in all cases.

In the following figures the legends: (NORMAL_1-8), (PLUG_1-8), (NORMAL_1-12) and (PLUG_1-12) accounts for completion from layer 1 to 8 without plug, completion from layer 1 to 8 with plug, completion from layer 1 to 12 without plug and completion from layer 1 to 12 with plug respectively.

As it is evident from Figures 3 and 4 with plug in the well bore bottom in the case of 1-8 completion water cut and total produced water reduced to zero and from Figures 5 and 6 for 1-12 completion water cut and total produced water reduced but not to zero, which shows the effect of distance to GWC on plug in controlling method.

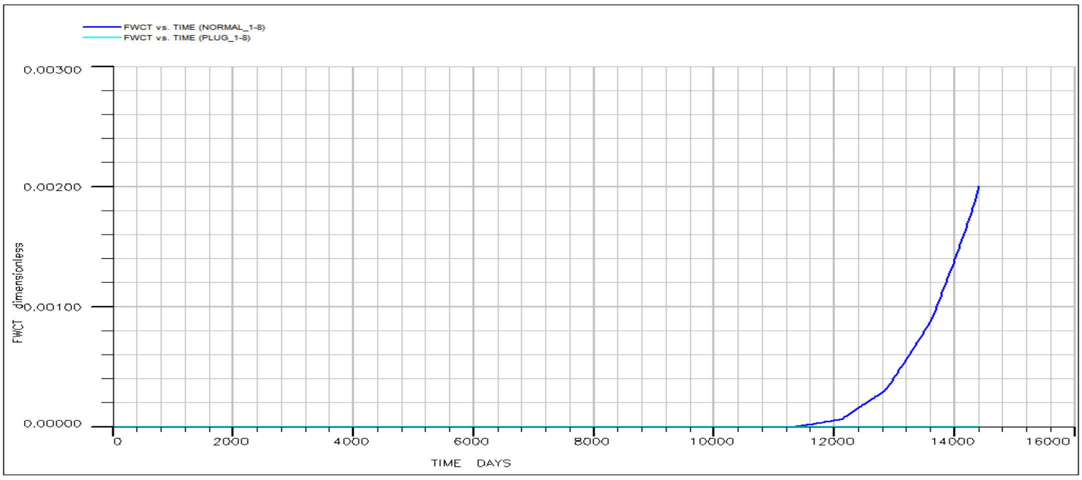

Figure 3 : Effect of plug in controlling method on field water cut for completion interval of 1-8.

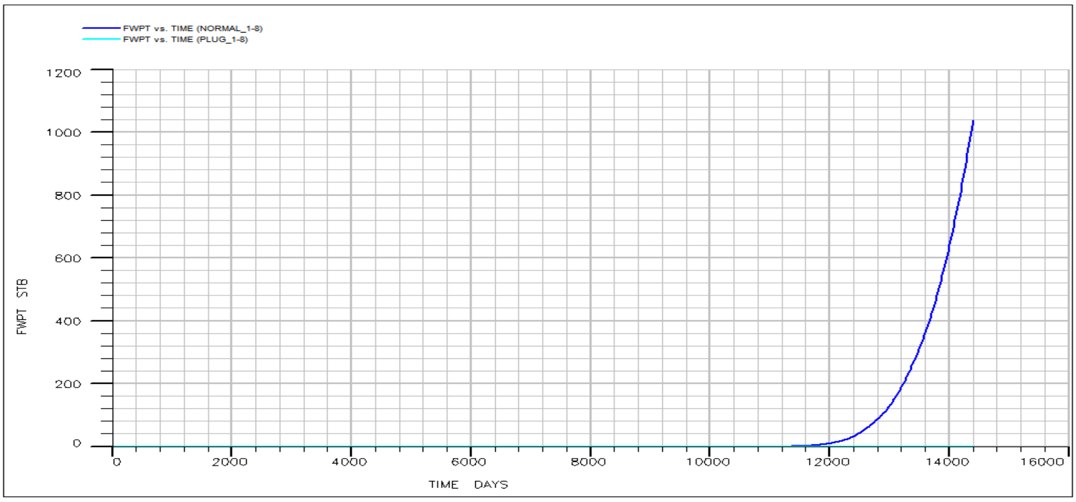

Figure 4: Effect of plug in controlling method on field total water produced for completion interval of 1-8.

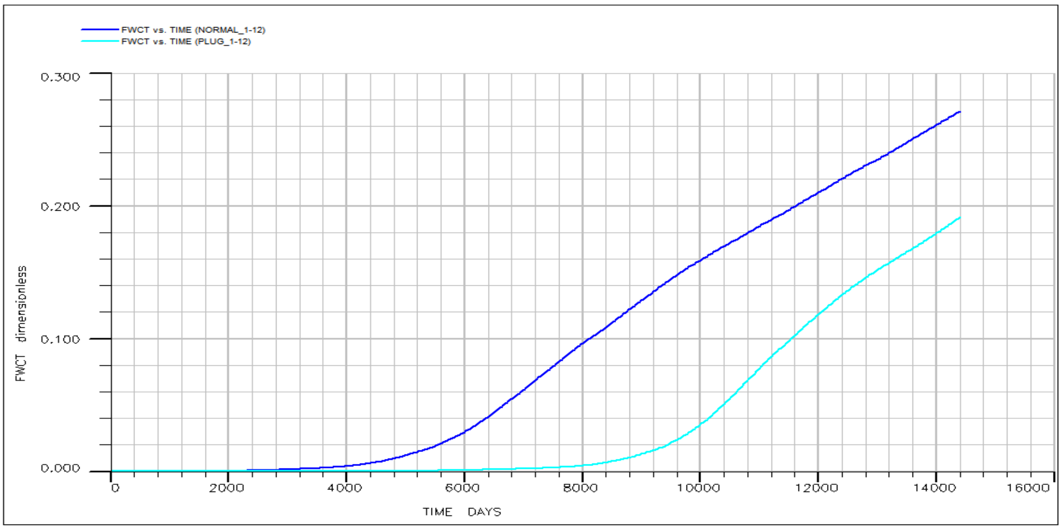

Figure 5: Effect of plug in controlling method on field water cut for completion interval of 1-12.

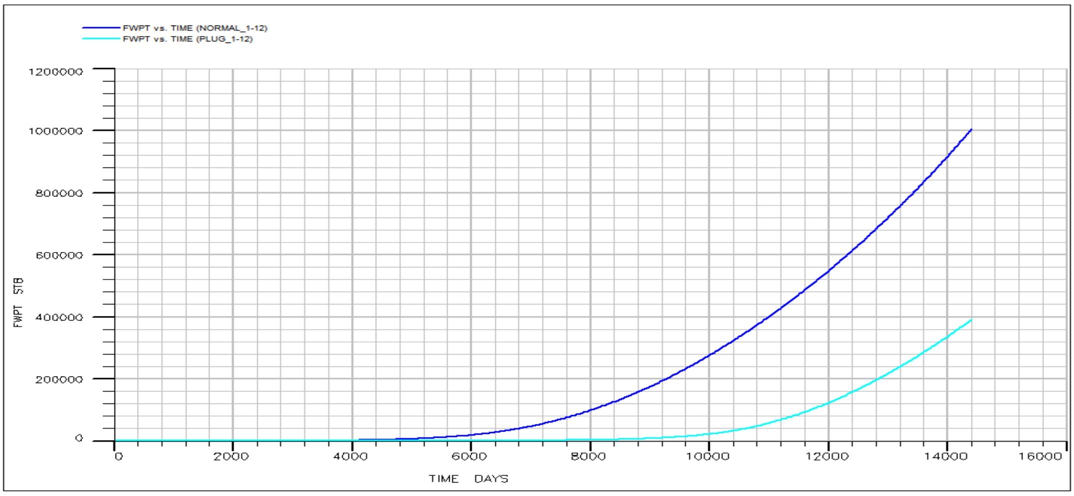

Figure 6: Effect of plug in controlling method on field total produced water for completion interval of 1-12.

3-2- Production below critical rate

In this controlling method, two completion intervals include 1-4 and 1-8 had been tested with two rates; one rate below critical and the other above critical. For completion interval of 1-4 gas produced with a rate of 50MMSCFD for below critical case, and rate of 80MMSCFD for above critical rate. In the case of 1-8 completion intervals, rates of 20MMSCFD and 60MMSCFD were tested for production under critical rate and above critical rate respectively. It should be noted that the critical rate for 1-4 and 1-8 completion cases are 60MMSCFD and 30MMSCFD respectively, which shows the effect of distance from GWC on critical rate.

In the following figures the legends: (BELOW_CRITICAL_1-4), (ABOVE_CRITICAL_1-4), (BELOW_CRITICAL_1-8) and (ABOVE_CRITICAL_1-8) accounts for production below critical rate from layers 1 to 4, production above critical rate from layers 1 to 4, production below critical rate from layers 1 to 8 and production above critical rate from layers 1 to 8 respectively.

Figures 7 and 8 shows the effect of below and above critical rate production on water cut and total produced water for completed layers from 1-4. It is obvious that production below critical rate reduces water cut to zero.

Figures 9 and 10 also show these effects for 1-8 completion case.

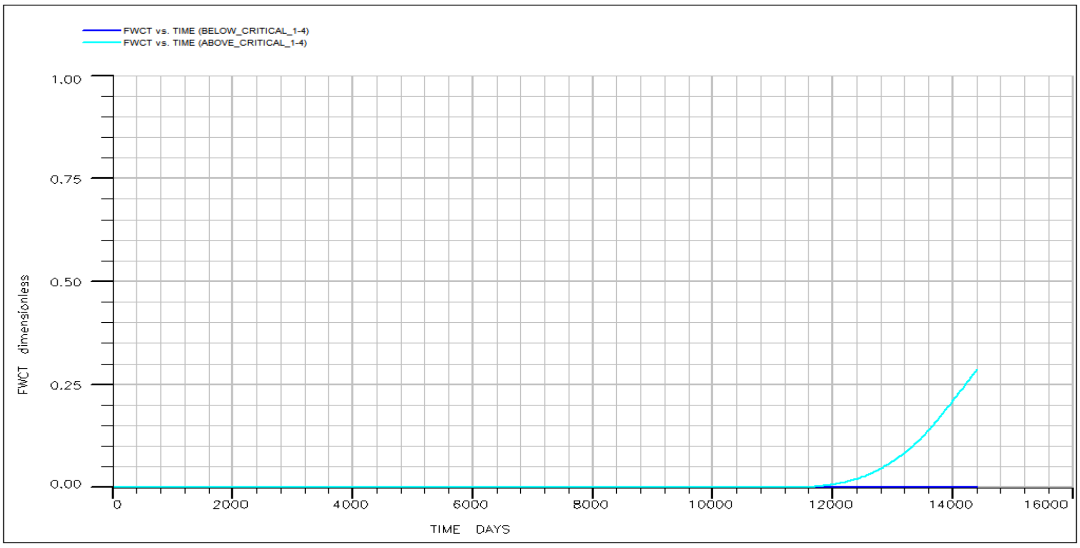

Figure 7: Effect of critical rate controlling method on field water cut for completion interval of 1-4.

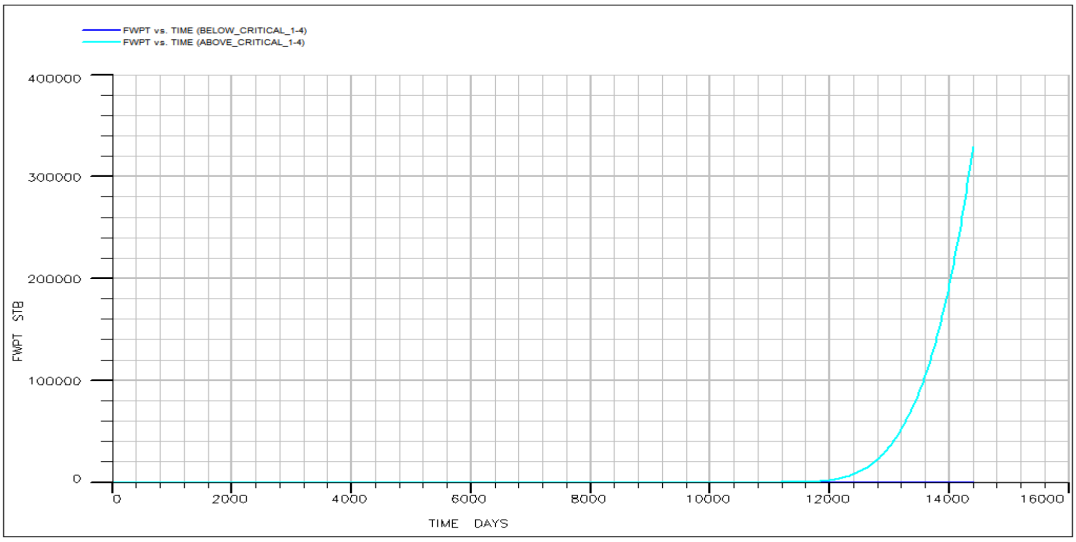

Figure 8: Effect of critical rate controlling method on field total produced water for completion interval of 1-4.

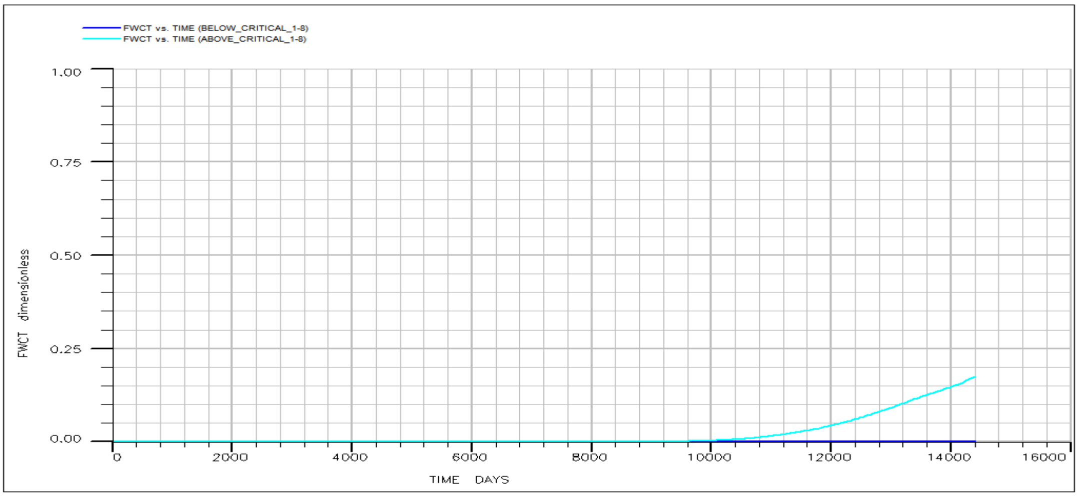

Figure 9: Effect of critical rate controlling method on field water cut for completion interval of 1-8.

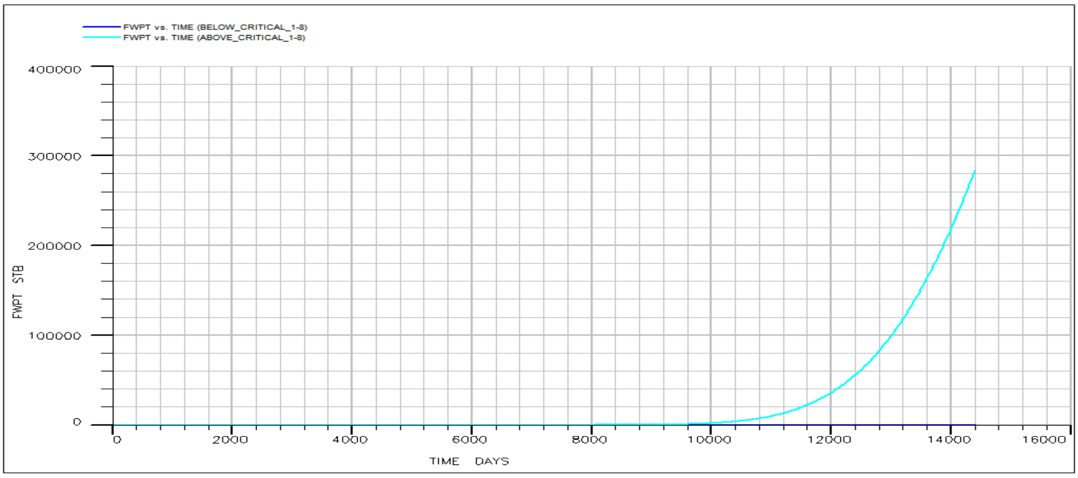

Figure 10: Effect of critical rate controlling method on field total produced water for completion interval of 1-8.

3-3- DWS technology

In this part DWS technology controlling method had been studied and the effect of allowable water production rate on performance of this method had been considered.

In the following figures production without DWS technology, production with DWS and allowable water production rates of 1000, 2000 and 4000 STBD had been compared for two completion intervals of 1-8 and 1-12.

In this technology water produces to the surface without affects such as increase in pressure gradient in the well bore, reduction in effective permeability near well bore region and residual gas saturation increase due to water inflow to the well, but surface problems such as environmental problems and surface facility problems still stay a conflict to be solved.

In the following figures the legends: (NORMAL_1-8), (DWS_1-8_RATE1000), (DWS_1-8_RATE2000), (DWS_1-8_RATE4000), (NORMAL_1-12), (DWS_1-12_RATE1000), (DWS_1-12_RATE2000) and (DWS_1-12_RATE4000) accounts for production without DWS in layers 1-8, production with DWS in layers 1-8 and allowable water production rate of 1000 STBD, production with DWS in layers 1-8 and allowable water production rate of 2000 STBD, production with DWS in layers 1-8 and allowable water production rate of 4000 STBD, production without DWS in layers 1-12, production with DWS in layers 1-12 and allowable water production rate of 1000 STBD, production with DWS in layers 1-12 and allowable water production rate of 2000 STBD, production with DWS in layers 1-12 and allowable water production rate of 4000 STBD respectively.

Figures 11 to 14 show this controlling method effect on water cut and total produced water with three different allowable water production rates in two completion cases of 1-8 and 1-12. It is obvious that this technology reduces water cut and total produced water in gas producing well. In this technology as allowable water production rate increases, water cut and total water produced in gas production well decreases, which shows that this technology is a strong function of allowable water production rate.

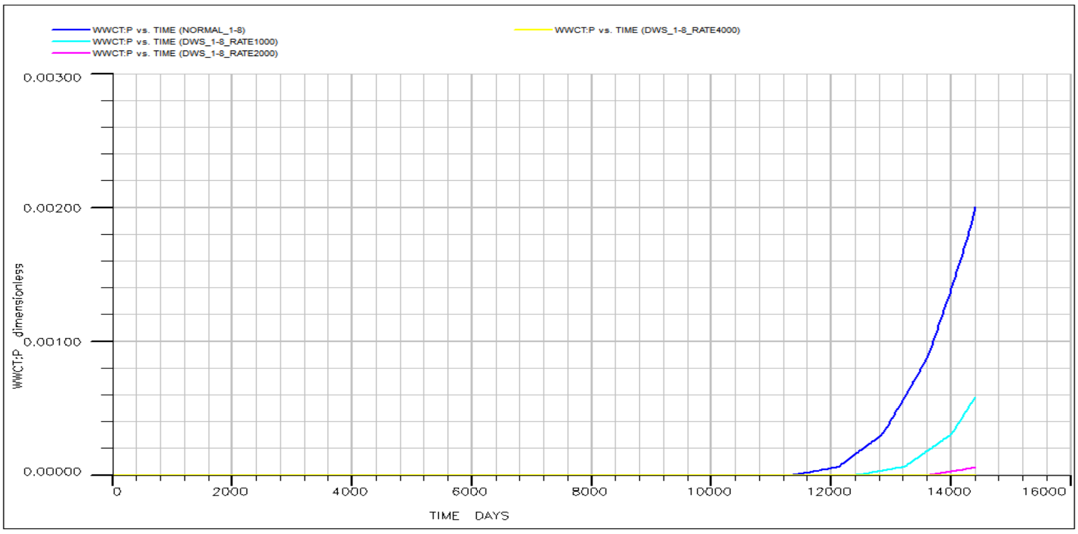

Figure 11: Effect of DWS technology controlling method on well water cut for completion interval of 1-8.

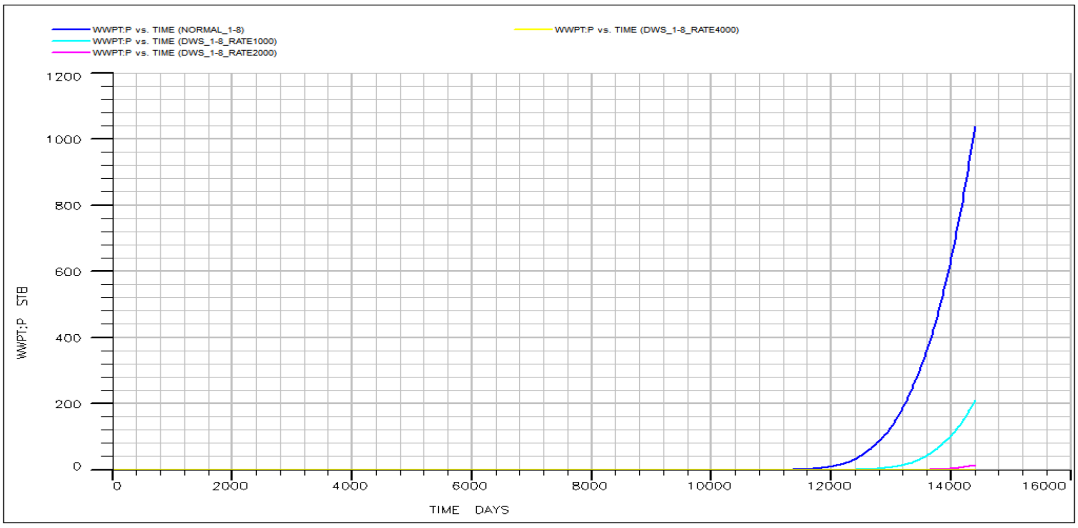

Figure 12: Effect of DWS technology controlling method on well total produced water for completion interval of 1-8.

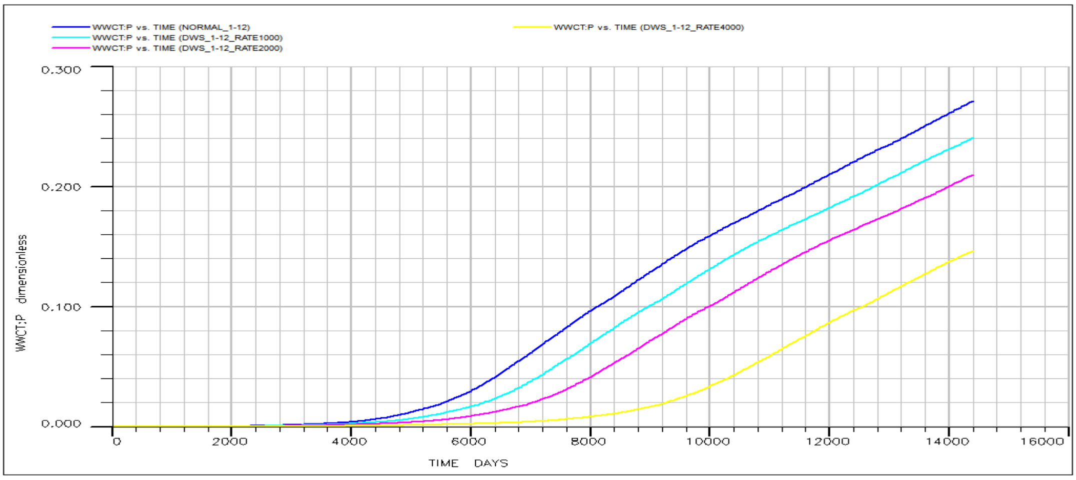

Figure 13: Effect of DWS technology controlling method on well water cut for completion interval of 1-12.

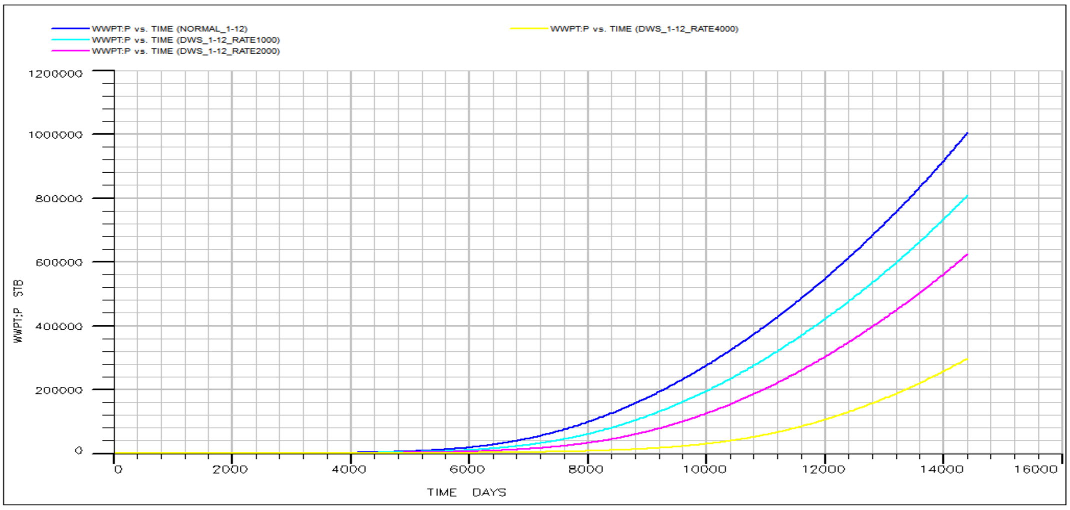

Figure 14: Effect of DWS technology controlling method on well total produced water for completion interval of 1-12.

3-4- Controlling methods comparison

In this section three main controlling methods includes: production below critical rate, plug in and DWS technology had been compared and tabulated in Table 2.

In Table 2 four different controlling methods includes: plug in, DWS technology with an allowable water production rate of 1000STBD (DWS1000), DWS technology with an allowable water production rate of 2000STBD (DWS2000) and DWS technology with an allowable water production rate of 4000STBD (DWS4000) are compared with each other and normal production without any controlling method (Normal) for layers completed intervals illustrated in column 1 of Table 2.

Gas production below critical rate is the best choice, but in some cases because of economical and demand reasons the gas production rate should be increased to a value which is higher than critical rate. In such cases comparison between these controlling methods is necessary.

DWS technology is a strong function of allowable water production rate, which as water production rate increases, the water cut in gas well decreases.

The comparison parameter is breakthrough time; the greater breakthrough time, the better the controlling method.

Comparison between plug and DWS depend on allowable water production rate for DWS technology.

Table 2: Controlling methods comparison

Layer completion	Critical rate MSCFD	Rate tested MSCFD	Controlling method	Breakthrough time(day)
1-4	60000	80000	Normal	12120
1-4	60000	80000	Plug	13530
1-4	60000	80000	DWS(1000)	12500
1-4	60000	80000	DWS(2000)	12930
1-4	60000	80000	DWS(4000)	13800
1-6	48000	70000	Normal	11800
1-6	48000	70000	Plug	13530
1-6	48000	70000	DWS(1000)	12270
1-6	48000	70000	DWS(2000)	12780
1-6	48000	70000	DWS(4000)	13860
1-8	30000	50000	Normal	12800
1-8	30000	50000	Plug	--
1-8	30000	50000	DWS(1000)	13650
1-8	30000	50000	DWS(2000)	--
1-8	30000	50000	DWS(4000)	--
1-10	8500	50000	Normal	8400
1-10	8500	50000	Plug	11580
1-10	8500	50000	DWS(1000)	9120
1-10	8500	50000	DWS(2000)	9900
1-10	8500	50000	DWS(4000)	11730
1-12	0.0	50000	Normal	4170
1-12	0.0	50000	Plug	7500
1-12	0.0	50000	DWS(1000)	4590
1-12	0.0	50000	DWS(2000)	5070
1-12	0.0	50000	DWS(4000)	6360

4- Conclusions

1. In cases which there is no economical and demand reasons, the best way for water coning control is to produce gas with a rate below critical.
2. DWS technology is strongly dependent to the allowable water production rate, as allowable water production rate increases, the water cut in gas producing well decreases.

3. DWS technology eliminates the reservoir and wellbore related problems due to coning, but surface and environmental related problems stay an issue yet.
4. In cases which the gas should be produced at a rate above the critical, the best way for water coning control depends on allowable water production rate in DWS technology.
5. As allowable water production rate in DWS technology increases, this technology becomes more efficient.
6. DWS technology is more expensive than plug in, thus using this technology is efficient just for cases the produced water could be used for injection or other purposes.

Nomenclature

BOE	Barrel Oil Equivalent
C1	Methane
CO2	Carbon Dioxide
DWS	Down hole water sink technology
EOS	Equation of state
FWCT	Field water cut
FWPT	Field water production cumulative total
GOR	Gas oil ratio
GR	Group
GWC	Gas water contact
MW	Molecular weight
N2	Nitrogen
PVT	pressure –Volume-Temperature
SCF	Standard cubic feet
STB	Stock tank barrel
WHR	Water Hydrocarbon Ratio

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