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# Rapid Calculation of Well Productivity in Gas-condensate Reservoirs

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## Abstract

The calculation of well efficiency in gas-condensate reservoirs is a significant challenge. Condensate Blockage is assumed as one of the most serious hurdles in Iran's gas reservoirs. When the pressure falls below the dew point pressure, the lower the pressure, the more condensed liquid is formed in the reservoir. Due to the higher pressure difference, this phenomenon is very common in near wellbore regions. If liquids are formed in the reservoir, in addition to the economic losses due to the retention of components with hydrocarbon value, they will also reduce the gas relative permeability and well productivity. The productivity calculation in gas-condensate wells requires performing numerical simulations and downscaling technique of the local grids around the wellbore. Otherwise, the effects of gas velocity as well as the phenomenon of condensate formation around the wellbore are ignored in the calculations, which leads to inaccurate well productivity estimates. The mentioned complexities make the calculation of gas-condensate well productivity more time-consuming while using the numerical simulation method. This paper introduced an analytical method for the rapid calculation of well productivity by considering the effects of velocity and condensate formation around the wellbore with different geometric shapes, including vertical, horizontal, and hydraulically-fractured wells. Then, using Monte Carlo simulation, the effects of uncertainty in different input parameters upon the productivity coefficient were investigated and ultimately a model was presented.

**Disciplinary**: Petroleum Engineering & Technology.



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## Nomenclature

a: half of the major radius of the drainage ellipse around the wellbore

A: flow cross-section area (ft2)

b: half of the minor radius of the drainage ellipse around the wellbore

B: formation volume factor (ft3/SCF)

D: non-Darcy flow coefficient

k: permeability (md)

kro, krw, krg = oil, water, and gas relative permeability

L = horizontal well length (ft)

Lf = hydraulic fracture length (ft)

Pi = initial reservoir pressure (psia)

Pres = reservoir pressure (psia)

Pwf = bottomhole pressure (psia)

P1 = regions 1 and 2 boundary pressure (psia)

Pdew = dew-point pressure

PV = pore volume (ft3)

qg = produced gas flow rate (MSCFD)

$\mu$ = fluid viscosity (cp)

# 1 Introduction

The calculation of well efficiency in gas-condensate reservoirs is one of the significant challenges in such reservoirs. Condensate Blockage is assumed as one of the most serious hurdles in Iran's gas reservoirs. When the pressure falls below the dew point pressure, the lower the pressure, the more condensed liquid is formed in the reservoir. Due to the higher pressure difference, this phenomenon is very common in near wellbore regions. If liquids are formed in the reservoir, in addition to the economic losses due to the retention of components with hydrocarbon value, they will also reduce the gas relative permeability and well productivity.

O'Dell and Miller used the gas rate equation to describe the effect of Condensate Blockage using a pseudo pressure function for the first time. However, their equation was valid only when the pressure was higher than the dew point pressure in most of the reservoirs, and there was only a partial accumulation of condensate around the wellbore [1].

Using hybrid simulations, Fussel proved that the O'Dell and Miller's equation, by considering the available gas in the liquid phase, estimates the productivity reduction much more than usual [2].

Fevang and Whitson [15] presented the most effective method for calculating gas productivity using the pseudo pressure equation. They provided an accurate method for modeling the productivity of gas-condensate wells. Well productivity was introduced using a modified form of the pseudo pressure equation of Evinger and Muskat used to consider the available gas in the oil phase [3].

In this method, the gas/oil ratio along with the reservoir oil properties and relative permeability functions is required to calculate the pseudo pressure. Mott [4] and Xiao and [5] then proposed methods for estimating the radius of the two-phase region of the reservoir that no longer needed to calculate the gas/oil ratio in pseudo pressure equations.

Using the proposed productivity model, Fevang and Whitson [15] showed that the results of Fine Grids Simulation can be obtained again by the pseudo pressure equation. Either in single well reservoirs, using Fine Grids around the wellbore, or in models with more wells, using Grids Refinement around the wellbore, the most accurate method for calculating the productivity of condensate gas wells is microgrid numerical simulation.

Although the hybrid simulation method is an accurate and efficient approach, the need for simpler methods for rapid engineering calculations was also demanded, where the method proposed by Fevang & Whitson could fulfil this requirement.

In this paper, we first introduced an analytical method for the rapid calculation of well productivity in gas-condensate reservoirs. Then, the effects of uncertainty upon the productivity coefficient of vertical, horizontal, and hydraulically-fractured gas- condensate wells were investigated and analyzed.

## 1.1 Rapid Calculation of Well Productivity in Gas-condensate Reservoirs

### 1.1.1 Equation of Gas-condensate Reservoir Rate

The rate equation for pseudo-steady-state (PSS) condition of gas-condensate production with any geometric structure (radial, vertically-fractured, and horizontal) is based on the black oil data as brought in equation [6].

$$q_g = \gamma \int_{P_{wf}}^{P_R} \left(\frac{K_{ro}}{B_o \mu_o} R_s + \frac{K_{rg}}{B_{gd}\, \mu_g}\right) dP \quad (1),$$

Where

$$\gamma = \frac{2\pi\alpha kh}{\ln(\frac{r_e}{r_w}) - 0.75 + s} \quad (2).$$

In [7], the value of α can be 0.00112719 and 1 in the field and the standard units, respectively. The value of γ is a function of the typical characteristics of the reservoir as well as the effects of non-ideal flow including formation damage, well stimulation, drainage form, and partial penetration.

The condensate blocking effect is calculated within the pseudo pressure integral equation. To calculate the pseudo pressure integral, Fevang and Whitson [15] divided the reservoir into several areas, which will be discussed in the following.

## 1.2 Flow Regions

An accurate but simple estimate of the gas-condensate reservoirs requires the definition of three flow regions within the reservoir.

Region 1: The innermost area around the wellbore which includes the simultaneous movement of oil and gas into the reservoir.

Region 2: is the condensate accumulation zone, but only gas can move.

Region 3: where only gas exists.

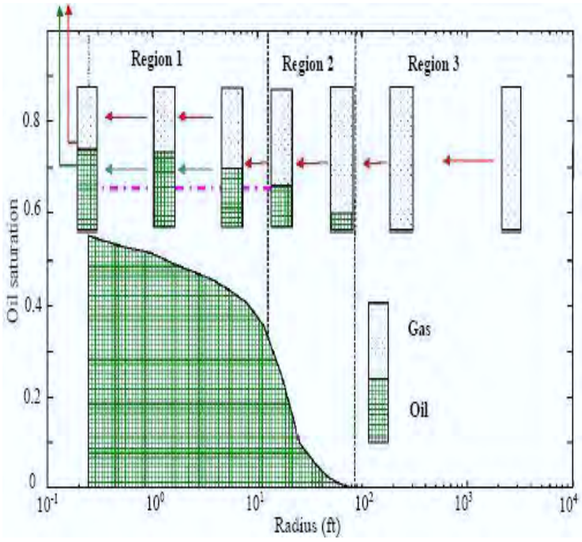


**Figure 1:** The flow regions in gas-condensate reservoirs

Over time, one, two, or all three regions may be present when producing from a reservoir. These three regions give rise to a pseudo-steady production condition, which indicates the stable condition at a particular time and change in the drainage of the reservoir.

**Region 1:**

The composition of the moving fluid in this area is constant. This means that the single-phase gas fluid that enters region 1 is the same fluid produced in the form of gas and condensate from the well. In other words, if the composition of the produced fluid is known, the composition of the flowing fluid inside region 1 is determined and the dew point pressure of the generated fluid at the reservoir temperature is the pressure of the outer radius of the first region, $p_1$.

The most important reason for the decrease in gas-condensate well productivity is the existence of region one, which is due to the high volume of leaked condensate in this region. It must be noted that the size of this region increases over time.

**Region 2:**

This region, if there is one (which it usually is), is the area where the condensate just collects and has no movement. The saturation in the second region is equal to the liquid phase saturation diagram in the constant volume drainage test regarding the reservoir water saturation. The size of this region is maximum primarily when the well pressure falls below the dew point pressure and decreases over time due to the increase in the volume of the first region. When the reservoir fluid enters this region, its concentration decreases and causes the produced fluid to have a lower concentration than the initial concentration in the reservoir.

**Region 3:**

This region includes the part of the reservoir that has a higher pressure than the dew point pressure and its volume decreases over time due to the drop in reservoir pressure. The fluid in this region is the initial fluid in the gas-condensate reservoir.

# 2 Calculation Algorithm

The calculation algorithm of the gas production profile in this study is divided into two subsections. The first section is the time values less than the stabilization period time when the flow rate is constant and equal to $q_{g,\,cons}$. The second section refers to the time values greater than the stabilization period where the bottomhole pressure is constant, $P_{wf}$. [8,9].

In the first section, the trend of the gas production profile is constant, but the ultimate time of the stabilization period is unknown. To determine the stabilization period time, the following steps are performed [10, 11, 12].

a. Using the dry gas equation, the initial bottom hole pressure, $P_{wf,in}$, corresponding to Pi is determined.

b. Assuming the PSS condition in the reservoir, the first trial for the average reservoir pressure $P_{res}$ corresponding to the stabilization period time is calculated using Equation (3): [13].

$$\mathrm{p_{res}} = \mathrm{p_i} + \left(\mathrm{p_{wf,min}} - \mathrm{p_{wf,int}}\right) \quad (3),$$

$$q_g = C\Delta m(P)$$

$$\Delta m(P) = \left\{\int_{p_{dew}}^{p_{res}} \frac{k_{rg}}{\mu_g B_g} dP + \int_{p_1}^{p_{dew}} \frac{k_{rg}}{\mu_g B_g} dP + \int_{p_{wf}}^{p_1} \left(\frac{k_{rg}}{\mu_g B_g} + R_s \frac{k_o}{\mu_o B_o}\right) dP\right\} \quad (4).$$

Since at the end of the stabilization period, the flow rate and $P_{wf}$ are known and are equal to $q_{g,\,cons}$ and $P_{wf,\,min}$, respectively, Equation 6 is written for the estimated value of $P_{res}$ to calculate the experimental value of $P_1$. If the production time is shorter than the reservoir life of the tank, the average reservoir pressure is reduced by ΔP and the calculations are repeated from step B. Otherwise, the production profiles will be plotted and the program will end.

## 2.1 Model Validation

In order to validate the introduced model, the results of this model are compared with the results obtained from a hybrid commercial simulator. Numerical simulation is considered as a single well model with a radius of 0.58 ft with fine grids around the wellbore and in the center of a homogeneous reservoir with dimensions of 6000 × 6000 ft. The average porosity and permeability of the reservoir are assumed to be 10% and 50 md, respectively. To avoid numerical error due to grid dimensions in the hybrid simulator, the simulation was repeated by dwindling the grid dimensions. When the results did not change as the grid size became smaller, the grid dimensions were selected as the optimal dimensions for comparison with the analytical model. Several samples of condensate gas with condensate to gas ratios of 166, 71 and 7.32 bbl/1000ft$^3$ were used as rich, medium and light condensate fluids, respectively.

Different reservoir rock samples have been tested for relative gas and oil permeability. The relative permeability of each sample is estimated using Corey Equation. The pertinent parameters of the rock samples used in the validation stage are given in Table 1. Also, in terms of the effects of velocity on relative permeability and in order to coordinate it with the analytical model, the key related to Veldep-dependent permeability as well as the Whitson empirical correlation have been employed in the numerical simulator.

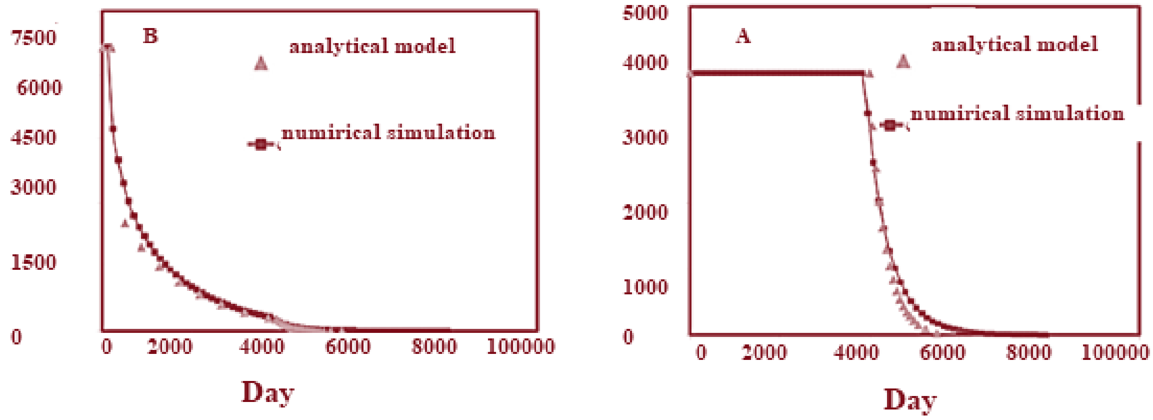


**Figure 4:** Comparison of production changes in (a) gas, (b) condensate for the rich fluid sample and the third rock sample in the horizontal well for both analytical and simulation models.

To ensure the accuracy of the results of this model for horizontal and fractured wells, samples of such wells have also been examined. Therefore, for each well with a specific geometric shape, the results of the analytical model and numerical simulation were determined for six different rock and fluid samples. Table 2 summarizes the average error of different rock and fluid samples in the results of the developed analytical model compared to the numerical simulator for three different well geometries (as a percentage). A comparison of gas and condensate production profiles for one of the cases with the highest observed error (horizontal well for rock sample 3 with rich fluid) is illustrated in Figure 4. As can be seen from Table 2, the average error rate is less than 5%, which is quite acceptable in petroleum engineering calculations. The average time to perform the calculations in the analytical model (in the range of less than 1 min) is faster than the numerical simulator (in the range of 10 min). However, the advantage of the analytical model is not in the execution speed, but it is due to the possibility of performing sensitivity analysis on reservoir and well data and its effect on the duration of gas and condensate stabilization period and the produced volume of gas and condensate. In order to investigate the effect of uncertainties in both numerical and analytical methods and to limit the difference between the results of these two approaches, the porosity parameter has been selected as the uncertain parameter. Porosity was considered as a normal distribution function with a median of 0.1 and a standard deviation coefficient of 0.08.

**Table 1:** Corey equation parameters for plotting relative permeability diagrams.

| Rock Type | $S_{wi}$ | $k_{rgmax}$ | $n_g$ | $S_{gmin}$ | $S_{gmax}$ | $k_{romax}$ | $n_o$ | $S_{omin}$ | $x_{Soma}$ |
|---|---|---|---|---|---|---|---|---|---|
| SCAL 1 | | | 1.5 | | | | 1.5 | 0.15 | |
| SCAL 2 | 0.1 | 0.6 | 4.5 | 0.3 | 0.9 | 0.3 | 1.5 | 0.35 | 0.6 |
| SCAL 3 | | | 3 | | | | 3 | 0.35 | |

**Table 2.** Comparison of the results of the analytical model and numerical simulator

| Produced condensate profile | Gas flow rate profile | | Bottomhole pressure profile (psia) | Well shape |
|---|---|---|---|---|
| | Stabilization period length | Stabilization period | | |
| 2.2 | 2.03 | 1.84 | 2.5 | vertical |
| 3.6 | 3.7 | 3.23 | ¼ | horizontal |
| 2.67 | 2.1 | 1.46 | 1.89 | Hydraulic fracture |

The cumulative production values for gas and condensate after 40 years as well as the duration of the gas stabilization period for one thousand times run by Monte Carlo method for both analytical and numerical approaches are compared in Table 3.

## 2.2 Sensitivity Analysis of the Uncertain Data

In this section, the effects of uncertainty of different well and reservoir parameters on the values of cumulative gas production, cumulative condensate production and stabilization period will be investigated. For this purpose, Monte Carlo analysis methods have been utilized. Thus, for each study, a thousand probabilities are set for the desired uncertain parameter, and for each probability, the cumulative production values of gas and condensate, as well as the length of the stabilization period are calculated by the method introduced in this paper, and then are analyzed by employing the tornado diagram. In the following, the medium fluid and the relative permeability form of rock No. 4 are also considered as the sample fluid and the reference diagram of the relative permeability of the reservoir rock. The production profile of this reservoir is shown in Figure 5. The results of the uncertainty studies of vertical, horizontal and fractured wells data are given below.

**Table 3:** Possible values for calculating the productivity of a vertical gas-condensate well for uncertainty in the input data.

| Possible results P50 | | Parameter |
|---|---|---|
| Numerical model | Analytical model | |
| 12.93 | 12.6 | Cumulative gas production (billion ft3) |
| 0.234 | 0.278 | Cumulative condensate production (million bbl) |
| 15.77 | 15.64 | Stabilization time (days) |

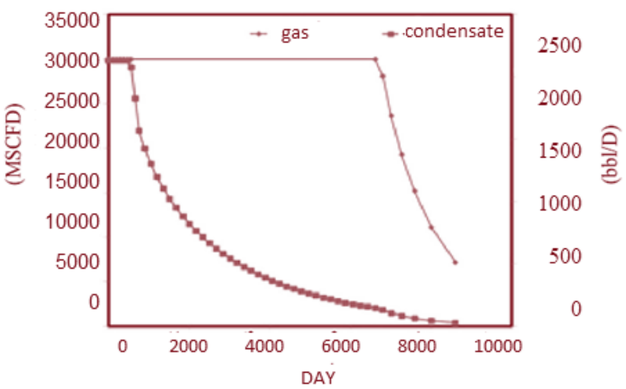


**Figure 5:** Changes in vertical gas-condensate well production for the base state

## 2.3 Vertical Wells

In this section, the sensitivity analysis is performed upon the input data in accordance with Table 4 for the vertical gas-condensate well in order to find the important parameters affecting the well productivity. Table 5 shows the values of P10, P50, and P90 for the stabilization period and the cumulative production of gas and condensate after 40 years.

Based on the results in Table 5, the probable range of results for the stabilization duration as well as the cumulative production of gas and condensate is wide. To show the effect of each uncertain parameter in the input data upon the output results, the tornado diagram is plotted in Figures 6 to 8. According to Figure 8, to reduce the cumulative gas production range, uncertainty in porosity, permeability, initial water saturation, minimum bottomhole pressure and external radius of the reservoir should be more limited. According to the results of Figure 7, porosity, permeability and external radius of the reservoir are the most important uncertain parameters affecting the cumulative production of condensate in the vertical gas-condensate well. According to Figure 8, the reduction in permeability uncertainty, skin factor, porosity, initial water saturation, minimum bottomhole pressure, and flow rate can lead to a reduction in the stabilization period duration in vertical gas-condensate wells. Based on Figures 6 and 7, porosity is the most important factor affecting the cumulative production of gas and condensate. According to Figures 6 and 7, porosity is the most significant factor affecting the cumulative production of gas and condensate. This can be attributed to the direct effect of porosity on the volume of gas and condensate. Uncertainty in porosity also affects the duration of the stabilization period. However, according to Figure 8, the contribution of permeability and skin factor over the stabilization period is greater. It should be noted that based on the expectation and according to the Tornado diagram in Figure 8, the permeability and the duration of the stabilization period have a negative correlation and the higher permeability estimate causes a lower estimate of the stabilization period.

**Table 4.** Probability distribution function of input data for studying the sensitivity analysis of vertical gas-condensate well

| Distribution function | Input data |
|---|---|
| Triangular distribution with a minimum value of 2500 ft, an average of 3000 ft, and a maximum of 3500 ft | Outer radius of the reservoir |
| Uniform distribution with a minimum value of 1000 psia and a maximum of 1500 psia | Minimum bottomhole pressure |
| Uniform distribution with a minimum value of 3- and a maximum of 10 | Skin factor |
| Uniform distribution with a minimum value of 30 and a maximum of 50 | stabilization period rate (billion $ft^3$) |
| Normal log distribution with a median of 20 md and a standard deviation of 40 md | permeability |
| Uniform distribution with a minimum value of 0.05 and a maximum of 0.4 | Initial water saturation |
| Normal distribution with a median of 0.1 and a standard deviation of 0.08 | porosity |
| Normal log distribution with a median of 0.58 and a standard deviation of 0.2 | $K_{rgmax}$ |
| Uniform distribution with a minimum value of 1.5 and a maximum of 3 | $n_g$ |

**Table 5.** Probable values for calculating the productivity in vertical gas-condensate wells for uncertainty in the input data.

| Probable results | | | Parameter |
|---|---|---|---|
| P10 | P50 | P90 | |
| 20.63 | 12.6 | 6.67 | Cumulative gas production (billion ft3 standard) |
| 0.134 | 0.275 | 0.0453 | Cumulative condensate production (million barrels) |
| 28.77 | 15.64 | 4.52 | Stabilization time (days) |

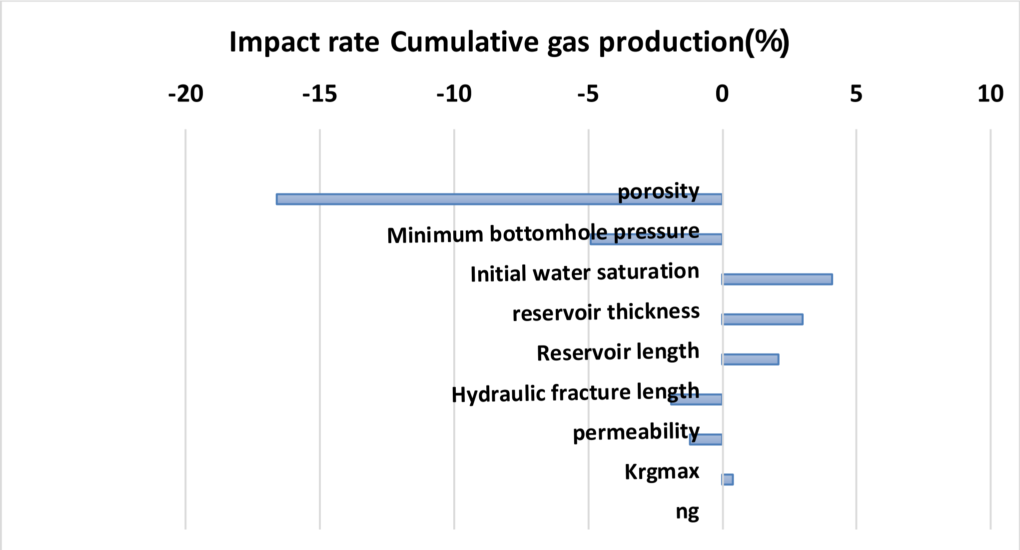


**Figure 6:** Tornado diagram to show the effect of uncertainty in each of the input data on the cumulative gas production for the vertical well.

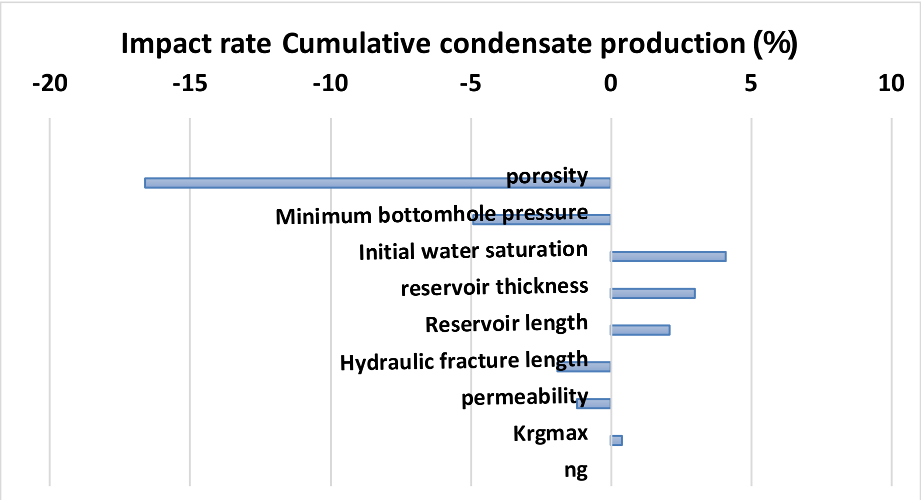


**Figure 7:** Tornado diagram to show the effect of uncertainty in each of the input data on the cumulative condensate production for the vertical well.

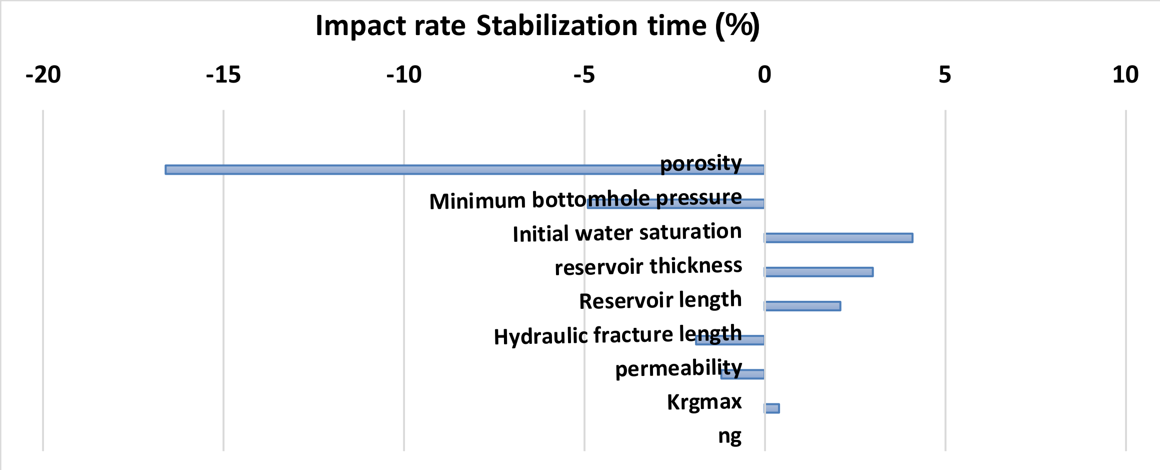


**Figure 8:** Tornado diagram to show the effect of uncertainty in each of the input data on the duration of the stabilization period for the vertical well.

## 2.4 Horizontal Wells

In this section, the sensitivity analysis is performed on the input data in accordance with Table 6 for horizontal gas-condensate wells to find the important parameters affecting the well productivity.

**Table 6:** Probability distribution function of input data for studying the sensitivity analysis of horizontal gas-condensate well

| Distribution function | Input data |
|---|---|
| Uniform distribution with a minimum value of 1000 ft and a maximum of 4000 ft | Horizontal well length |
| Uniform distribution with a minimum value of 4000 ft and a maximum of 7000 ft | Reservoir length |
| Uniform distribution with a minimum value of 4000 ft and a maximum of 7000 ft | reservoir thickness |
| Uniform distribution with a minimum value of -3 and a maximum of 10 | Skin factor |
| Uniform distribution with a minimum value of 30 and a maximum of 140 | Stabilization period flow rate (billion $ft^3$) |
| Normal log distribution with a median of 20 md and a standard deviation of 40 md | Permeability (md) |
| Uniform distribution with a minimum value of 0.05 and a maximum of 0.4 | Initial water saturation |
| Normal distribution with a median of 0.1 md and a standard deviation of 0.08 | Porosity |
| Normal log distribution with a median of 0.58 md and a standard deviation of 0.2 md | $K_{rgmax}$ |
| Uniform distribution with a minimum value of 1.5 and a maximum of 3 | $n_g$ |

Table 7 shows the values of P50, P10, and P90 for the stabilization period as well as the cumulative gas and condensate production after 40 years in horizontal gas-condensate wells. To show the effect of each uncertain parameter in the input data upon the cumulative gas production, a tornado diagram is plotted in Figure 6.

**Table 7:** Probable values for calculating the productivity in horizontal gas-condensate wells for uncertainty in the input data**.**

| Probable results | | | Parameter |
|---|---|---|---|
| P10 | P50 | P90 | |
| 12.57 | 12.68 | 7.58 | Cumulative gas production (billion $ft^3$ standard) |
| 0.498 | 0.267 | 0.144 | Cumulative condensate production (million barrels) |
| 30.7 | 21.7 | 8.9 | Stabilization time (days) |

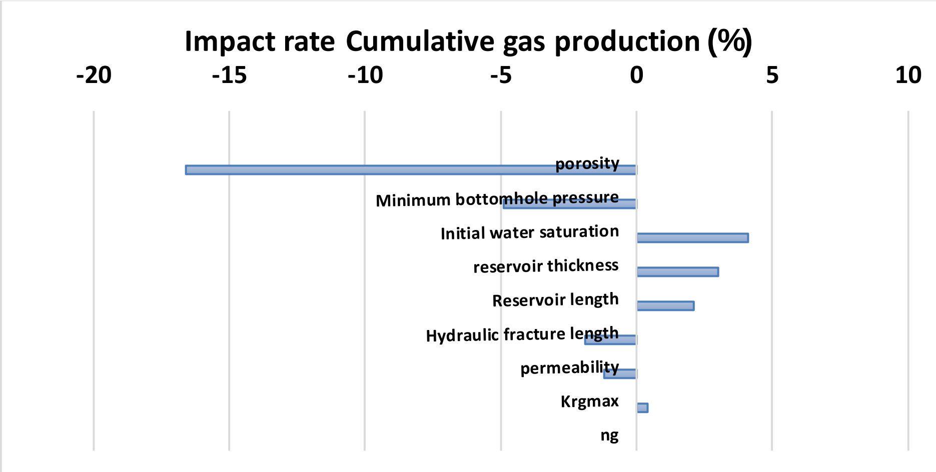


**Figure 9:** Tornado diagram to show the effect of uncertainty in each of the input data on the duration of the stabilization period for the horizontal well**.**

According to Figure 9, the uncertainty parameters affecting the cumulative gas production in horizontal gas-condensate wells are porosity, $K_{rgmax}$ (SCAL data), and initial water saturation. According to the interpretation of the Tornado diagram results for the condensate cumulative production, porosity, permeability, initial water saturation, and $K_{rgmax}$ (SCAL data) is the most significant uncertain parameters affecting the cumulative production of condensate in the horizontal gas-condensate wells. Based on the interpretation of tornado diagram results for the duration of the stabilization period, uncertainty in permeability, porosity, skin factor, initial water saturation has an important effect on determining the duration of the stabilization period in horizontal gas-condensate well. In the sensitivity analysis related to horizontal wells, due to the significance of porosity on the number of hydrocarbons in place, it has the greatest effect on the cumulative production of gas and condensate as well as the duration of the stabilization period. In horizontal wells, as expected, permeability has a negative correlation with the duration of the stabilization period and thus is assumed as the most important parameter with uncertainty. It should be noted that the stabilization period flow rate, as well as the length of the horizontal well, do not affect the volume of cumulative production of gas and condensate. This is due to the fact that these parameters affect the well production and have no effect on the reservoir ultimate recovery. Also, the stabilization period flow rate and the length of the horizontal well have a minor effect on the duration of the stabilization period and the cumulative production of gas and condensate phases.

## 2.5 Hydraulically-fractured Wells

In this section, the sensitivity analysis is performed upon the input data according to Table 6 for gas-condensate wells with hydraulic fractures to find the important parameters affecting the well productivity. The fracture length in this analysis is considered to be uniformly distributed with a minimum value of 100 and a maximum of 400 ft. Table 8 shows the values of P10, P50, and P90 for the stabilization period as well as the cumulative production of gas and condensate after 40 years for gas-condensate wells with hydraulic fractures. To show the effect of each uncertain parameter in the input data upon the output results, a tornado diagram is plotted in Figure 10.

According to Figure 10, the most important parameters with uncertainty affecting the cumulative gas production in gas-condensate wells with hydraulic fractures include porosity, minimum bottomhole pressure, and initial water saturation.

**Table 8:** Probable values for calculating the productivity in a hydraulically-fractured gas-condensate wells for uncertainty in the input data.

| Probable results | | | Parameter |
|---|---|---|---|
| P10 | P50 | P90 | |
| 29.3 | 14.1 | 7.73 | Cumulative gas production (billion $ft^3$ standard) |
| 0.599 | 0.31 | 0.166 | Cumulative condensate production (million barrels) |
| 20.7 | 10.3 | 5.4 | Stabilization time (days) |

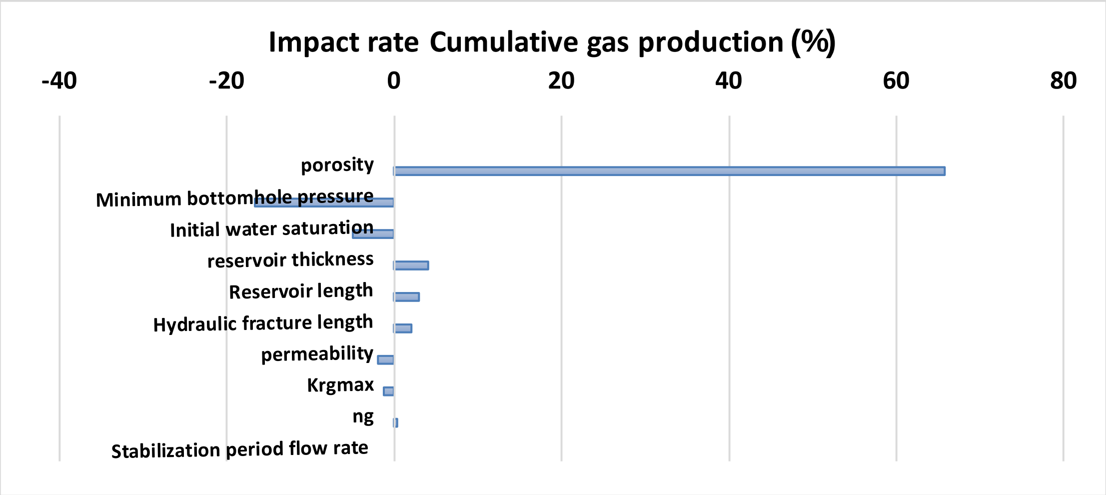


**Figure 10:** Tornado diagram to show the effect of uncertainty in each of the input data on the cumulative gas production in the fractured gas-condensate well

According to the interpretation of the Tornado diagram results for the cumulative production of condensate, porosity, minimum bottomhole pressure, and initial water saturation are the most important uncertain parameters affecting the cumulative production of condensate in a fractured gas-condensate well. According to the interpretation of the tornado diagram results for the duration of the stabilization period, uncertainty in porosity, minimum bottomhole pressure, stabilization period flow rate, and initial water saturation have important effects on determining the duration of the stabilization period in gas-condensate wells with hydraulic fracture. In wells with hydraulic fractures, porosity and initial water saturation, due to their considerable effect on in-situ hydrocarbon volume, have the greatest uncertainty in the volume of hydrocarbon production as well as the duration of the stabilization period.

In this well, because of the negative skin factor and thus the increase in permeability around the wellbore due to hydraulic fracture, uncertainty in the permeability parameter is not significant and the minimum bottomhole pressures as well as the stabilization period flow rate are effective in determining the duration of the stabilization period. Also, the length of the hydraulic fracture is less important than other parameters in determining the duration of the stabilization period

## 3 Conclusion

In this study, a rapid analytical method with Monte Carlo simulation was utilized to study the effects of uncertainty in the input data upon the probable results of productivity calculation in vertical, horizontal, and hydraulically fractured gas-condensate wells.

The results showed that in the reservoir model studied in this paper, the porosity is the most important input parameter with uncertainty in the probable results of the analytical model of the gas-condensate well during the stabilization period, and the cumulative production of gas and condensate phases in wells with different geometric shapes. Porosity, permeability, skin factor, and initial water saturation were the most important uncertain parameters in calculating the duration of the stabilization period and hence making decisions for field development in the studied reservoir. It must be noted that the accurate determination of some parameters (such as empirical constants in correlations of velocity-dependent relative permeability) is experimental, time-consuming, and expensive. However, their changes do not have a significant effect on gas-condensate well output results. The results of such a study guide the reservoir engineers to understand which of the uncertain reservoir data is more important and how the efforts and budgets need to be spent precisely to determine that specific reservoir data. Obviously, the most important uncertain data mentioned in this study was related to the reservoir and it is necessary to do a similar study for other gas-condensate reservoirs. Also in this research, an analytical model for a homogeneous reservoir and a centralized well was developed. It is appropriate to develop such an analytical model to investigate the cases of decentralized wells, the effect of heterogeneity in reservoir permeability, and the wells with different geometric shapes such as inclined ones.

## 4 Availability of Data and Material

All information is included in this study.

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