JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

Investigation of hydrocarbon potential of Hosseinieh Fahlian anticlines in Yadavaran oil field

Hooman Fallah[1] Farzad Asadi[2,*], Hossein.Maghsoudnia [3]

1. Ahar Mining Engineering Group, Islamic Azad University, Iran, Ahar,

Email:H.fallah6345572@gmail.com

2. Department of Mining Engineering, Islamic Azad University-Lahijan,Guilan Iran,

Email: Si.company@rocketmail.com

3. Department of Mining Engineering, Islamic Azad University- South Tehran Branch, Tehran, Iran, Email: Hossein.maghsoudnia13@gmail.com

Received: 2022 March 15; **Revised:** 2022 April 20; **Accepted:** 2022 May 10.

Abstract

Based on geological and physical information about the characteristics of an oil, gas or gas condensate field, considering the capabilities of its systems and development technologies gives few notions about the development of this field in general.

System of quantitatively related ideas about the development of a field is a model of its development that consists of a reservoir model and a model of the field development process. Early extraction of 20,000 barrels of light oil per day from the Fahlian layer through eight wells was defined. From this field, two types of heavy oil and light oil are produced from the two layers of Sarvak and Fahlian, respectively.

The static and dynamic three-dimensionality of the well drilling process and the use of a segmental model are selected to investigate the whole field.

Keywords: well pressure, well pressure, segmental simulation, reservoir, well production

Introduction

Gringarten (2011) indicated that making more accurate models with less error will partially express the actual behavior of the reservoir due to the significance and strong influence of geological models of reservoirs from indeterminate parameters. Bickel et al,. conducted a study in 2008 on the current uncertainty of the two oil and gas industries and the decision-making under those conditions to answer these two questions: 1) Has the uncertainty in the oil and gas industry decreased (improved) in the last 10 years? 2) Does this improvement rely on decision-making systems? The answer to the first question was "yes" and the second question was qualitatively "no", in which the decision-making tool was practiced to reduce uncertainty.

The use of potential modeling has been increasing in the oil and gas industry over the past 10 years, as evidenced by the numerous publications of the Institute of Petroleum Engineers. As an example, the table below illustrates the list of conferences held by this institute from 1979 to 2007 in the field of uncertainty, forecasting or decision-making. Haugen deliberated reserve size uncertainty in 1996 and used the "probabilistic dynamic planning" model so as to schedule oilfield projects. Moreover, Lund used this method in 2000 to assess the value of flexibility in oil and gas projects under the uncertainty of oil prices and the volume of reserves in the oil field. Many apapers have been presented to shrink exogenous uncertainties, but far fewer studies have been conducted on endogenous uncertainties. In 2001, G¨uyaguler evaluated the uncertainty in optimizing the location of drilling wells. Estimating the best position for drilling new wells in exploration is a complex problem that depends on the characteristics of the reservoir, wells, surface equipment, and economic criteria (Hage, Rian, 1994), (Song, Beckner, 1995), (Eide, Aanonsen, 1995) (Horne, Bittencourt, 1997), (Horne, Pan, 1998), (Crawford, Stoisits, 1999), (Centilmen et al., 1999), (Rogers, Johnson, 2000), (G¨uyag¨uler et al., 1997) (DeGroot, 1970. Simulation is often the most appropriate tool for evaluating flexibility and feasibility of wells.

Nonetheless, this uncertainty is also transferred to the simulated model, which in turn will affect the optimal estimation of the drilling site since the data used in the simulation are associated with uncertainty of their kind. Reservoir modeling resulting from the integration of seismic information and well-logging logs has been a significant concern of many researchers. (Xu et al., 1992; Eidsvik et al., 2001; Mukherijee et al., 2001; Larsen et al., 2006; Dubrule, 2003). Combining seismic information within a random function can be done using deterministic interpolation algorithms such as the State Adjoint method (Qian, Leung, 2006), simulated annealing method (Stoffa, Sen, 1995), kriging with external drift (Govaerts, 1997), cokriging (Dubrule, 2003), random simulation (Xu et al., 1992).

Non-critching simulation methods such as Monte Carlo simulation of the Markov chain (Larsen et al., 2006) have also been used to model the main reservoir parameters. Reservoir simulation is a type of numerical modeling that allows the determination and interpretation of physical phenomena in the reservoir and even their prediction. The most important limitations of reservoir simulators are: 1- using macro-scale observations and experiments such as seismography to find parameters in the scale Real Micro 2- Increasing the scale of the repository in great detail to a scale and size manageable for the computer 3- Some uncertainties in the model describing the reservoir.

Methods:

The finite difference method is a simple method for solving partial differential

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

equations in which derivatives are expressed as definite differences. Note Figure 2:

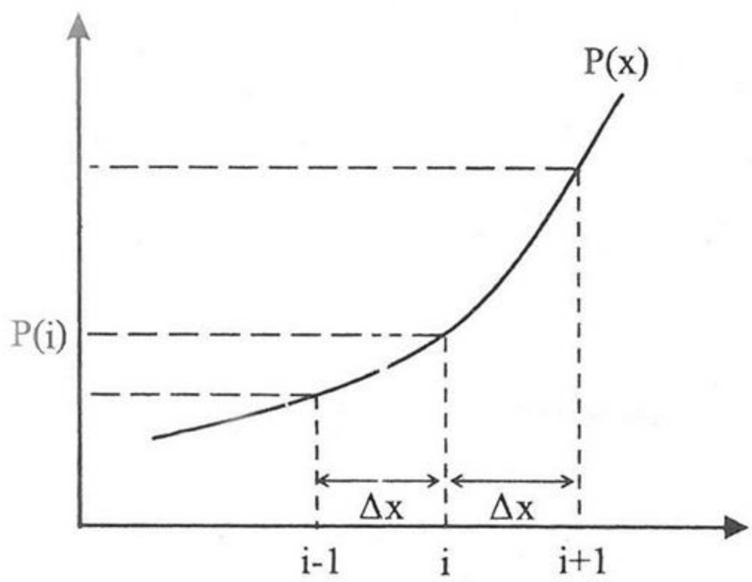

Fig2. Derivative of the function P (x) in the form of finite differences

In this diagram, the derivative of the function at the point, that is, can be expressed as finite differences. The three main methods of finite differences are as below:

1-Forward Differences

$$\left(\frac{dP}{dx}\right) = \frac{P_{i+1}}{\Delta x}$$

(1-1)

1- Backward difference

(2-1)

$$\left(\frac{dP}{dx}\right) = \frac{P_i - P_{i-1}}{\Delta x}$$

3-Central difference

(3-1)

$$\left(\frac{dP}{dx}\right) = \frac{P_{i+1} - P_{i-1}}{2\Delta x}$$

Note that the accuracy of the middle method is greater than the accuracy of the forward and backward methods. Higher order derivatives are obtained in the same way.

Consider that the accuracy of the middle method is greater than the accuracy of the forward and backward methods. Higher order derivatives are obtained in the same way.

For example, Equation 1-4 illustrates the second-order derivative using the central difference method.

(4-1)

$$\frac{\partial^2 P}{\partial x^2} = \frac{\partial}{\partial x}\left(\frac{\partial P}{\partial x}\right) = \frac{P_{i+1} - 2P_i + P_{i-1}}{(\Delta x)^2}$$

3-4-2- Explicit, implicit, and IMPES solution methods

Liquid flow in a linear system and one-dimensional porous medium is expressed by Equation 1-5: =

$$\frac{\partial^2 P}{\partial x^2} = \frac{1}{n}\frac{dp}{dt} \quad (5\text{-}1)$$

where in:

Pressure , psi

The length of the porous medium, ft

Flow duration, day

Emission coefficient, ft^2/day

Suppose this equation is supposed to be solved by the finite difference method. Both Equations 1-6 and 1-7 can decompose Equation 1-5 into finite differences. The pressure parameter to the left of Equation 1-6 is used in the present; Nonetheless, the same parameter is used in the future on the left side of Equation 1-7.

$$\frac{p_{i+1}^{t} - 2p_i^{t} + p_{i-1}^{t}}{(\Delta x)^2} = \frac{1}{n}\frac{p_i^{t+1} - p_i^{t}}{\Delta t} \quad (6\text{-}1)$$

$$\frac{p_{i+1}^{t+1} - 2p_i^{t+1} + p_{i-1}^{t+1}}{(\Delta x)^2} = \frac{1}{n}\frac{p_i^{t+1} - p_i^{t}}{\Delta t} \quad (7\text{-}1)$$

The first method, in which there is only one unknown parameter in the future ()p_i^{t+1}(), is called the explicit method.

The second method, in which there are three unknown parameters in the future tense (p_{i+1}^{t+1}, p_{i-1}^{t+1}andp_i^{t+1}), is called the implicit method.

To solve an equation explicitly, the existence of the same equation is sufficient, there is an equation for each unknown one. Two other equations are necessary to solve the equation implicitly. In other words, it is necessary to solve three finite difference equations simultaneously so that these three unknowns are obtained.

Reservoir fluids in eclipses

Figure 3. illustrates the pressure-temperature diagram shows a multi-component hydrocarbon system. The black dot at the top of the chart is called the critical point. The left curve is called the critical point, the bubble point curve and the right curve is called the dew point curve. Their combination creates a semi-closed curve, which is called envelope phase. Reservoir fluids are biphasic inside the fuzzy cap and monophasic outside.The pressure drop figure displays the isothermal temperature of hydrocarbon fluids under different conditions. Line A indicates unsaturated oil. In the Eclipse simulator, the oil above the bubble point is called dead oil. The reason for this naming is that the soluble gas has no influence (due to its stability) on the fuzzy behavior of the fluid

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

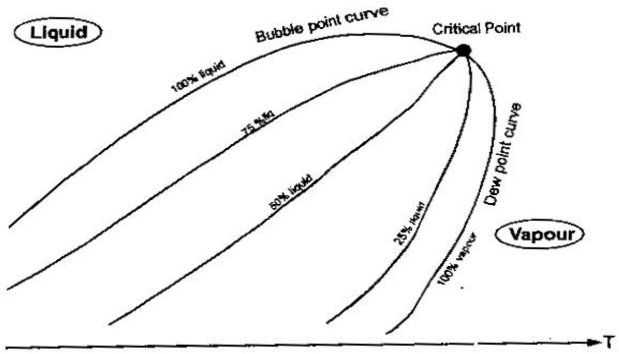

Fig3. P-T diagram of a multi-component hydrocarbon system

Line B divulges the important black oil that was initially above the bubble point and is released as the pressure drops and the dissolved gas curve breaks. The gas released in the tank forms a gas cap and the gas released in the well is produced at ground level. This fluid is called live oil in the Eclipse simulator. And line C denotes a two-phase mixture. At the top of the GC, the pressure is less than the bubble point pressure and the gas exists in a free phase (gas cap). At the bottom of the GOC, the pressure is higher than the bubble point pressure and the oil contains dissolved gas.

In the Eclipse simulator, this fluid is also called living oil. Line D signifies the single gas oven fluid. As the pressure declines, the dew point curve never breaks, consequently, the amount of oil evaporated in the gas remains constant. This fluid is called dry gas in the eclipse simulator.

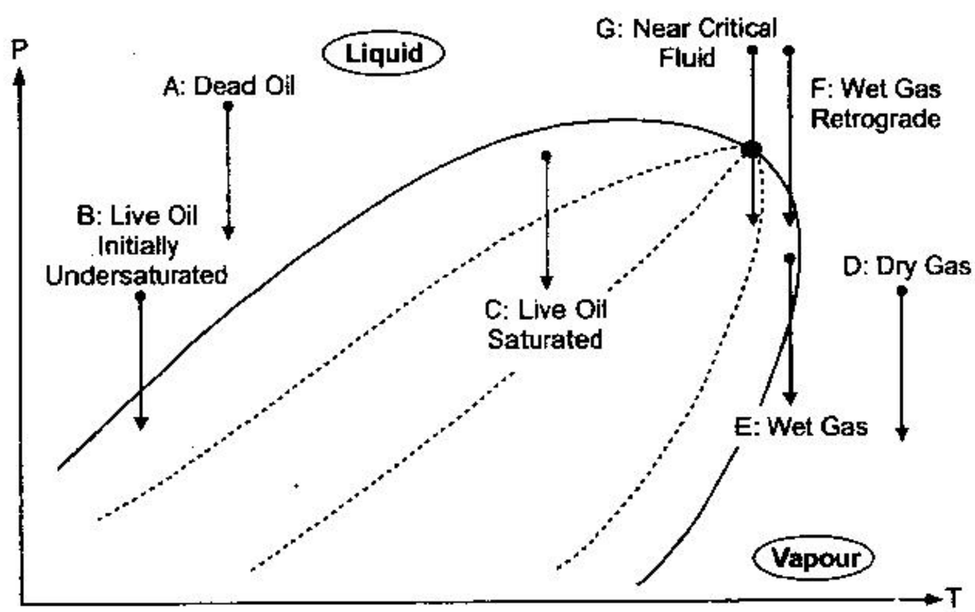

Fig4. Different fluids in the Eclipse simulator

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

Line E represents a two-phase mixture that is initially positioned inside the fuzzy shell. As the pressure decreases, the liquid gradually evaporates until no liquid remains, in other words, the dew point line is cut off. This fluid is called the wet gas in the Eclipse simulator.

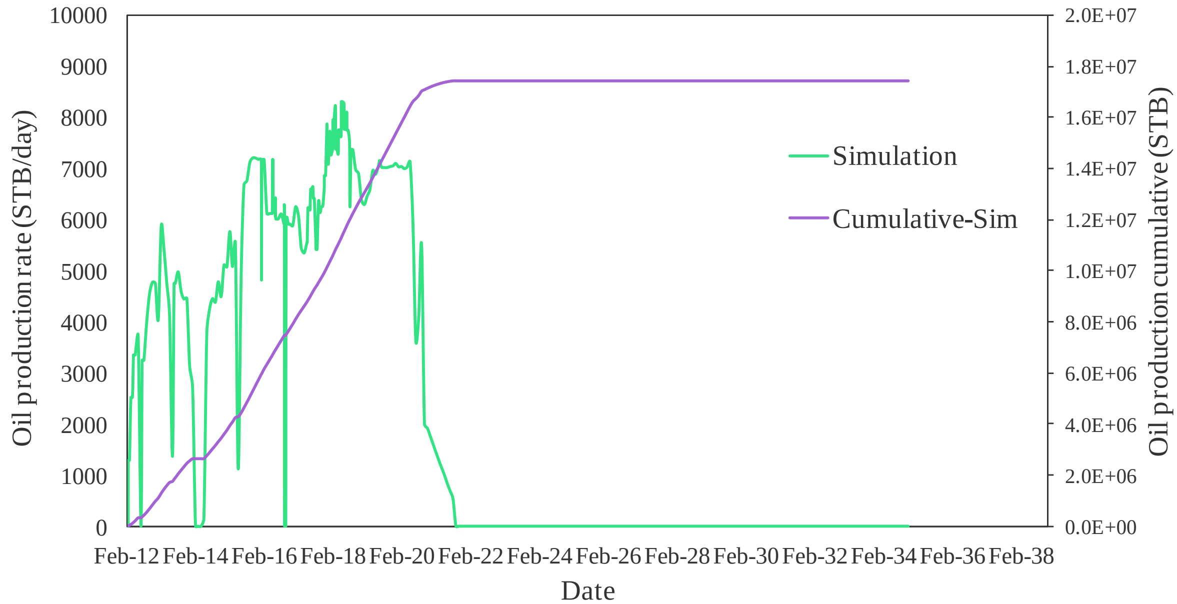

Fig5. Well No F5

Well No: 5

In well No:5, the cumulative amount reaches more than STB/day 8000 and discharge reaches to 8000STB/day at its highest value. From the day twenty second onwards, its amount reaches zero. It has gas production, whereas, there is no water production.

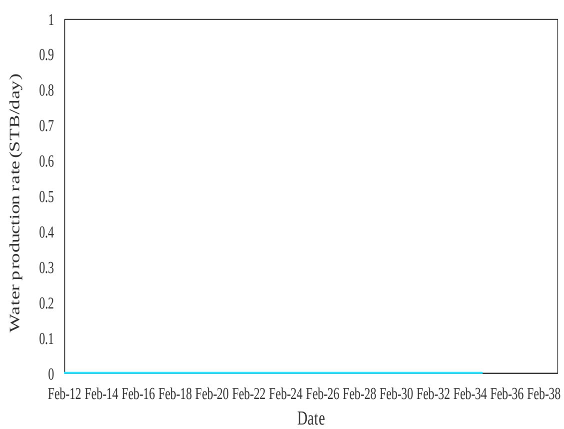

Fig6. Water production

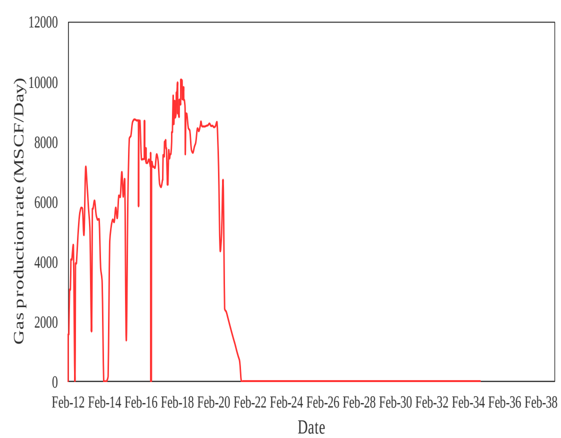

Fig7. Gas production

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

In well No 5, the amount of gas reaches to its highest amount which is 1000psi. From the twenty second day onwards, it reaches zero. Furthermore, the amount of water production reaches zero in well No:5. In Well No : 5, there are pressures both on top and at the bottom of the well.

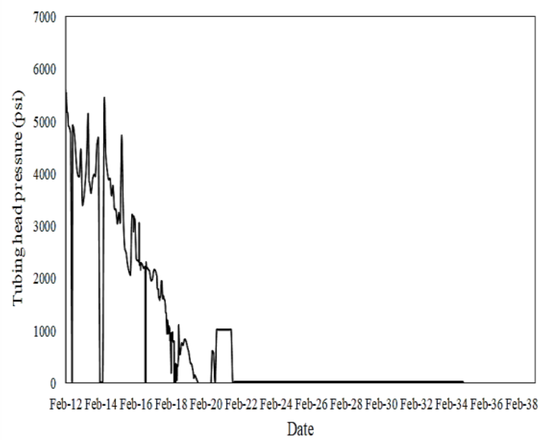

Fig8. Well pressure

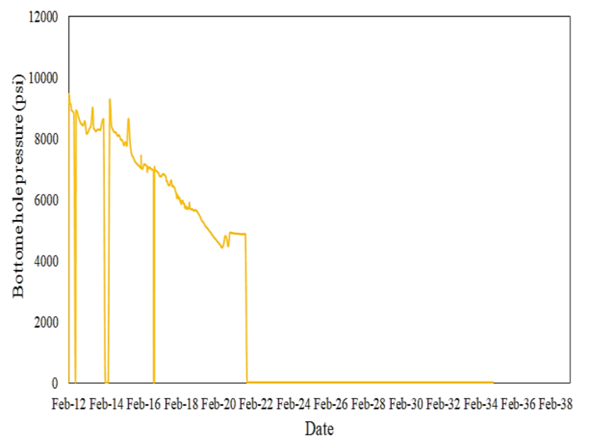

Fig9. Pressure to the well

In well No 5, the pressure value at the bottom of the well is more than 8000psi at its highest amount. In its lowest amount, it reaches more than 4000psi. From the twenty second day onwards, the pressure at the bottom of the well reaches zero.

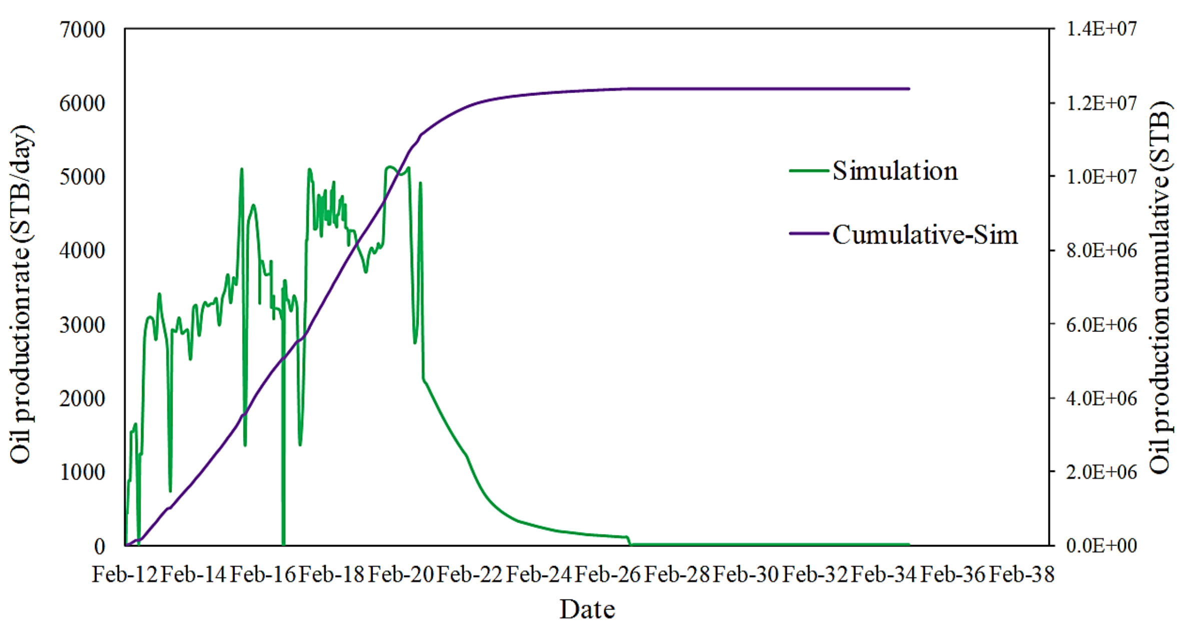

Fig10.Well No F7

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

Well No 7:

In well No7, the cumulative amount reaches 6000STB/day and discharge reaches to its highest amount which is 5000STB/day. From the twenty sixth day onwards, the amount of gas will finally reach zero. In well No: 7, there is gas production and there is no water production.

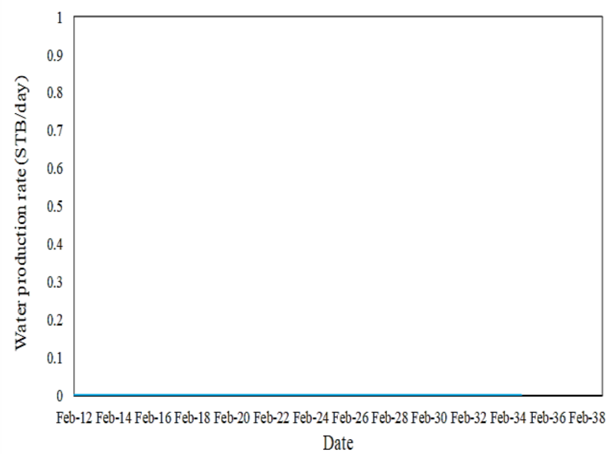

Fig11. Water production

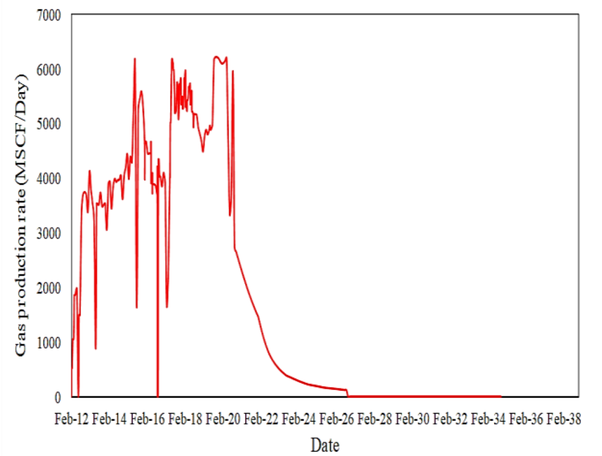

Fig12.Gas production

In well No 7, the value of gas and water is scrutinized. In this well, gas reaches to its highest amount which is 6000MSCF/Day. Its lowest amount reaches more than 1000MSCF/Day . From the twenty sixth day onwards, the amount of gas will finally reach zero. The amount of water production reaches zero in well No 7. In well no 7, there are both pressure at the top and bottom of the well.

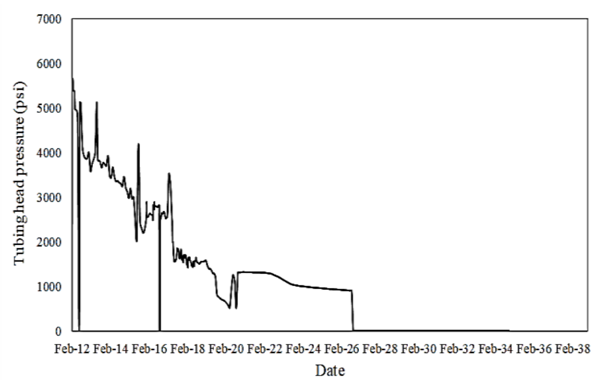

Fig13. Well pressure

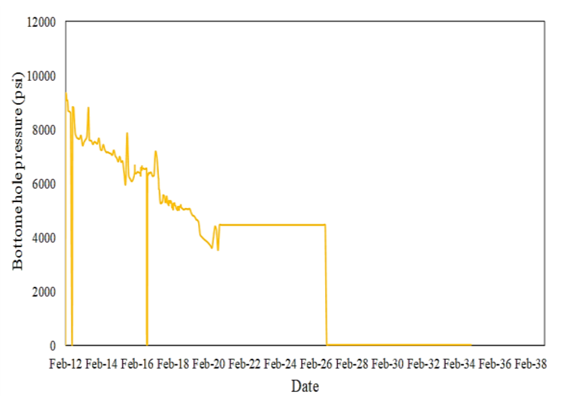

Fig14. Pressure to the well

In well No: 7, the oil production at the pressure at the bottom of the well is 8000psi. the lowest amount is 4000psi. From the twenty sixth day onwards, the amount of gas will finally reach zero. Eventually, the pressure on top of the well is at its highest value which is 5000psi in well Npo:7. Its lowest amount reaches 1000psi. from the twnty sixth day onwards, the pressure at the top of the well reaches zero in well No:7.

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

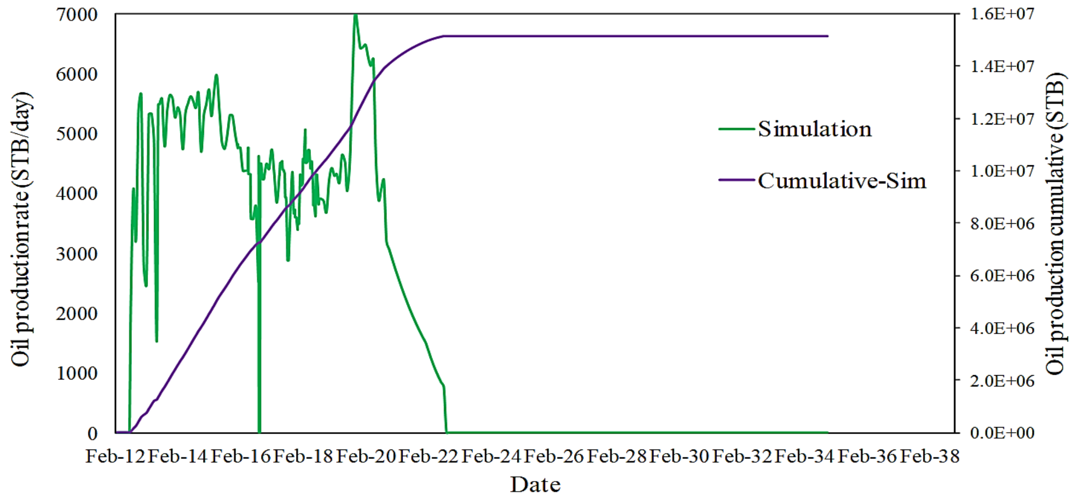

Fig15. Well No F8 (F8Well)

Well No 8:

In well No: 8, the cumulative value in its maximum value reaches more than 6000psi and its discharge value reaches its maximum value of 7000psi.

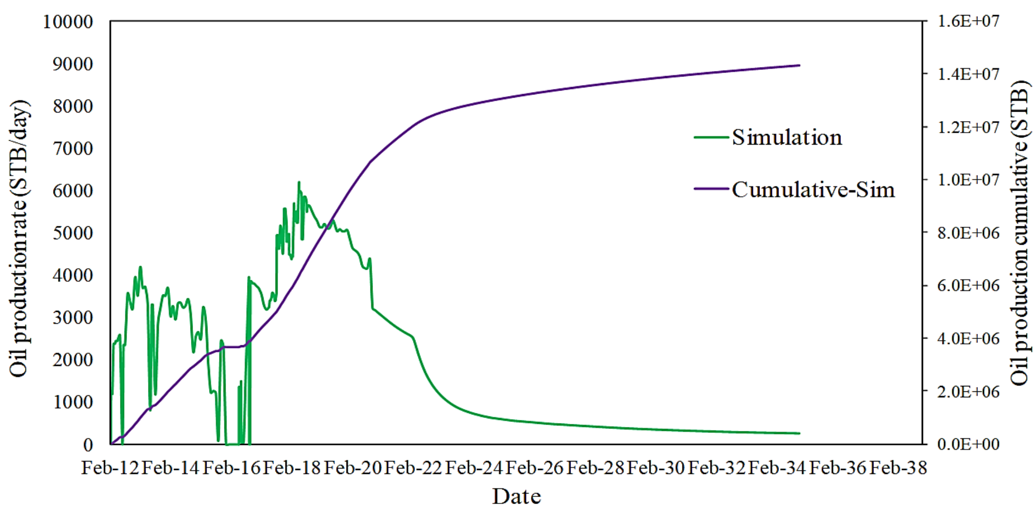

Fig16. Hosseinieh well (HOS2-ST1 Wel)

Hosseinieh well:

In Hosseinieh well, the cumulative amount reaches 9000STB / day. The amount of oil production produced in Hosseinieh well reaches 6000 STB / day in its maximum amount and its least amount is less than 3000 STB / day and finally reaches zero (0). Hosseinieh well has gas production. It does not have zero water production.

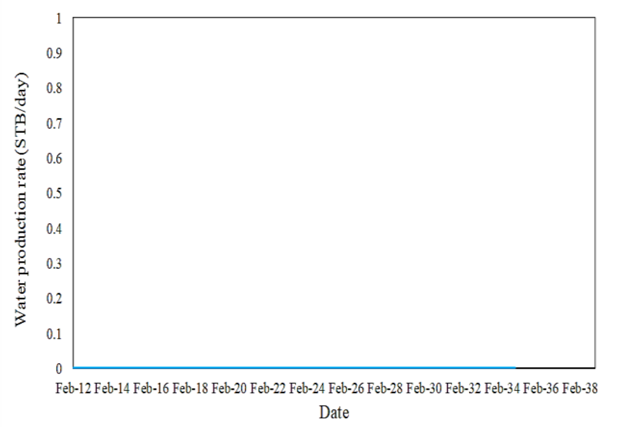

Fig17. Water production

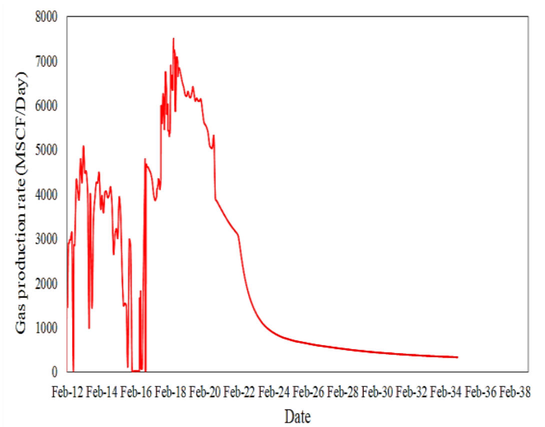

Fig18. Gas production

In Hosseinieh well, the amount of gas in its maximum amount reaches 7000MSCF / day and in the lowest amount of self-contained gas reaches less than 1000MCSF / day. The amount of water in Hosseinieh well reaches zero (0). InThere are both pressures at the bottom and on top of well in Hosseinieh well

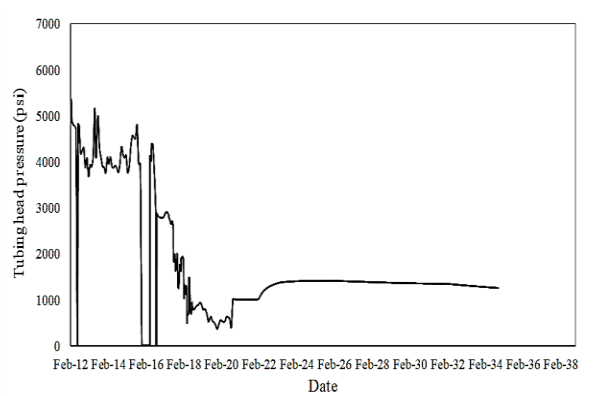

Fig19. Well pressure

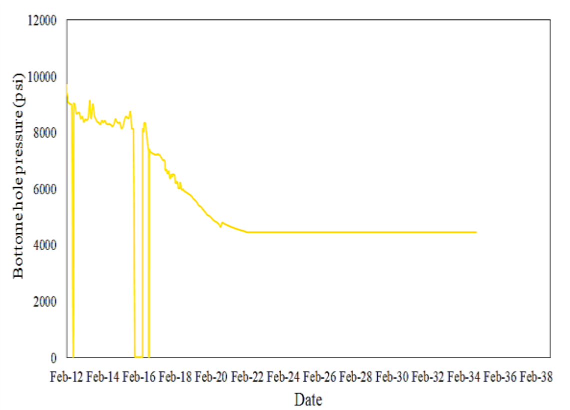

Fig20. Pressure to the well

The graph of the discharge of oil production features out that the reservoir can produce oil with a stable discharge at present conditions.

In Hosseinieh well, the pressure at the bottom of the well reaches to its highest amount which is 8000psi and its lowest pressure at the bottom of the well is more than 4000psi.

The highest pressure at the top of Hosseinieh well is 5000psi and its lowest pressure is 1000psi.

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

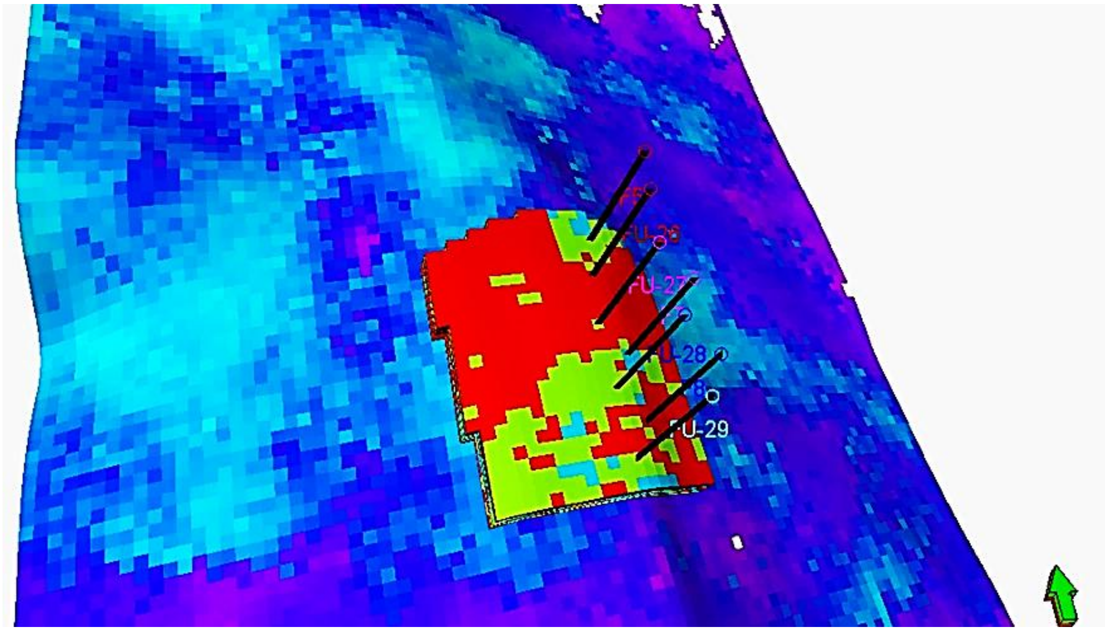

Fig21.The over view of the drilling route of future wells

Flow chart of oil production shows that the reservoir in the current situation is able to produce oil with a constant flow in well number 5-well number 7-well number 8-well and Hosseinieh well. In Hosseinieh well, the pressure at the bottom of the well reaches to its highest amount which is 8000psi and its lowest pressure at the bottom of the well is more than 4000psi. From the twenty-second day onwards, the pressure at the bottom of the well reaches zero (0).

In well number 5, the well pressure value reaches more than 5000psi at its maximum and less than 1000psi at its lowest value. From the twenty-second day onwards, the pressure at the bottom of the well reaches zero (0). In well number 7, oil production at the bottom of the well shows 8000 psi. The minimum value is 4000 psi. Finally, from the twenty-sixth day, it reaches zero (0).

Well pressure in well number 7 reaches 5000 psi at its maximum value, which decreases to its minimum value of 1000 psi during this period. From the twenty-sixth day onwards, well pressure in well number 7 reaches zero (0). It reaches more than 6000psi and its flow rate reaches 7000psi at its maximum. In Hosseinieh well, the cumulative amount reaches 9000STB / day. The flow rate of oil production in Hosseinieh well reaches 6000 STB / day at its maximum and less than 3000 STB / day at its minimum. Lastly, it reaches zero (0). There is water, oil, gas phases in the reservoir of Yadavaran oil field. This reservoir is static and dynamic in three dimensions, for which a segmental model has been studied and investigated.

There is an initial volume of fluid in the tank. There are oil production wells in future wells No. 26-Well No. 27-Well No. 28-Well

No. 29. Water injection wells are also developed for future wells. After simulating the reservoir model for 794 days: water, oil, gas phases are present in the reservoir of the oil field.

conclusion

1-According to the graphs of the discharge of oil production and the ratio of gas to oil, it is concluded that gas interruption occurs. After gas decomposition, the gas to oil ratio increases sharply until the slope of the gas to oil ratio increases slightly due to the decrease in oil production flow.

2- After breaking the gas in the production well, the profit from the increase in oil production should be measured and compared to the costs related to gas injection, such as the cost of gas separation, the cost of equipment, etc. In case of inefficient gas injection efficiency, the injection plan should be stopped and an alternative method should be implemented.

3-The trend of changes in reservoir pressure, production well bottom pressure, and injection well pressure is displayed.

4-The discharge of oil production of vertical wells is getting declined. In other words, the discharge of oil is more than vertical wells for the sake of using horizontal wells.

5-The graph of the ratio of gas to oil divulges that as the discharge of oil production is enhanced, the production amount gets more than the primary amount. However, the reduction of oil production can subject to return the ratio of gas to oil to its primary amount.

References

1. Grayson, C.J (1960), Decisions under uncertainty: Drilling Decisions by Oil and Gas Operators. Harvard U. Pr., p. 402.
2. K. Aziz, A. Settari(1979) “Petroleum Reservoir Simulation”. Applied Science Publishers Ltd., London.
3. Hefner, J.M., Thompsom, R.S(1996), "A comparison of probabilistic and deterministic reserve estimates" : A case study, SPE RE, Feb, p. 43-47
4. Samson, P., DUBRULE, O., EULER, N(1996), Quantifying the impact of structural uncertainties on gross-rock volume estimates, SPE 35535, presented at Europ. 3D Res. Mod. Conf., Stavanger, 16-17 April.
5. Koppe, j. F. 1998. Assessing uncertainty associated with the delineation of geochemical anomalies. Natural resources research.
6. Berteig, V., Halvorsen, K.B., Omre,(1988) H., Prediction of hydrocarbon pore volume with uncertainties, SPE 18325, presented at SPE Ann. Tech. Conf. & Ex., Houston, 2- 5 Oct.
7. Wagner, J., Shamir, U., and Nemati, H. (1992) Ground water quality management under uncertainty: stochastic programming approaches and the value of information. Water Resources Research, 28(5):1233-1246
8. Edwards, R. A. (1994) “Production Prediction Uncertainty and Its Impact on the Management of Oil and Gas price Risk”, Thesis for Degree of Engineering, Department of

PetroleumEngineering, Stanford University, CA.

9. Hefner, J.M., Thompsom, R.S(1996) "A comparison of probabilistic and deterministic reserve estimates" : A case study, SPE RE, Feb, p. 43-47
10. Kruijsdijk, C.P.J.W. VAN(1996) Uncertainty analysis of reserve estimates, SPE 35593, presented at SPE Gas Technology Conf., Calgary, 28 April - 1 May.
11. Lia, O., Omre, H., Tjelmeland, H., Holden, L., Egeland, T(1997) Uncertainties in reservoir production forecasts, AAPG Bulletin, 81, no 5, May, p 775-802.
12. Lepine, O. J., Bissell, R. C., Aanonsen, S. I., Pallister, I. and W Barker,J(1998) "Uncertainty Analysis in Predictive Reservoir Simulation Using Gradient Information," SPE 48997, proceedings of the SPE Annual Meeting, New Orleans (September).
13. Koppe, j. F(1998)Assessing uncertainty associated with the delineation of geochemical anomalies. Natural resources research,
14. Chiles, J.P. and Delfiner, P (1999)Geostatistics: modeling spatial uncertainty. Wiley & Sons, New York.
15. Yamamoto, j. K (march 1999) Quantification of uncertainty in ore-reserve estimation:. Natural resources research
16. Chorn, L.G. & M. Croft (2000) “Resolving Reservoir Uncertainty to Create Value,” Journal of Petroleum Technology, August 2000, pp.52-59.
17. uncertainty in common hydrocarbon indicators. Geophysics 63(6), 1997-2008.
18. Chorn, L.G. & M. Croft (2000) “Resolving Reservoir Uncertainty to Create Value,” Journal of Petroleum Technology, August 2000, pp.52-59.
19. Steagall, D. E. and Schiozer, D. J. (2001) “Uncertainty Analysis in Reservoir Production Forecasts
20. Cortazar, G. & E.S. Schwartz & J. Casassus (2001) “Optimal Exploration Investments under Price and Geological-Technical Uncertainty: A Real Options Model", R&D Management,Vol.31, No. 2, pp. 181
21. Barker, J. W., M. Cuypers, and L. Holden.(2001) “Quantifying Uncertainty in Production Forecasts: Another Look at the PUNQ-S3 Problem.” SPEJ 6 (4): 433–441.
22. F. Friedmann, A. Chawathe, D. Larue (2001) “Uncertainty Assessment of Reservoir Performance Using Experimental Designs”, presented at the Petroleum Society’s Canadian International Petroleum Conference, Calgary, Alberta, Canada, June 12- 14.
23. Mukerji, T., Avseth, P., Mavko, G., Takahashi, I., and Gonzalez, E (2001), Statistical rock physics; combining rock physics, information theory, and geostatistics to reduce uncertainty in seismic reservoir characterization, The Leading Edge, 20, 313-319.
24. R.W. Schulze-Reigert, J.K. Axmann, et at(2001) “Evolutionary Algorithms Applied to History Matching of

JOURNAL OF ALGEBRAIC STATISTICS
Volume 13, No. 1, 2022, p. 339-352
https://publishoa.com
ISSN: 1309-3452

Complex Reservoirs”. SPE Reservoir Simulation Symposium, Houston, Texas, U.S.A., February 11-14.

25. Guyaguler, B. (2002) “Optimization of Well Placement and Assessment of Uncertainty”, PhD
26. Begg, S., Bratvold, R. and Campbell, J. (2002) “The Value of Flexibility in Managing Uncertainty in Oil and Gas Investments,” SPE 77586, SPE Annual Technical Conference and Exhibition, Sept. 29 – Oct. 2, San Antonio, Texas. Society of Petroleum Engineers
27. Da Cruz, P. S. (2002) “Reservoir Management Decision-Making in The Present of Geological
28. Papritz, r. A. (may 2002). An empirical comparison of kriging methods for nonlinear spatial point prediction. Mathematical geology .
29. Zhang, F., A. C. Reynolds, and D. S. Oliver, (2002). Evaluation of the reduction in uncertainty obtained by conditioning a 3D stochastic channel to multi well pressure data, Mathematical Geology, 34(6), 715–742,.
30. Abou-kassem, J.H., S. M. Farouq Ali, M. E. Osman(2006) "The enginnering Approach Versus the mathematical approach in developing reservoir simulations" , journal of Nature Science and Technotogy .
31. Abou-kassem, J.H., T. Ertekin and P. M. Lutchmansingh(1991) "Three Dimentional Modelling of One-English of Confined Five and Nine Spot Patterns", Journal of Petroleum Science and Engineering ,Volume 5.
32. Abou-kassem (1981) J.H. Investigation of Grid Orientation in Two Dimentional , Compositional, and Three phases Steam Model, Ph.D. diss., University of Calgary, Alberta.
33. I. C. Tang(1969) " A Simple Algorithm for Solving Linear Equation of a Certain Type " , Journal of Applied Mathematics and Mechanics , Volume 8.
34. J.D. Hoffman(1992) Numerical Methods for Engineering and Scientists ,Taylor and Franci.
35. K.Aziz(1993) "Reservoir Simulation Grids: Opportunitities and problems " , Spe 25233.
36. K. Azizand(1979) A . Settari . Petroleum Reservoir Simulation , Appled Sciene Publishers.
37. O.A. Pedrosa and K. Aziz(1986) Use of Hybrid Grid in Reservoir Simulation, Standford University.
38. Schlumberger Simulation Software Manuals(2007) Reference Manual E-book.
39. S.M Farouq Ali and J. H. Abou-kassem(2006) Petroleum, Reservoir Simulation a Basic Approach , Houston, TX.
40. S. M. Farouq Ali(1986) Elements of reservoir Modelling and Selected Papaers, Course Notes.
41. T. Ertekin, J. H. Abou –kassem and G. R. King(2001) 'Basic Applied Reservoir Simulation" ,SPE text book , Volume 10.