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ORIGINAL PAPER - PRODUCTION ENGINEERING

The feasibility analysis of underground gas storage during an integration of improved condensate recovery processes

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Abstract

Due to the increasing demand for gas consumption during cold seasons, it is a sense of urgency to provide a reliable resource for gas supply during these periods. The objectives of this comprehensive research entail reservoir core analysis, reservoir fluid study, investigation and optimization of improved condensate recovery during gas storage processes in one of Iranian-depleted fractured gas condensate reservoir. We have attempted to make a balance among reservoir petrophysical and operational characteristics such as production rate, ultimate reservoir pressure after production, cumulative condensate production, number of wells and the required time periods for the reservoir depletion, to obtain an optimum condition for the gas storage process. It's a foregone conclusion that the quality of management decision-making regarding reservoir depletion, maximum gas recovery and natural gas condensate production subsequently optimize at the minimum pressure drop. Furthermore, according to the simulation analysis, pipeline gas injection may lead to condensate recovery improvement.

Keywords Improved condensate recovery · Underground gas storage · Depleted gas reservoirs · Simulation analysis · Gas recovery

List of symbols

B_g	Gas formation volume factor
K	Permeability (mD)
K_r	Relative permeability
K_{rg}	Gas relative permeability
K_{rw}	Water relative permeability
M	Molecular mass (lb/lb mol)
P	Pressure (psia)
Pc	Capillary pressure
S_g	Gas saturation (%)
S_{gc}	Critical gas saturation (%)
S_w	Water saturation (%)
S_{wc}	Connate water saturation (%)
t	Time (day)
T	Temperature (°C)
Z	Compressibility factor

Greek letters

ρ	Mass density (kg/ft^3)
σ	Surface tension (N/m)
φ	Porosity (%)

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Abbreviations

FGPR	Field gas production rate (MMSCF^3/day)
FGPT	Field gas production total (MMSCF^3)
FOPR	Field oil production rate (MMSCF^3/day)
FOPT	Field oil production total (MMSCF^3)
FPR	Field pressure rate (psia)
FWPT	Field water production total (MMSCF^3)
UGS	Underground gas storage
PR	Peng–Robinson
PVT	Pressure volume temperature
ROV	Relative oil volume
CCE	Constant composition expansion
CVD	Constant volume depletion
EOS	Equation of state
I/W	Injection/withdrawal

Introduction

Natural gas is of non-renewable energy resources which are continuously produced and supplied to the market (Farahani et al. 2015). This significant energy resource is referred to as a good strategy for many industries and factories so that consumers try to provide storage facilities and equipment to protect themselves against possible fluctuations and crisis arisen from natural gas shortages (Alim and Tohidi 2012).

The first successful natural gas storage project was implemented in Canada in 1915; however, by 1995, the number of underground gas storage reservoirs increased to 554 reservoirs worldwide, of which 400 reservoirs were located within Canada and US borders (Flanigan 1995). Underground natural gas storage can be defined as storing a mass volume of natural gas within porous media of rocks at different depths (Wang and Economides 2012). Before planning for a storage project, it is of vital importance to investigate reservoir capacity and deliverability, knowledge of market demand and also consider impacts of weather conditions on the gas market (Confort and Jorge 2014). Gas storage is the operation of gas transmission from a reservoir to another reservoir which is close to the target market, to avoid burning and other losses incurred from a drop-in consumption demand (Azin et al. 2008). One of the common methods of natural gas storage, due to consumption supplement in cold season, referred to gas storage in one depleted gas condensate reservoir (Arfaee and Iman 2014). Among other features of depleted gas reservoirs is that they can accommodate an easy and low-cost gas storage operation, because they enjoy appropriate porosity and permeability characteristics (Kuncir et al. 2003). Also, geological structure and petrophysical properties of many gas reservoirs are thoroughly investigated and well specified, so that one can employ computer models developed in the oil and gas industries to predict thermodynamic behaviors, movements and trapping of hydrocarbons (Katz et al. 1959). Furthermore, some of existing facilities and wells can be utilized for storage operations (Knepper 1997). Besides the mentioned reasons, the gas injection can act to recover several percents of the remaining hydrocarbon in the reservoir, so that a gas storage project can also be seen as an enhanced gas and condensate recovery project (Aminian et al. 2007). As such, these reservoirs may provide the best and the most economical accommodations for gas storage (Bennion et al. 2000; Rabbani et al. 2018). The annual number of injections and withdrawals is normally low with the daily transmission rate depending on the porosity and permeability values (Ahmed et al. 1998). Gas injection into depleted gas condensate reservoirs not only stabilizes the reservoir pressure but also leads within-reservoir condensates to be evaporated. As a result, the produced gas via recovery cycles will contain heavy hydrocarbons which are necessary to be separated from the produced gas in the processing units so as not to witness gas condensation thus forming a liquid phase in the pipeline (Katz et al. 1983). The composition of the produced gas from a depleted gas condensate reservoir is different from that of the injected gas, because of the existence of gas condensates within the reservoir in the course of depletion process (Adib et al. 2014; Davarpanah et al. 2017, 2018). In the case where there are some gas condensates in the reservoir due to retrograde condensation phenomenon, the secondary purpose to be followed alongside gas storage process is to produce condensates above via evaporating and then depleting or displacing them (Carriere et al. 1985). Gas storage operation design depends on the reservoir location and performance (Barker and Germer 2010). Those decisions made for the sake of enhanced volume of working gas and deliverability, determining new wells to be drilled and, possibly, specifying some of wells to be abandoned, must be based on an analysis of the circumstances coupled with an accurate simulation of reservoir behavior, so that one can determine the manner in which the operation and corresponding investment should be realized (Masanori et al. 2000). Failure to consider these parameters, there would be a high risk of gas leakage and operation failure. Such a leakage can stem from various reasons such as gas migration, gas trapping in non-accessible regions of the reservoir, and fingering phenomenon of the displacing phase (gas phase) (Mogbo 2011). Furthermore, availability of full history of the field with its initial development details (provided the reservoir under consideration have been originally a gas reservoir) strongly contributes to the successful management of a gas storage operation. Total gas to be addressed in a gas storage reservoir can be divided into two categories. Cushion gas or base gas, which, remaining unchanged within the reservoir, participate in neither injection nor production operations. It only provides the required pressure for the gas to be produced. Cushion gas is either originally in the reservoir or introduced into the reservoir via the first injection phase and will remain in the reservoir until the very end of the reservoir lifetime. Working gas, which is, one or more than one times a year, injected into and withdrawn from the reservoir (Kanaga et al. 2004; Davarpanah and Nassabeh 2017a, b).

Although there are numerous studies being widely reported in the literature about the considerable influence of underground gas storage reservoirs in the condensate enhanced oil recovery, in this comprehensive study, we have concentrated on the management of the depletion phase of the gas condensate reservoirs field, making a balance among reservoir petrophysical and operational characteristics and, pipeline gas injection may lead to condensate recovery improvement.

Field description

Reservoir location and its characteristics

The gas field is located in the northern part of Zagros folding in the west of Iran. It has extended over an area of 125 km^2. The initial reservoir pressure and temperature at the datum depth of 1767.8 m (below sea level) have been 392.9 bar and 103 °C, respectively. Reported for this field is a gas of dew point pressure of 383.4 bar. So that the reservoir's initial pressure is about 9.5 bar above the dew point pressure of the gas. The cores provide a relatively complete coverage of this formation and have served as primary sources of data for rock and reservoir parameters calculation in the course of log analysis. Furthermore, the fracture pressure of the reservoir is about 280 bar according to the well dataset and the injection pressure is estimated approximately 250 bar by a relative safety factor. To calculate lithological volume and porosity, data from petrophysical logs are to be calibrated using available core data along with information obtained from drilling cuts. Core data from the wells located within the field under study was accurately used in the course of this study. Finally, core data were employed to help to predict and to verify lithology and rock types. For a carbonate reservoir, reservoir quality is a result of digenesis history and stratigraphic setting of formations. Average reservoir parameters are calculated based on the application of geological layering. It is worth mentioning that lithological predictions may not independently serve for porosity system description; other methods should be utilized to achieve such a purpose. Multi-core analyses provide us with rock-type prediction and verification, i.e., using associations between lithology and reservoir parameters corrected based on well data one can find a correlation between rock type and lithological faces. Rock-type determination is aimed at using a statistical approach to build a better geological model well-fitted to reservoir variables.

The comprehensive lithological study of this member performed by the use of drilling cores. It has identified four rock types of distinct properties in terms of porosity, water saturation and sound propagation; these rock types are dark-to-light limestone (90–100% limestone), Argillaceous limestone or shale-limestone (70–80% limestone, 20–30% shale), Limy shale or marl (40–50% limestone, 50–60% shale) and Shale (about 80% of shale). To determine various rock types, porosity frequency plots were drawn using porosity data from the petrophysical evaluation of two wells (No. 3 and No. 8). Reservoir rock was divided into four different types that means: $3.5 < \varphi\% < 5.0$, $5.0 < \varphi\% < 10.0$, $10.0 < \varphi\% < 15.0$ and $15.0 < \varphi\% < 20.0$. The static model of the field along with the location of existing wells is clearly depicted in Fig. 1.

Petrophysical characteristics of the reservoir

Based on core data analysis along with the interpretation of micro-laterolog-caliper, laterolog-gamma ray-neutron, and sonic logs, mean effective porosity of net pay was calculated to be 8.3%. Porosity variations strongly followed the variations in the net pay thickness within the member. In other words, porosity increased in an east–west direction with a minimum value of 4.5% and a maximum value of 13%. However, the mean porosity was found to be 8.7%. Permeability data from core samples recovered from two wells within the field indicated a permeability of less than one mD; furthermore, data obtained from the 41-m-long core retrieved from well No. 5 as well as 78 m long one from well No. 6 confirmed the permeability to be less than one mD. Note to the contributions of fractures, particularly those occurred within the upper 183 m of the reservoir into strongly enhanced effective permeability which promotes gas flow. Table 1 represents a brief set of some of the petrophysical characteristics of the reservoir.

To obtain relative permeability, we began with the normalization of laboratory gas saturation data via the following formulae. Then, the normalized saturations were de-normalized based on mean saturation for each group (Craft and Hawkins 1991).

$$S_{gn} = \frac{\left(S_g - S_{gc}\right)}{\left(1 - S_{gc} - S_{wc}\right)} \tag{1}$$

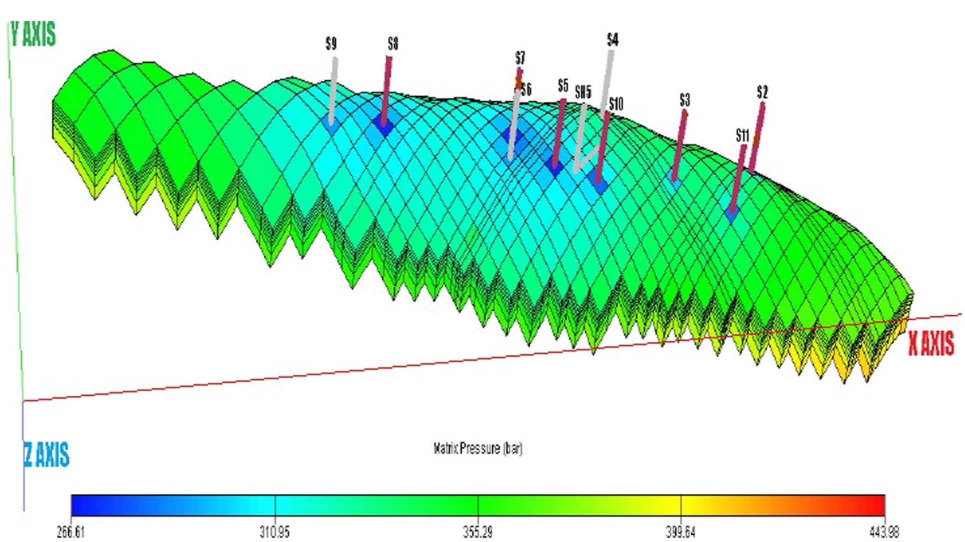

Fig. 1 Static model of the field along with the location of existing wells

Table 1 Petrophysical characteristics of the reservoir

Rock type	Interval		Ave. S_w (%)	Ave. porosity (%)	Permeability (mD)
	Porosity (%)	Saturation (%)			
1	$3.6>\varphi>5.0$	$30>S_w>50$	40.673	4.280	0.199
2	$3.6>\varphi>5.0$	$50>S_w>77$	62.865	4.280	0.063
3	$5.0>\varphi>10.0$	$25>S_w>50$	39.503	6.818	0.068
4	$5.0>\varphi>10.0$	$50>S_w>77$	62.865	6.818	0.068
5	$10.0>\varphi>16.0$	$30>S_w>57$	45.240	11.809	1.857

$$K_{rg_n} = \frac{K_{rg}}{\left(K_{rg}\right)_{S_{wc}}} \tag{2}$$

$$K_{rw_n} = \frac{K_{rw}}{\left(K_{rw}\right)_{S_{gc}}} \tag{3}$$

where S_g, S_{gc} and S_{wc} are reported gas saturation, critical gas saturation and connate water saturation, respectively.

Simulation procedures

Equation of state

Knowing that the behavior of a gas condensate reservoir is strongly dependent on the fluid composition, it is vitally necessary to predict reservoir fluid composition variations under various pressures in the course of depletion process. To determine reservoir fluid characteristics, it is necessary to perform a phase behavior study on the reservoir fluid under reservoir as well as surface conditions. Typically, when gas condensate reservoirs are concerned, one may conduct CVD and CCE tests. Constant volume depletion (CVD) and constant composition expansion (CCE) tests have been performed on well site fluid samples recovered in 1959 with the results presented in Tables 2 and 3. Table 4 indicates reservoir fluid composition. Reservoir fluid is reported to have a molecular mass of 24.6 kg/kg mol and a saturation pressure at a dew point of 383.4 bar so that considering the initial reservoir pressure of 392.9 bar; one can conclude that the primary reservoir fluid has been solely in the gas phase. Knowing that the reservoir temperature is 108.8 °C, while the fluid's cricondentherm temperature is 177.2 °C which is even higher than its critical temperature, one may suggest that this reservoir is a gas condensate reservoir. The value of the condensate-gas ratio (CGR) for this reservoir is 300.380 M^3/$MMSM^3$ which further confirms the idea. PVTi module of ECLIPSE software package (by ECLIPSE

Table 2 Results of CCE test on the reservoir fluid sample

Row	Pressure (bar)	Relative oil volume (ROV)	Gas Z-factor
1	6414.700	0.898	1.014
2	5699.000	0.976	0.980
3	5661.716	1.000	0.970
4	5490.200	1.004	0.970
5	5419.100	1.015	0.968
6	4850.200	1.116	0.951
7	4423.500	1.210	0.941
8	3996.800	1.327	0.933
9	3570.000	1.474	0.928
10	3318.300	1.581	0.926
11	3143.300	1.665	0.926
12	2716.600	1.921	0.925
13	2290.000	2.278	0.928
14	1863.200	2.809	0.933
15	1436.500	3.670	0.942
16	881.800	6.073	0.959

Table 3 CVD test on the reservoir fluid sample

Row	Pressure (bar)	ROV	Liquid density (kg/m^3)	Gas Z-factor	Liquid sat.
1	5561.300	0.046	33.667	0.973	0.000
2	5134.600	0.048	35.920	0.959	0.026
3	4494.600	0.055	36.817	0.942	0.048
4	3996.900	0.058	37.645	0.933	0.055
5	3498.900	0.059	38.430	0.928	0.058
6	3001.100	0.058	39.197	0.925	0.059
7	2503.300	0.056	39.966	0.926	0.058
8	2005.500	0.054	40.761	0.931	0.056
9	1507.700	0.050	41.606	0.940	0.054
10	1009.900	0.046	42.466	0.953	0.050
11	554.700	0.032	43.826	0.969	0.046
12	14.700	0.031	43.921	0.998	0.032

Table 4 Fluid sample composition, reservoir fluid grouping to the 9 components and decomposition of heavy components into three pseudo-components with the help of exponential distribution function

Fluid sample composition		Reservoir fluid grouping		Decomposition of heavy components	
Component	Mole (%)	Component	Mole (%)	Component	Mole (%)
N_2	2.104	N_2	2.104	N_2	2.104
CO_2	0.179	CO_2	0.179	CO_2	0.179
C_1	82.174	C_1	82.174	C_1	82.174
C_2	6.308	C_2	6.308	C_2	6.308
C_3	3.438	C_3	3.438	C_3	3.438
iC_4	0.536	PS_1	2.738	iC_4	0.536
nC_4	1.309			nC_4	1.309
iC_5	0.439			iC_5	0.439
nC_5	0.454			nC_5	0.454
C_6	0.587	C_6	0.587	C_6	0.587
C_{7+}	2.472	PS_2	0.871	C_{7-10}	1.472
		PS_3	0.600	C_{11-14}	0.596
				C_{15+}	0.405

300 with the trial license 78843C358D12, 2015.1) was utilized to set up a specific equation of state for this reservoir. The results of CCE and CVD test depict statistically in Tables 2 and 3. The heaviest component in the fluid composition was reported to be C_{7+}. Based on the molecular mass and specific density of this heavy component, Watson characterization factor was determined for C_{7+} via the following equation (Danesh 1998):

$$k_w = 4.5579\, M^{0.15178}\, S^{-0.84573} \tag{4}$$

where k_w, M, and S are Watson characterization factor, the molecular mass of C_{7+}, and specific density of C_{7+}, respectively.

Peng–Robinson equation of state was chosen for investigation of reservoir fluid phase behavior. To enhance flexibility of the equation of state, an exponential distribution function was utilized to decompose heavy component of C_{7+} into three virtual components. Furthermore, Jossi–Stief–Thodos empirical formulae was implemented to compute the value of viscosity under the reservoir conditions, while Yoon–Thodos–Herning empirical correlation was utilized for lower pressures (Graboski and Daubert 1978). Since this is a gas condensate reservoir, a mixed model should be employed to simulate it. Due to exhaustive calculations involved in this type of model, there is a need to reduce the number of fluid elements as much as possible, so reservoir fluid elements were lumped before configuration of the equation of state, and the previous equation of state is reconfigured for a 9-element fluid in Table 4. Furthermore, Table 4 indicates the decomposition of heavy components into three pseudo-elements with the help of exponential distribution function.

Regression calculus was used to configure the equation of state. For this purpose, critical pressure and temperature, and acentric factor were declared as the regression variables. To achieve the best results regarding the equation of state, various weighting factors were considered for the results of CCE and CVD tests as well as saturation pressure (Pedersen et al. 1992). Adjusting regression parameters, the best agreement was achieved between experimental data and the results of the equations of state. Figures 2 and 3 indicate the obtained results. Furthermore, calculation error for the dew point pressure was measured to be 0.001.

History matching

Started at the March 1, 1959, field gas production rate has been initially 5800 m^3/day; however, it has increased to 10200 m^3/day by the end of that year. The presented history

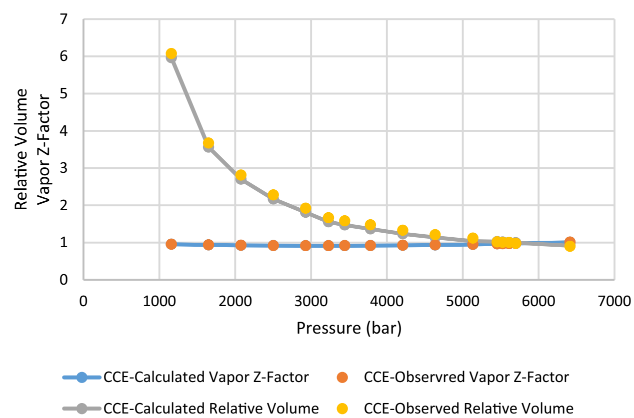

Fig. 2 CCE relative volume and vapor Z-factor results under laboratory conditions (108.8 °C)

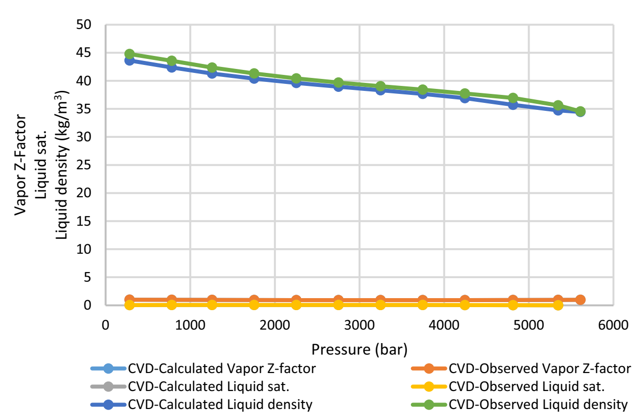

Fig. 3 CVD vapor Z-factor, liquid density and liquid saturation results under laboratory conditions (108.8 °C)

and available data suggest gas expansion to be the primary production drive. Constant volume depletion of gas condensate reservoir has been accompanied by retrograde condensation phenomenon. To investigate the surface efficiency of the condensates and obtain the composition and volume of the retrograding fluid within the reservoir, one may need to perform phase behavior calculations within an early production period. For this purpose, the initial production history of the reservoir should be modeled by the simulator using available data and the results of data analyses. In the next step, one can obtain the reservoir fluid composition using phase behavior studies. If an acceptable match was obtained between the history and initial production data, the developed model could be reliably used to predict the recoverable gas in the course of the gas storage operation. Furthermore, a recovery cycle can be simulated to be able to predict the efficiency of the produced condensates. In this research, a complete reservoir production history matching is performed using the simulator under consideration indicating a similar production behavior of simulator to that of the real reservoir. Field gas production rate, field oil production rate and field pressure rate under history matching are shown in Fig. 4.

Result and discussion

For a gas condensate reservoir to be a candidate for gas storage, not only a maximized gas recovery factor has to be already realized, but also heavy and valuable components in the reservoir should be recovered as much as possible which is among the most critical objectives in the course of this study. Once the production rate exceeds an allowed threshold, a drastic pressure drop will occur within an area around the wellbore which results in the liquefaction of heavy compounds making them remained in this area. In such a case, in addition to the loss of these valuable compounds, reservoir rock diffusivity respect to gas phase will dramatically decrease leading to a significant drop-in gas production rate (Gerov and Lyomov 2002). Also, in this research, we have tried to provide the best conditions for the gas storage process while considering some adequate natural depletion scenarios. Under such conditions, it is very important to select a proper pressure at which to terminate the production operation and start gas storage process. Besides, a number of wells should be optimally set based on the simulation results. For a given production rate, the higher number of wells drilled, the lower per well pressure drop will result so that the volume of recovered condensate until reaching an ultimate pressure will increase.

Reservoir natural depletion

Reservoir fluids are multi-component mixtures of main hydrocarbons such as paraffin, naphthenic and aromatic with non-hydrocarbon traces such as water, nitrogen, carbon dioxide and hydrogen sulfide. There are two approaches in simulating reservoir and well fluid behavior; Black Oil and Compositional Model. In this comprehensive study, we use compositional model in the simulation processes. Compositional Model Approach Properties;

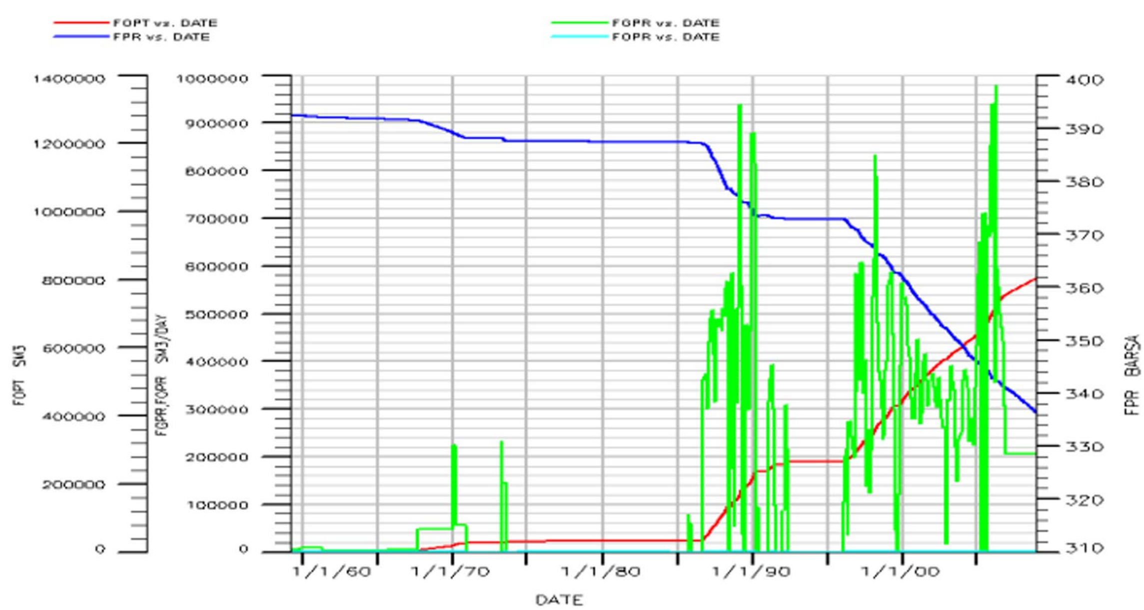

Fig. 4 Field gas production rate, field oil production rate and field pressure rate under history matching

- It is suitable for volatile oils with high GORs.
- It is used with significant compositional variations in a reservoir as pressure is depleted.
- Influence of individual components on the composition of the mixture is essential.
- It is used *N* components (up to 20) based on paraffin series.
- This needs EOS-based calculations.
- It needs a feed-forward calculation of fluid properties (Vapor and Liquid equilibrium required).
- Typically, we cannot account for all hydrocarbon components, so we lump components with similar thermodynamic properties plus water and possibly carbon dioxide.
- This is needed where the gas/oil may become miscible.

Considering numerous production scenarios, we have attempted to make a balance over such parameters as production rate, post-production ultimate reservoir pressure, the cumulative amount of condensates produced, number of wells and number of days required for reservoir depletion using compositional simulator of ECLIPSE software package, so that an optimum case can be achieved.

- In scenario 1, setting higher production rates (higher than the optimum value for each well which is 2 MMSM^3/D) for the four wells, it is observed, as expected, that after a short time, an intensive per well pressure drop is realized which is shortly followed by water conning phenomenon leading to a significant increase in the produced water–gas ratio (Molinard et al. 1990). Accordingly, cumulative gas and condensate production will be minimized. Under such conditions, the production will rapidly down rate and finally terminated without achieving the expected gas and gas condensate recovery factors. In other scenarios, due to these observations, lower production rates are maintained from these wells.
- In the next scenarios, we have tried to drill four new wells within the reservoir top area and also to change gas recovery rate from each well to obtain the best reservoir depletion plan. In scenario 2, the minimum production rate has been set. The obtained results of this case indicate a slight pressure drop even a very long time after starting the production (ultimate reservoir life, i.e., 21,000 days), so that the injection operation should be triggered at a very high pressure which makes the operation economically nonviable even if an adequate set of compressors is available to generate such a pressure. This can be attributed to the reservoir aquifer and suggest a partial aquifer which depends on the production rate from the reservoir. Such an aquifer may only serve to compensate hydrocarbon depletion-derived pressure drop at lower production rates and will lose its effectiveness at higher production rates. Contributions of the number of wells are considered in scenarios 3 and 4. In scenario 3, the reservoir has produced via eight producing wells, whereas in scenario 4, keeping the maximum production to be that in scenario 3, two more producing wells have been drilled causing a reduction in per well production rate. As mentioned before, as per well pressure drop is reduced, reservoir's mean pressure drop is decreased also leading less number of condensates to liquefy in the reservoir environment. Hence, cumulative condensate production enjoys a significant increase. Also, a longer period would pass before a given drop in the production rate occurs, while cumulative gas production is also boosted. Evaluating different scenarios and their results, scenario five was developed in such a way to obtain the best results. In this scenario, in addition, to producing maximum amount of gas and gas condensate, an acceptable per well production rate was achieved.

In sum, it can be suggested that determining an optimum production rate; one may produce maximum gas and gas condensate while providing the required pressure drop for the gas injection operation to be feasible. The results of different scenarios are briefly presented in Table 5. Figures 5, 6 and 7 indicate cumulative production of gas, cumulative

Table 5 Summary implementation scenarios for reservoir natural depletion

Scenario	Individual well productions (MMSM^3/day)	FGPR (MMSM^3/day)	FGPT (MMSM^3)	FOPT (MMSM^3)	Time (day)
1	S2 = 3, S3 = 3, S5 = 3, SH5 = 3	12	2.62	66.93	21,000
2	S2 = 1, S3 = 1, S4 = 1, S5 = 0.5, SH5 = 0.85, S6 = 0.5, S7 = 1, S8 = 1	6.85	3.85	95.1	21,000
3	S2 = 1.25, S3 = 1.25, S4 = 1.25, S5 = 1.25, SH5 = 1.25, S6 = 1.25, S7 = 1.25, S8 = 1.25	10	4.17	102.65	21,000
4	S2 = 1, S3 = 1, S4 = 1, S5 = 0.5, SH5 = 0.85, S6 = 0.5, S7 = 1, S8 = 1, S9 = 1.575, S10 = 1.575	10	4.66	113.26	21,000
5	S2 = 1.25, S3 = 1.75, S4 = 1.75, S5 = 1.75, SH5 = 1.75, S6 = 1.75, S7 = 1.75, S8 = 0.75	12.5	6.37	148.16	21,000

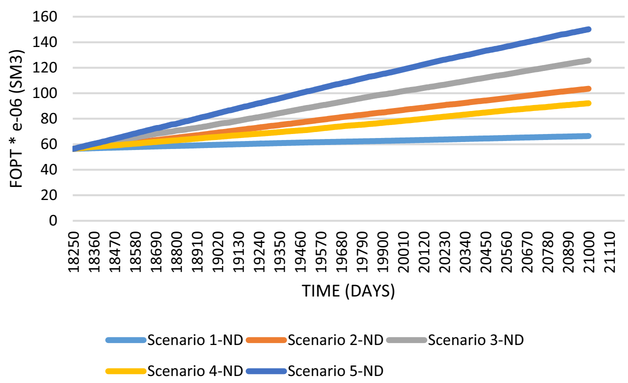

Fig. 5 Cumulative production of gas in five natural depletion scenarios

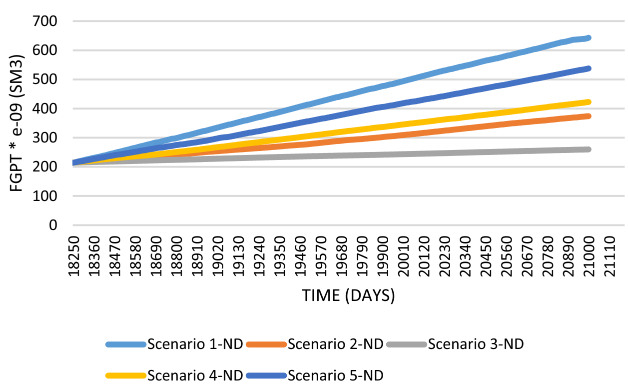

Fig. 6 Cumulative production of gas condensate in five natural depletion scenarios

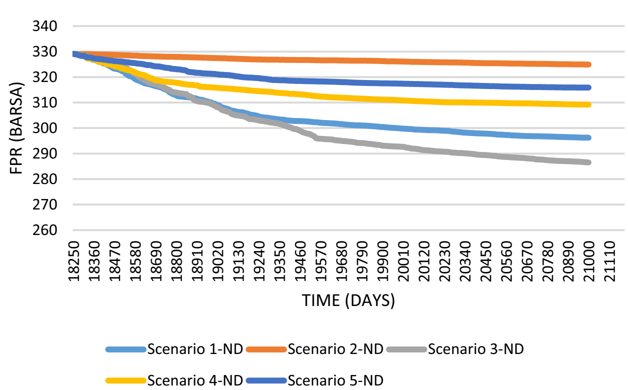

Fig. 7 Field reservoir pressure drop trend in five natural depletion scenarios

production of gas condensate, and reservoir pressure drop trend for scenarios 1–5, respectively.

Determination of gas injection and withdrawal periods

Since the ultimate goal of any gas storage project is to supply market demand during the peak season, it seems necessary to consider gas consumption variations during a typical year to be able to set an optimum production plan (Hollis 1984). On the other hand, since non-industrial gas consumption (environment heating applications) is responsible for significant changes in gas consumption in the cold season, one may consider gas consumption variations in residential, commercial and non-major industries applications as the design pattern for determining gas injection and withdrawal periods (Kenneth et al. 2003). Frequently, March 21st and November 23rd are taken as critical dates of consumption pattern alteration. As such, each year, the injection operation is triggered on March 21st and is stopped by November 23rd (Xiao et al. 2006). Each injection-withdrawal cycle starts with an injection period and ends with a withdrawal one. A particular well stop and the soaking interval are to be considered between two successive injection-withdrawal cycles. Although showing some variations depending on the reservoir dimensions, this well stop and soaking interval is typically something between 15 and 30 days. It is considered to allow a uniform pressure to be established across the entire reservoir (Henderson et al. 1993; Aminian et al. 2006). In this research, a 15-day well stop and soaking interval has been assumed, so that accommodating a 15-day interval between any two successive injection-withdrawal cycles, the withdrawal season is set to start on December 6th and stopped on March 6th.

Underground gas storage

A set of four wells were assumed as injection/withdrawal wells. These are drilled within the reservoir top and enjoy minimum leakage probability. During injection and withdrawal operations, other wells are kept stopped and serve as observation wells. In the beginning, target production rate is set based on per well withdrawal objective for peak season (2 MMSM^3/D). Based on the determined duration of injection and withdrawal operations, injection rate per well is 750 MSM^3/D. Among other scenarios for natural depletion phase of the reservoir, scenario five was selected to begin with the alternating process of gas storage and withdrawal. This scenario was associated with the best results regarding maximum cumulative gas and condensate production and minimum pressure drop. Furthermore, different abandonment reservoir pressures were tested to find the optimum one, to determine the optimum base gas capacity.

Table 6 Reservoir fluid composition under different scenarios

Composition of the reservoir fluid after 21,000 days of scenarios 5		Composition of natural gas flowing into the gas pipeline		Composition of the injected gas according to the composition of the gas pipeline		Rich gas composition for injection into the reservoir	
Component	Mole (%)	Component	Mole (%)	Component	Mole (%)	Component	Mole (%)
N_2	2.070	N_2	3.500	N_2	3.500	N_2	3.500
CO_2	0.430	CO_2	1.000	CO_2	1.000	CO_2	1.000
C_1	78.500	C_1	81.300	C_1	81.300	C_1	77.370
C_2	6.390	C_2	5.500	C_2	5.500	C_2	5.500
C_3	3.510	C_3	3.000	C_3	3.000	C_3	3.000
PS_1	3.010	PS_1	3.000	C_4	0.960	PS_1	3.000
C_6	0.860	C_6	2.690	C_{5+}	4.730	C_6	2.690
C_{7+}	3.310	C_{7+}	0.000			C_{7+}	2.000
C_{17+}	1.900	C_{17+}	0.000	H_2S	3.000 ppm	C_{17+}	2.000

Scenario 5.1

Scenario 5 was assumed for the first storage phase, i.e., 21,000 days after production initiation when reservoir production potential would approach zero (abandonment pressure of 200 bar). Methane of 100% purity was chosen as the injected gas. The composition of reservoir fluid is presented in Table 6. As can be seen, in this scenario, low volume of reservoir cushion gas cannot provide the recovery periods with the specified production rate. As such, scenario 5.2 was developed and executed.

Scenario 5.2

To boost cushion gas volume, scenario five will be held until 21,000 days (applying an abandonment pressure of 250 bar) after when successive injection-withdrawal cycles will start. At this time, average reservoir pressure is predicted to be 250 bar. Five successive cycles of storage process were successfully operated under this scenario leading target production rate to be realized. As mentioned before, working gas volume was assumed to be 720 MMSM^3 for all scenarios investigated. In the next step, to study the contribution of this parameter and perform a sensitivity analysis of the process concerning this parameter, scenario 5.2 was rerun in two stages. Keeping other gas storage operational parameters constant, scenario 5.2 was launched with double working gas volume and also with half working gas volume in the first and second stages, respectively. For both wells, injection and withdrawal rates per well are 1.47 and 0.375 MMSM^3/day, respectively.

In Figs. 6, 7, 8 and 9 a comparison among three scenarios regarding contributions of working gas volume has been illustrated schematically. Since this gas storage operation aimed maximizing the supply of a part of the demanded amount of gas during the peak season has simulated, it will

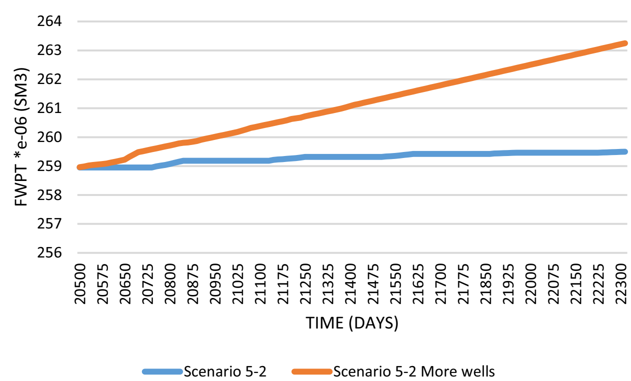

Fig. 8 Field water production rate reduction with increasing number of wells

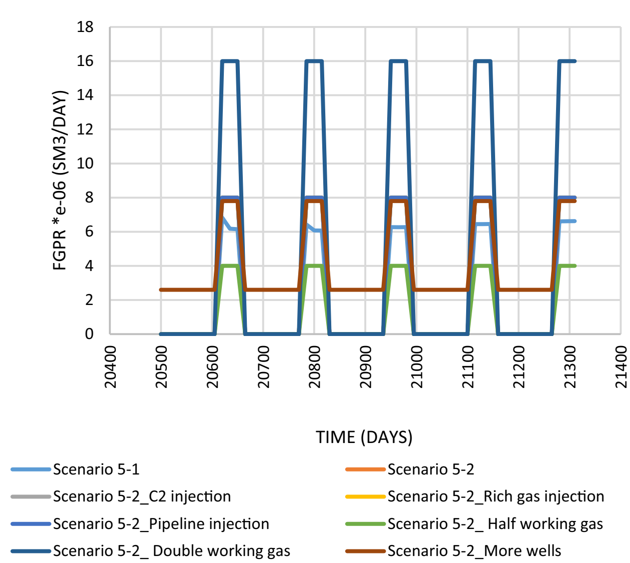

Fig. 9 An increased field gas production rate under different scenarios

be desired to employ maximum working gas volume. On the other hand, once gas production rate exceeds beyond a particular limit, the reservoir can no more provide the planned production rate for the withdrawal season. As can be seen in Fig. 7, doubling working gas volume and producing a sum of 16 MMSM3/day of gas during the cold season, field gas production rate will increase after several successive injection-withdrawal cycles; whereas in the scenario with half working gas volume, field gas production rate will reduce. Up to this point, 100% pure methane was assumed as the injected gas for the investigated scenarios. However, to study the impact of the injected gas composition into gas storage operations, scenario 5.2 will be rerun with changed injected gas.

Pipeline gas injection

Assuming compressors to be directly fed by the nationwide gas pipeline, composition of pipeline gas was considered for the injected gas into the reservoir under the first scenario. Table 6 demonstrates the composition of natural gas flowing inside the gas pipeline. According to this table and knowing that no heavy components exist within the gas fed into the pipeline, the composition of the injected gas is set as shown in Table 6. Obtained curves indicate similar parameters for both scenarios, except for condensate production rate. Pipeline gas injection scenario is associated with a decreased ratio of produced gas to condensate (compared to that in pure methane injection scenario). Knowing that gas production rate is the same for both scenarios, a reduction in the ratio of produced gas to condensate means nothing but an increase in the production rate of condensates, as shown in Figs. 7 and 8.

Increasing the percentage of ethane in the injected gas

To further observe the impact of the presence of ethane in the composition of the injected gas, a gas flow of 80% methane and 20% ethane was chosen to be injected into the reservoir. As can be seen in Fig. 6, the rise of ethane percentage in the injected gas is associated with an increased rate of condensate production (the curve designated as C2 injection). Therefore, the increased condensate production under pipeline gas injection scenario may be attributed to the increased percentage of ethane component in the injected gas. To verify this, keeping the same percentages of other components in the pipeline gas composition, the volume of methane was reduced by 4% while heavy components of C_{7+} and C_{17+} were increased by 2%. In this way, a rich—in heavier compounds—gas flow with the compositions indicated in Table 6 was set as the injected gas to the reservoir to investigate the contributions of such compounds into the gas storage operations. Analyzing the results of this scenario, an increased condensate production rate was observed, particularly after several injection-withdrawal cycles. However, remembering that 4% of heavy compounds already present in the injected gas composition, such an increase in the condensate production rate seems to be relatively insignificant. To sum up, the closer the injected gas composition be to the pipeline gas composition, the higher reservoir condensate recovery factor would be realized.

Impact of the number of wells on the gas storage process

To investigate the contributions of the number of wells into the underground gas storage operation, scenario 5.2 was rerun with to additional wells assumed. Similar to the scenario where the impact of the number of wells on the depletion phase was investigated, here again, other factors were kept unchanged. Accordingly, similar to that in scenario 5.1 (taking a constant working gas volume into account), injection and withdrawal rates per well are 1.3 and 0.5 MMSCF^3/D, respectively. This scenario's results indicate significant contributions of increasing the number of wells at constant working gas volume into the reservoir pressure, amount of condensate in place, and also condensate production rate; it also causes lower water production from wells due to lower wellbore pressure drop and absence of water conning phenomenon (Cullick et al. 1993). Figure 8 indicates field water production rate reduction with increasing

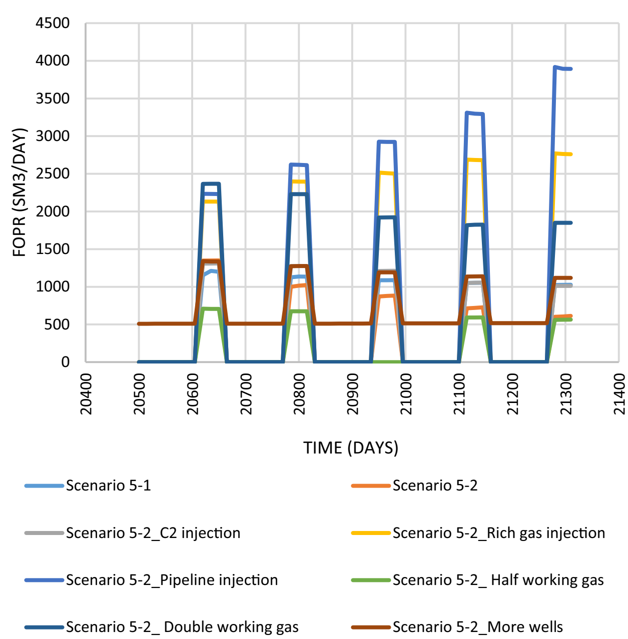

Fig. 10 An increased field condensate production rate under different scenarios

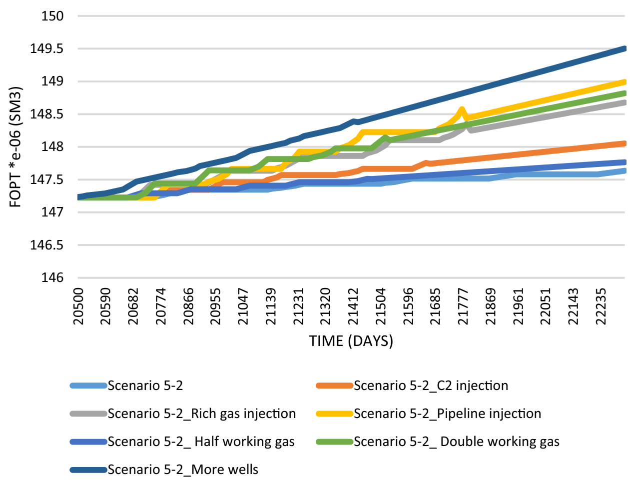

Fig. 11 An increased cumulative condensate production rate under different scenarios

number of wells. However, an increased field gas and condensate production rate, cumulative condensate production rate under different scenarios is graphically demonstrated in Figs. 9, 10 and 11. As is suggested by these figures, the maximum cumulative condensate production can be achieved by increasing the number of wells indicating a significant contribution of this parameter into the field cumulative condensate production.

Conclusions

(1) One of the most critical factors contributing to successful underground gas storage operations in gas condensate reservoirs is how to manage the depletion phase of the field under consideration. Excessive gas production rate during the depletion phase may lead to an increase in the saturation of condensates over an area around the wellbore, so that the reservoir could not provide the sufficient pre-planned production rate during the withdrawal season. Furthermore, the production rate may continue as long as the reservoir cushion gas volume does not fall below a minimum required limit. Failure to meet this requirement may lead to failure to achieve the expected reservoir deliverability by the end of the injection season. In the reservoir depletion phase, one should try to realize the maximum gas and gas condensate recovery at the expense of the minimum pressure drop while maintaining reservoir potentials to be transformed into a gas storage facility.

(2) Determining the optimum volume for working gas not only maximizes the gas and gas condensate productions but also makes the planned production rate for the recovery season practically feasible.

(3) The closer the composition of the injected gas be to the composition of the pipeline gas, the better will be the mixing of the reservoir gas with the injected gas and the higher will be the gas condensate recovery.

(4) Investigating different scenarios, an optimum number of wells should be determined. In this study, four wells were utilized in the course of gas storage operation; however, adding two more wells was associated with significant increase in cumulative gas and gas condensate production rates, as well as a decrease in the field cumulative water production leading to reduced water conning effect in the wells.

(5) Pressure variations in a gas condensate reservoir at a pressure below the dew point pressure are not similar to that of a dry gas reservoir. During the injection interval, due to potential evaporation of condensates around the injecting/producing wells, a faster increase in the field pressure, compared to that in dry gas fields, is likely to occur. On the other hand, failure to realize an adequate production in the course of production interval may lead condensates to be accumulated resulting in an extensive reduction in the field productivity.

(6) According to the investigations, injecting pipeline gas will be followed by an increase in the field condensate production. This is important from two aspects: first, the increased condensate production may contribute to higher profitability. However, considering heavy costs imposed by the presence of condensates (associated costs of separating) in the course of injection-withdrawal cycles, condensate production is more likely to be costly rather than profitable. Detailed economic investigations should be conducted to determine the field profitability in the case where condensate is produced.

(7) Due to continuously changing the composition of the reservoir fluid in the course of gas storage process, there is a need to a powerful compositional simulator which can analyze continuous displacement of condensates, gas, and water within the reservoir.

(8) Gas storage operation can serve as improved condensate recovery operations in gas condensate reservoirs.

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