Optimization of gas condensate Field A development on the basis of "reservoir – gathering facilities system" integrated model

E A Demidova[1] and O V Maksyutina[2]

[1,2] Tomsk Polytechnic University, Tomsk, Russia

E-mail: DemidovaEA@hw.tpu.ru

Abstract. It is known that many gas condensate fields are challenged with liquid loading and condensate banking problems. Therefore, gas production is declining with time. In this paper hydraulic fracturing treatment was considered as a method to improve the productivity of wells and consequently to exclude the factors that lead to production decline. This paper presents the analysis of gas condensate Field A development optimization with the purpose of maintaining constant gas production at the 2013 level for 8 years taking into account mentioned factors . To optimize the development of the filed, an integrated model was created. The integrated model of the field implies constructing the uniform model of the field consisting of the coupling models of the reservoir, wells and surface facilities. This model allowed optimizing each of the elements of the model separately and also taking into account the mutual influence of these elements. Using the integrated model, five development scenarios were analyzed and an optimal scenario was chosen. The NPV of this scenario equals 7,277 mln RUR, cumulative gas production – 12,160.6 mln m^3, cumulative condensate production – 1.8 mln tons.

1. Introduction

Gas-condensate Field A was discovered in 1963 and is located in the west of Tomsk Oblast. The geological cross-section of Field A is represented by sandy-clayey formations of the Mesozoic-Cenozoic sedimentary cover and Paleozoic basement formations. There are two gas-condensate deposits in this field. These deposits are located in the J_1 and J_2 formations.

The gas-condensate deposit of the J_1 formation is a layer-arch deposit. Reservoir rocks are sandstone and siltstone. A cap rock for this deposit is Georgiev and Bazhenov suites, the cumulative thickness of these formations is up to 51 m. The mean value of porosity is 16%, gas saturation – 66%, permeability – 3.5 mD, net gas thickness – 9 m. The gas-condensate deposit of the J_2 formation is a layer-arch deposit too. The deposit was penetrated by a well at the depth of 2,305-2,402 m. Reservoir rocks are medium and fine-grained sandstones covered by clay. The cap rock for the deposit is Nizhnevasyugan suite clay. The mean value of porosity is 16%, gas saturation – 66%, permeability – 3.3 mD, net gas thickness – 6.2 m.

The main development target of the Field A is the J_1 gas-condensate formation. This production horizon is divided into two productive layers, J_1^{1+2}, J_1^{3+4} and one J_1^5 interlayer. The gas water contact is located at -2,245m TVD, it is common of all the productive formations. The general reservoir and fluid properties are presented in Table 1.

Table 1. Reservoir and fluid features

Parameter	Value	
Initial reservoir pressure, atm	246	
Reservoir pressure as of 01.01.2014, atm	Area 1 152	Area 2 205
Dew point pressure, atm	246	
Reservoir temperature, ^{0}C	86	
Permeability, mD	3.5	
Gas viscosity, cP	0.018	
Condensate density , g/m^3	0.76	
Net pay thickness, m	10	
Gas compressibility factor, dimensionless	0.87	
GWC, m (TVD)	-2,245	
GIIP, MM m^3	23,908	
CIIP (geologic/recoverable), M ton	4,662/2,727	
Gas recovery factor as of 01.01.2014	0.24	
Condensate recovery factor as of 01.01.2014	0.207	

The following factors restrict well operations and limit production in Field A:

- accumulation of condensate in the wellbore at smaller gas rates relatively to the base rates (i.e. gas velocity is insufficient to lift the fluid, liquid loading).
- long periods of uncontrolled wells exploitation with reduced gas flow rates due to liquid loading.
- condensation in the reservoir due to reservoir pressure reduction below the dew point pressure resulting in condensate deposition in the near-wellbore area (condensate banking).

Reducing the impact of these factors on field development is a real opportunity to increase the productivity of the wells in the next few years.

2. Gas and condensate production technology of Field A

The gas and condensate Field A was put into production in 2002. As it has already been mentioned, the field has two deposits in the J_1 and J_2 formations. There is one exploration target and all formations are being developed simultaneously. The Field A is developed by depletion drive. Gas injection is not provided in this field. The dew point pressure equals the reservoir pressure of 246 atm. Today, the number of production wells in the field is 22 (figure 1). These wells are located within four clusters (figure 1): five wells in the first cluster, seven wells in the second cluster, six wells in the third cluster and four wells in the fourth cluster. It is planned to drill four new wells in Field A in accordance with the Field A technological development plan. Two wells in the 6th cluster are planned to be drilled at the beginning of 2017 and other wells are planned to be drilled in the 7th cluster at the beginning of 2019 (figure 1, clusters 6, 7).

Hydraulic fracturing treatments were made in wells A21, A23, A25, A27, A42, A43, A44, all of which were successful. The well experienced a 3.5-time increase in productivity on the average.

There are two development areas in Field A: Area 1 developed in clusters 1, 2, 3 and Area 2 developed in cluster 4. Area 2 was put into production only at the end of December 2012. There is no connection between these two areas. Therefore, reservoir pressures were different in 2014: 152 atm in Area 1 and 205 atm in Area 2 (01.01.2014).

The gas gathering pipelines from the clusters are interconnected and the gas condensate fluid is transported to a gas treatment unit located in Field A under its own pressure. The lengths of the gathering pipelines from the clusters to the gas treatment unit are as following:

from the first cluster – 10,435 m;

from the second cluster – 1,980 m;

from the third cluster – 7,280 m;
from the fourth cluster – 7,550 m.

The pipelines from the clusters are made of pipes with OD = 273 mm and wall thickness of14 mm (the first, second and third clusters) and with OD = 219 mm and wall thickness of 12 mm (cluster 4).

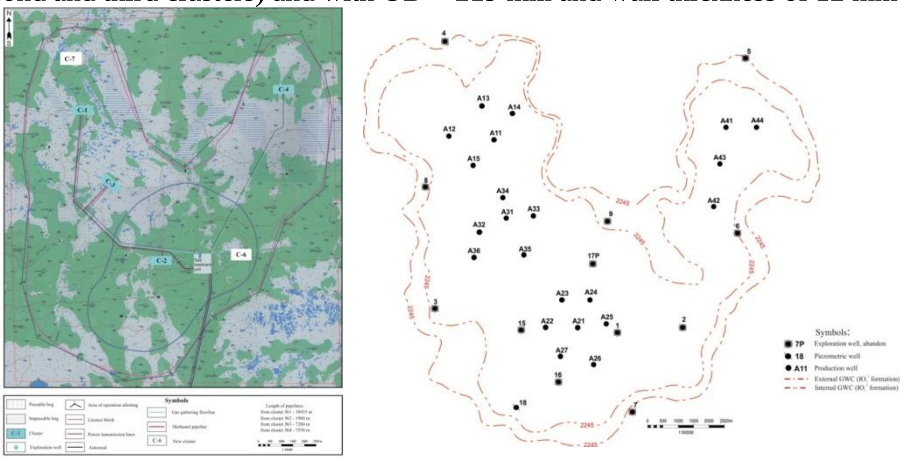

Figure 1. Cluster location layout (left) and well pattern at Field A (right)

3. Factors leading to production decline in Field A

There are two main factors leading to the production decline in Field A and they are liquid loading and condensate banking.

3.2. Liquid loading in Field A

During the development of a gas condensate field, the gas velocity should be high enough to transport liquids to the surface. It is known that gas velocity reduces with time. As a result, the gas velocity can be insufficient to transport condensate to the surface. Therefore, liquid will flow down to the bottomhole. The increase in the percentage of accumulated liquid while a well is flowing can result in a production reduction. A well can also stop if the liquids are not removed continuously [1]. To make an efficient plan and design for tackling the liquid loading problem, it is essential to predict when wells might begin to experience liquid loading [1-3].

First of all, the liquid loading velocity (critical velocity) and critical gas rate were calculated on the basis of the correlations suggested by Turner et al. “Critical velocity” is generally defined as the minimum gas velocity in a well required to move droplets of liquid upwards. In general, except for the critical velocity, the critical gas rate was also calculated. Critical gas rate is the minimum gas rate required to move liquid upwards.

The theoretical equation from Turner et al. for the critical velocity of gas V_{cg} to lift a liquid is as follows [1, 4]:

$$V_{cg}=\frac{1.593\times E\times \sigma^{\frac{1}{4}}\times\left(\rho_l-\rho_g\right)^{\frac{1}{4}}}{\rho_g^{\frac{1}{2}}}\quad \text{(ft/sec)} \qquad (1)$$

Where,
σ – surface tension, dynes/cm;
ρ_l – density of liquid, lbm/ft^3;
ρ_g – density of gas, lbm/ft^3.

E – correction (efficiency) factor. The value of E for Turner model equals 1.2. To convert ft/sec to m/sec, it is required to divide the above -mentioned expression by 3.28 (1 m = 3.28 ft).

From critical velocity (1), a critical gas flow rate (q_g) can be presented in the following way:

$$q_g = \frac{3.067 \times P \times V_{cg} \times A}{(T+460) \times z} \text{ (Mscf/D)} \quad (2)$$

Where,
P – surface pressure, psi;
T – surface temperature, ^{0}F;
A – tubing cross sectional area $\left(A = \frac{(\pi) \times d_{ii}^2}{4 \times 144} \right)$, ft^2;
dii – tubing ID, inches. To convert q_g (Mscf/D) to q_g (10^3 m^3/day), it is required to divide the above- mentioned expression by 35.31.

Due to these equations, it can be concluded that if the flow rate of the well is greater than the critical rate, then liquid loading will not be expected. Critical velocity equals 1.1 m/s, critical gas rate equals 26.6 10^3m^3/day for wells with 73 mm OD tubing and equals 40 10^3m^3/day for wells with 89 mm OD tubing (A12, A26, A27, A36) in Field A.

The gas velocity and gas rate of the wells are presented in figure 2. This figure also shows the critical gas velocity and the critical gas rate (straight lines). In this case, the wells A11, A12, A22, A24, A26 and A33 have a problem with liquid loading, while wells A35 and A31 have a gas rate close to the critical gas rate. There are several methods to solve this problem. For example, by using free piston; foam injection down to the bottomhole, lifting tubing with a smaller diameter, etc. [2 – 4]. All these methods are used to remove liquid from the bottomhole or increase the well productivity (to some extent). It was decided in this study to increase the productivity of the wells when liquid loading occurs in order to solve this problem. A hydraulic fracturing treatment was chosen as a method to improve production, exclude problems with liquid loading by increasing gas rate and, therefore, increasing gas velocity.

The value of erosional velocity was also estimated. To avoid the appearance of erosion in tubing, it is recommended that velocity in the tubing should be lower than erosional velocity. Erosional velocity was calculated with API RP 14E (1981, 1984) on the basis of the following empirical expression [5]:

$$v_e = \frac{C}{\sqrt{\rho_m}}, \quad (3)$$

Where,
C – empirical constant, usually between 100 and 125, it is 122 in SI units;
ρ_m – density of the fluid in the tubing, g/cm3;
v_e – erosional velocity, m/sec.

Erosional velocity changes from 10 m/sec to 13.5 m/sec in Field A (depending on the fluid density in the tubing) and on the average it is equal to 12.5 m/sec. According to figure 2, there are no wells with gas velocity higher than the erosional velocity. It is always checked due to further development prediction. No increase in gas flow velocity above the erosional velocity was detected during the years of stimulation.

3.2 Condensate banking in Field A wells

It is known that the accumulation of retrograde condensate through the reservoir and in the near-wellbore area of exploration wells differs due to changes in thermobaric conditions at the bottomhole of wells. Thus, based on the degree of condensate saturation, it is possible to separate two areas in porous media. They are the area of “static condensation” located far from a well and the area of “dynamic condensation” located near the wellbore. Condensation in the “static condensation” area is described by the process of differential condensation and depends on the pressure and composition of the initial mixture. Condensate accumulation in the “dynamic condensation” area depends on a fluid phase and mass transport of hydrocarbons. This process has the following mechanism: when there is gas passage through the point of a reservoir where pressure is lower than the dew point pressure, the condensation process occurs. In a high pressure gradient area, a dropped-out fluid (condensate) can be permanent (in case of critical saturation) or it can be moved with velocity, lower than the velocity of gas. With the passage of each new portion of gas through this point of the reservoir, retrograde condensate comes out of solution and,therefore, the process of condensate accumulation takes place here. As the result of this process, the saturation of liquid (condensate) in the near-wellbore area can exceed the average value of condensate saturation largely compared to the remaining part of the reservoir and condensate banking is formed near a wellbore [6].

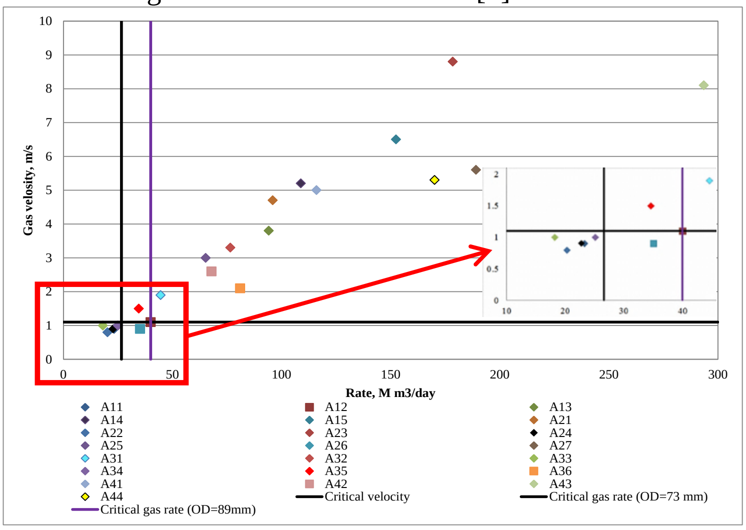

Figure 2. Gas velocity versus gas rate for wells (rhombus – wells with 73 mm OD tubing, square – wells with 89mm OD tubing)

At the pressure above the dew point, well rate is defined by permeability, net pay thickness of the reservoir and viscosity of gas. When the flowing bottomhole pressure falls below the dew point, liquid condensate builds up (condensate banking) near the wellbore area with high condensate saturation. The parameters of this condensate banking (size and saturation of condensate) depends on some additional factors, such as relative permeability of gas and condensate, pressure distribution in the reservoir and PVT properties of the system. Condensate saturation near a wellbore can reach 40-60%, therefore, there can be a several-time decrease in well productivity [7 - 9].

Thereafter, using a simulation model, the content of gas condensate in the near-wellbore area in wells without hydraulic fracturing treatment was analyzed. There are profiles of condensate saturation for one well from each cluster presented in figure 3. To achieve these results, the local refinement procedure was performed for every well left without hydraulic fracturing. From these figures, it can be concluded that there is condensate banking taking place in all the wells.

There are several technologies to improve the productivity of gas condensate wells providing bottomhole treatment with different solvents, reagents and thermal treatment to remove condensate banking [10, 11]. However, a hydraulic fracturing treatment seems to be one of the most effective methods to improve the productivity of gas condensate wells [7, 12-15]. This treatment allows increasing the contact area of a well with the reservoir and decreasing the depression on the reservoir. It leads to the more proportional development of reserves and more optimal production of gas and condensate. Condensate banking will also take place, but the size and profile of condensate saturation in the near-wellbore area will change. Condensate will drop out along the fracture and after entering the fracture it will move with gas flow to the surface [7].

4. Research techniques

The Field A development optimization was performed with the use of an integrated model built with the Avocet Integrated Modeling® software (Schlumberger). Making this model included the following steps:

1. A gathering facilities system model was created with the Pipesim® software (Schlumberger);
2. The gathering facilities system model was connected to the simulation model (input data) with Avocet Integrated modeling;
3. History matching of the integrated model as of 01.01.2014.

These steps will be described in more detail below.

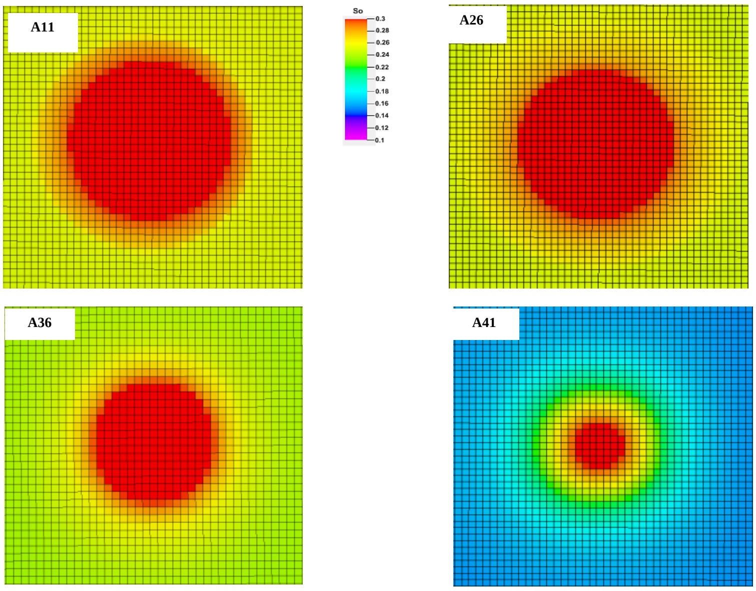

Figure 3. Condensate saturation profile for wells A11, A26, A36, A41

4.1. "Gathering facilities system" model creation

The gathering facilities system model was built with the Pipesim® software (Schlumberger). The model is presented in figure 4. For the correct description of the multiphase fluid filtration and due to the changes in the phase state of the system resulting from a reservoir pressure drop, the compositional model was used in the Pipesim software, as well as in the simulation model. The water cut of the fluid was also taken into account in the model. All perforated intervals in production wells are located above the gas-water contact, and at the beginning of 2014 the water cut was equal to 5% in Field A.

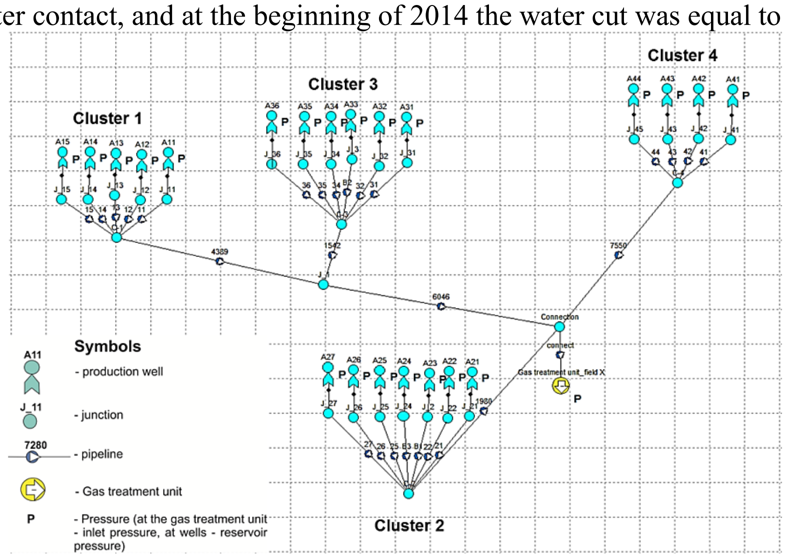

Figure 4. The gathering facilities system model of gas and condensate Field A in Pipesim® (Schlumberger)

4.2 "Reservoir – well – gathering facilities system" integrated model creation
The integrated model "reservoir – well – gathering facilities system" was built with Avocet Integrated Modeling® (Schlumberger) software. The composition simulation model was connected with the above-described gathering facilities system model. The connection point of these two models is bottomhole pressure (BHP). Therefore, all information about the reservoir is taken from the simulation model (to the bottomhole) and other information, such as construction of wells and surface facilities system were taken from the "gathering facilities system" model (above the bottomhole). A constraint between the models was the gas rate in the main phase in Field A. Bottomhole pressure was calculated as the result of balancing the simulation and gathering facilities system models. The difference in the solution of both models falls within range of 1% (set in the program). Each well in both of these models was connected to each other at the bottomhole.

As the simulation model and the gathering facilities system models are both compositional models, the integrated model is also compositional. The value and characteristics of each element in the reservoir mixture were taken into account. Each element from the simulation model was connected to a corresponding element in the gathering facilities system model. The Peng-Robinson equation of state is used in all of these models [16].

The integrated model was history-matched with the data as of 01.01.2014 and includes history matching in terms of the following parameters:
1. tubing head pressure (THP) at wells;
2. temperature and pressure distribution in wells;
3. gas and condensate rate.

5. Development optimization

5.1. Hydraulic fracturing treatment design
The design of hydraulic fracturing was created using the Unified fracture design technique described by M. Economides and P. Valco [17, 18] for three different types of proppants. It should be mentioned that hydraulic fracturing not only solved the problems mentioned above, but also allows developing the field with a lower level of depression at same flow rates.

5.2. Description of development scenarios
To obtain the optimal development plan for 8 years, different scenarios of field development were analyzed. Each of these scenarios was also assessed from the economic point of view.

Development optimization was performed in the following way: firstly, the base scenario (described below) was considered, then the results of this scenario were analyzed and economic indicators were calculated. Later, the conditions of the constant gas rate and positive NPV were checked. If both of these conditions were met, this scenario was chosen as optimal (recommended) for further optimization. If no, this scenario was optimized and the cycle was repeated until both conditions were met. Five groups of scenarios were considered.

Base scenario. This scenario is without new wells and treatment. The number of wells remains constant (22 wells). Gas and condensate cumulative production and also annual production of gas and condensate are presented in figures 5-6. From these figures, it can be seen that gas and condensate production falls continuously. After 8 years, the production level decreased to 45%. The condensate and gas recovery factors in 2022 are equal to 34.3 and 44.9, respectively.

Scenario 1. According to the Field A technological development plan, four new wells will be put into production in 2017 and 2019. Field condensate and gas cumulative production and annual production of gas and condensate are presented in figures 5-7. It can be concluded from these figures that the production of gas and condensate is also falling. An increase in production is observed in years when new wells were drilled. The condensate and gas recovery factors are equal to 0.357 and 0.47, respectively. Therefore. steps should be taken to stop the production decline.

Scenario 2. This scenario is based on hydraulic fracturing treatment in all wells at the beginning of the simulation period (January-February 2014).

It is known that production changes in one well in a gas-condensate field leading to changes in production in adjacent wells, as the gas phase is high-mobility. Modeling this scenario has brought the following results: three wells were not to become producers from the beginning of the stimulation and all wells were to show lower production rates. As it can be seen from figures 5-6, the production of gas increased up to 20% during the first year, then production trend waas falling until the year when new wells were put into production. The condensate and gas recovery factors are equal to 0.37 and 0.5, respectively.

As there are some problems with the flowing of three wells and reducing rates before the further optimization of Field A development, it was decided to analyze the influence of hydraulic fracturing for one well on adjacent wells. The task was limited to the consideration of the influence this treatment has on each cluster separately. Therefore, a hydraulic fracture treatment was modeled for every well separately from other wells on the cluster and then the influence of each treatment was analyzed. It was found out that each hydraulic fracturing treatment exerts influence on adjacent wells to some extent. Therefore it was decided to treat no more than one well per cluster at a time.

Scenario 3. In this scenario, hydraulic fracturing was consistent. It was concluded that firstly hydraulic fracturing treatment will be made in wells that have problems with liquid loading to exclude their shutdown. Then hydraulic fracturing will be performed for wells where gas rates are becoming close to the critical values and later for the remaining wells. All wells have been in production during 8 years in contrast to scenario 2.

To get the best result, different options of a hydraulic fracturing schedule were analyzed. It refers to wells with liquid loading problems. This analysis was made to exclude well shutdown. To predict the well shutdown, a restriction represented by the critical gas rate was established for each well. If the gas rate in a well fell below the critical gas rate, the well was shut down. The procedure of hydraulic fracturing will be held for three wells from different clusters according to the schedule.

When new wells are put into production (2017, 2019, as it was mentioned above), hydraulic fracturing will have already been held for all wells with the liquid loading problem. Therefore, to fulfill the objective of this project and exclude a higher increase in gas production, no hydraulic fracturing will be held in these years.

It is known that reservoir pressure declines with time. The faster reservoir pressure declines, the bigger volume of condensate remains in the reservoir. In Area 1, reservoir pressure is practically 152 atm, as it was mentioned above, as in Area 2 it has dropped to 205 atm. Gas recycling process is not provided in Field A. Therefore, the large amount of condensate starts to remain in the reservoir in the first area.

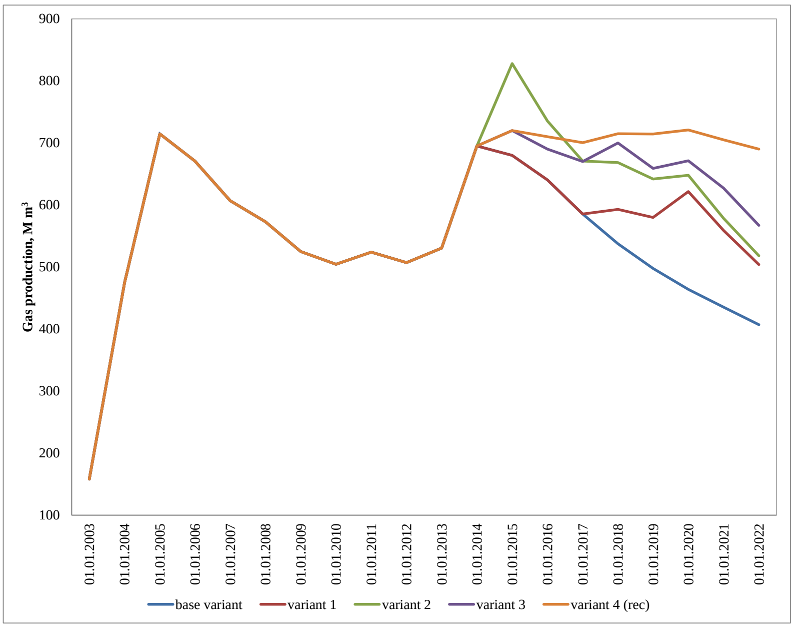

Figure 5. Annular gas production, 2002-2022

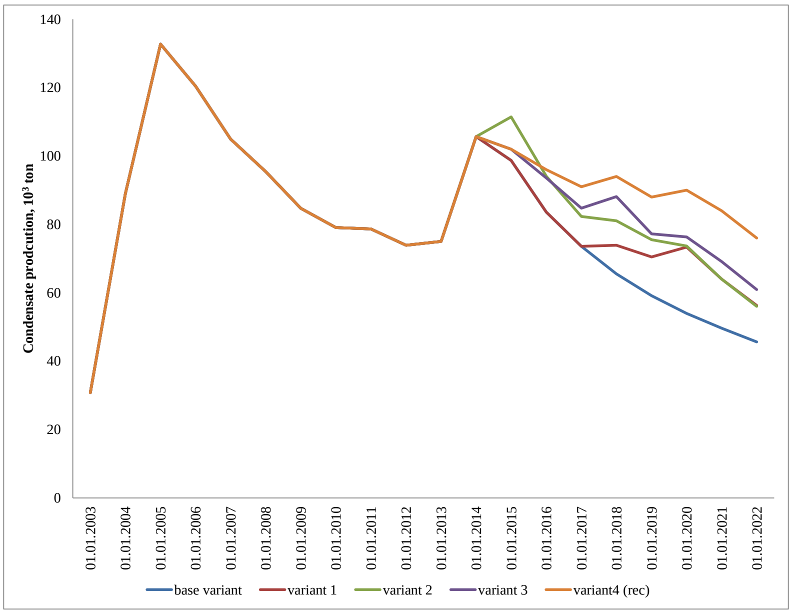

Figure 6. Annular condensate production, 2002-2022

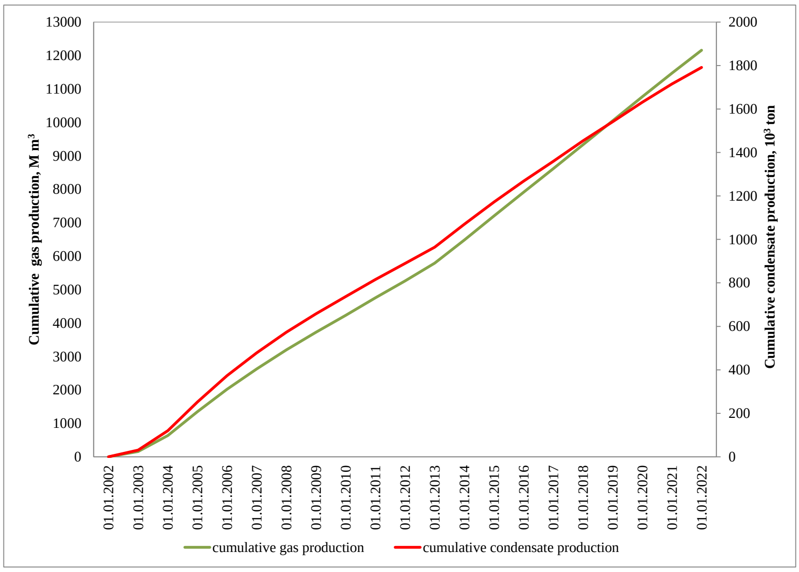

Figure 7. Cumulative gas and condensate production

In order to increase the production of condensate from the cluster, four technique described by A. Kalugin in [19] and [20] were considered. The main issue of this technique is condensate recovery maximization. It is achieved with the allocation of the gas rate in a well, namely – decreasing the gas rate in adjacent wells and increasing rates on remote wells. Condensate recovery increases due to the redistribution of pressure in the reservoir. It was decided to limit gas rates for wells A43 and A44, while wells A41 and A42 are fully opened during the first year, then during the second year of development gas rates in wells A43 and A44 will be increased (the well will be unfastened, but not fully opened) instead of wells A41 and A42 where rates will be limited and vice versa up to 2020. This year, wells A41 and A42 will be fully opened while wells A43 and A44 will be unfastened.
Three scenarios were considered. The first scenario: all wells in cluster 4 are fully opened, the second scenario: wells A43 and A44 are unfastened, the chokes of these wells stay the same as on 01.01.2014. The third (recommended) scenario is the scenario that is described above. Cumulative and annular condensate production and reservoir pressure profiles are presented in figures 8-9. According to the obtained results, it can be concluded that the third scenario is optimal for the further development of cluster 4. Despite the fact that the production of condensate in the first scenario is more than the value of 13 thousand suggested by the recommended option, reservoir pressure in the optimal scenario is 35 atm higher at the end of the stimulation period (figure 10).

The recommended scenario for cluster 4 was taken into consideration in scenario 3 of field development and in further scenarios.

As it can be seen from figure 5A, the production of gas is at the same level during the first three years and then it starts declining. The condensate and gas recovery factors are equal to 0.369 and 0.493, respectively.

During these four scenarios, the inlet pressure at the gas treatment unit is maintained at the same level (76 atm). Gas production does not correspond to the project objective.

Scenario 4. To hold gas production at a constant level, it is also possible to reduce the inlet pressure at the gas treatment unit. The minimum pressure at gas treatment is 15 atm (it is a restriction from technical point of view). This scenario is a modified scenario 3 with a reduction in pressure at the gas treatment unit with time. The profile of pressure changes is presented in Table 2.

As one can see from figure 5A, gas production stays at the same level during the whole simulation period. Also it can be pointed out that the condensate and gas recovery factors are equal to 0.384 and 0.51, respectively. It should also be noted that condensate production in this scenario is the greatest.

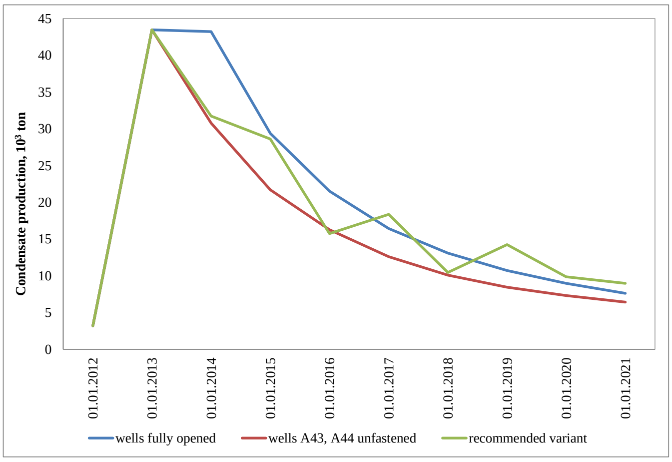

Figure 8. Annular condensate production (cluster 4)

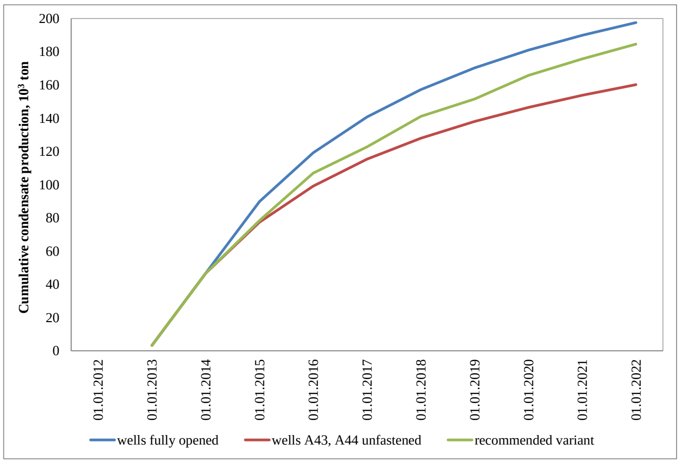

Figure 9. Cumulative condensate production (cluster 4)

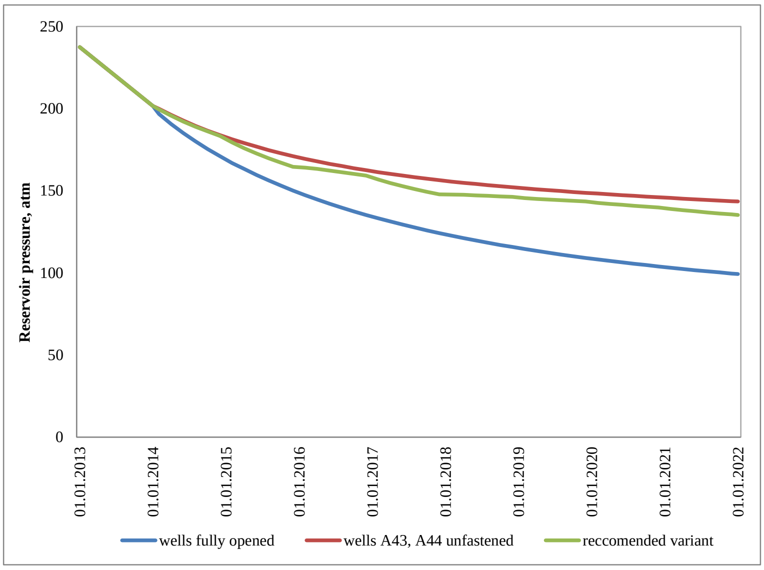

Figure 10. Reservoir pressure profile (cluster 4)

Table 2. Profile of inlet pressure at gas treatment unit

Year	Inlet pressure at gas treatment unit, atm
2014	76
2015	70
2016	64
2017	58
2018	52
2019	46
2020	40
2021	34

6. Economic factors

All these five scenarios were also considered from the economic point of view. In CAPEX, hydraulic fracturing treatments, drilling of new wells, building of a cluster base, pipeline from new clusters were taken into consideration. Also, it was concluded that acidizing treatment should be performed in a year to maintain the productivity of the wells. In OPEX, gas and condensate preparation and transportation and other production costs were taken into account. Also, the following taxes were considered: VAT, royalty. The discount rate was considered equal to 15%. All calculations were made in real terms. The condensate price equals 13,086.7 RUR/ton, the gas price is 3,463.3 RUR/103m3.

Due to the economic and simulation results, it was concluded that the optimal scenario for further development is scenario 4. It has the maximum NPV, gas and condensate production compared with other scenarios. It can also be noted that the reservoir pressure in this scenario is lower than in other scenarios as of 01.01.2022, however, this difference is not significant.

It should also be mentioned that scenario 2 is more attractive from the economic point of view because of the maximum incremental revenue in the first 2 years. However, this scenario was not chosen, as there is a problem with selling such a big volume of products.

The incremental NPV for the recommended scenario vs. the base scenario is presented in figure 11.

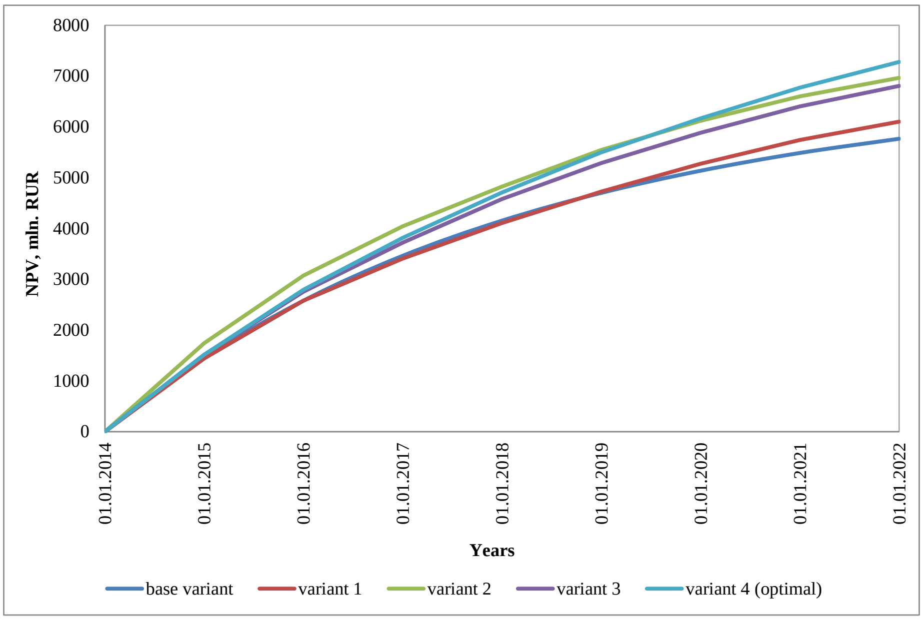

Figure 11. NVP of development scenarios of field A

Conclusions

Hydraulic fracturing treatment eliminated the liquid loading problem in the wells of Field A. Condensate banking after the hydraulic fracturing was not elimated, but, as it has already been mentioned, the size of profile and saturation changed. Therefore, condensate will be concentrated around the fracture and after entering the fracture it will flash to the surface by gas flow. Factors leading to the production decline were found. Creation an integrated model allowed optimizing Field A development for a 8-year period. Five groups of development scenarios were considered. After analyzing the results from the development and economic point of view, the recommended scenario for further development was chosen. According to this scenario, gas production in Field A was maintained at the same level (the difference being 3%) for 8 years. Cumulative gas production at the end of the optimization period equals 12,160.6 mln m^3 (Gas recovery factor – 0.51), cumulative condensate production equals 1.8 mln tons (condensate recovery factor – 0.38), the NPV of this scenario is 7,277 mln RUR.

References

[1] Yashaswini Devi Nallaparaju 2012 Prediction of Liquid Loading in Gas Wells *SPE 155356, SPE Annual Tecnical Conf. and Exh. (San Antonio Texas USA)*
[2] James F Lea and Henry V Nickens 2004 Solving Gas-Well Liquid-Loading Problems *SPE 72092*
[3] Mhunir Bayonle Alamu 2013 Gas Condensate Well Unloading Critical Rate *SPE 166350, SPE Annual Technical Conf. and Exh. (New Orleans Louisiana USA)*
[4] Kelkar Mohan 2008 *Natural gas production engineering* (Tulsa, Oklahoma) 572
[5] Economides Michael J 1994 *Petroleum Production System* ed Daniel A. Hill, Christine Ehlig-Economides (Prentice Hall PTR/ Upper Saddle River, New Jersey 07458*)* 611
[6] Jairam Kamath 2007 Deliverability of Gas-Condensate Reservoirs *Field Experiences and Prediction Techniques SPE 103433*
[7] Gritsenko A I 1997 Methods of Increasing Gas Condensate Well Productivity ed Ter-Sarkisov R M, Shandrygin A N, Podyuk V G (*Moscow: Nedra Publishing House)* 365
[8] Ignatyev A E 2011 Multiple Hydraulic Fracturing in Horizontal Wells as Method of Effective Development Gas Condensate Field of Arctic Region *SPE 1449925*
[9] Seminyakin V and Sigovatov L 2004 Features of Gas Flow in the Gas Condensate Wells *Gas industry* **7**
[10] Ter-Sarkisov R M, Shandrigin A N, Kireev C V, Vdovenko V L and Fedoseev A V 1997 Technology of Increasing Production from Gas Condensate Wells *20^{th} World Gas Conf. (Denmark)*
[11] Settari A et al. 1996 Production of Fractured Gas Condensate Wells – A Case Study of the Smorbukk Field *The Gas Technology Conf. (Calgary, Canada)*
[12] Langedijk R A et al. 2000 Optimization of Hydraulic Fracturing in a Deep, Multilayered, Gas Condensate Reservoir *SPE Annual Technical Conf. and Exh. (Dallas, Texas)*
[13] Al-Hashmi H S and Hashmi S S 2000 Long-Term Performance of Hydraulically Fractured Layered Rich Gas Condensate Reservoir *SPE International Oil and Gas Conference and Exhibition (Beijing, China)*
[14] Murrey M.D. et al Fracture Design, Execution, and Evaluation in Retrograde Condensate: Case History of Angsi Field, Offshore Malaysia, *SPE Annual Technical Conf. and Exh. (Denver, Colorado, October 5-8, 2003)*
[15] James Lea, Henry V. Nickens and Michael Wells *Gas Well Deliquification: Solution to Gas Well Liquid Loading Problems*
[16] Duns H. Jr. and Ros N.C.J 1963 Vertical Flow of Gas and Liquid Mixtures in Wells *Proc., Sixth World Pet. Cong. (Tokyo)* 451
[17] Economides M, Valko P and Oligney R Unified Fracture Design *(London IBT Global)* 262
[18] Shirley Indriati, Xiuli Wang and Michael J. Economides Adjustment of Hydraulic Fracture Design in Gas-Condensate Wells *SPE 73751, SPE International Symp. and Exh. of Formation Damage Control (Lafayette, Louisiana, February 20-21 2002)*

[19] Kalugin A 2012 Increase in Condensate Production from Gas Condensate Fields with Depletion Drive by Development Regulating *Applied Fluid Mechanics*. **2** (**14)** *ISSN 1561-9087*
[20] Kalugin A 2012 Increase in Condensate Production from Gas Condensate Field Through the Optimal Allocation of Gas Production *Exploration and development of oil and gas fields* (*ISSN 1993 – 9973)* **4 (45)**