RGNZ/MGPB

The effect of filling the gas pipeline with condensate on transport pressure

Rudarsko-geološko-naftni zbornik
(The Mining-Geology-Petroleum Engineering Bulletin)
DOI: 10.17794/rgn.2025.3.2

Professional paper

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Abstract

The analysis of the transportation of natural gases and associated petroleum gases indicates that, unlike natural gases, it is impossible to transport associated gases over long distances as a monophase state. In some cases, associated petroleum gas is injected into the reservoir to enhance oil recovery through gas lift operations. However, the specific demand for gas at production facilities is much lower compared to available gas resources. On the other hand, modern concepts regarding the use of natural gases and associated gases require that they are prepared and transported to the consumer in accordance with regulatory standards. The increased demand in export gas has made it necessary to collect, prepare, and transport the associated gases produced alongside oil without losses through pipelines to the destination.

Compared to dry gases, the collection and transportation of associated petroleum gases involve several technological challenges. During these processes, the pipeline may fill with condensate due to the condensation of the associated gas. This situation requires the calculation of gas condensation along the pipeline route.

This paper investigates the change in transportation pressure in the gas pipeline depending on the degree of pipeline filling with condensate at various gas flow rates. It has been found that during the multiphase flow of associated gas, an increase in pressure is observed due to the accumulation of condensate in the gas pipeline.

Keywords:

natural gas, associated gas, gas-condensate, transportation pressure, gas flow rate, separation of liquid phase

1. Introduction

It is known that at the outlet of the oil processing facility, the gas temperature is equal to its dew point temperature according to its hydrocarbons and water (moisture) content. These parameters generally coincide precisely with the oil's separation temperature and pressure. This indicates that as the gas temperature decreases, its relatively heavier components turn into liquid. In underground gas pipelines, the cooling of the gas occurs at temperatures significantly lower than the separation temperature at the depth of the trench where the pipeline is laid (**Guoxi, 2017; Gimaeva et al., 2019**).

If the distance to the gas processing plant exceeds 30-35 km, it becomes impossible to transport condensate-forming multiphase gas under separation pressure, and the construction of a compressor station significantly increases the cost of the gas. As a result, the accumulation of gas becomes inefficient for the facility (**Husna et al., 2023; Schouten et al., 2005; Zamrudy et al., 2021**).

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Received: 5 October 2024. Accepted: 15 January 2025.
Available online: 3 July 2025

2. Experimental part

Given the factors outlined above, analyzing the hydraulic characteristics of the designed gas pipeline is essential for making informed technical decisions about the efficient use of associated petroleum gases. To achieve this, it is first necessary to establish the input data required for the calculations. The composition of the transported gas is presented in **Table 1**.

The following initial data were used for hydraulic calculations:

- The length of the gas pipeline: L=120 km;
- Gas flow rate: $Q_g=6 \cdot 10^3$ m³/hour;
- Condensate flow rate: $Q_c=0.864$ m³/hour;
- Density of gas at normal conditions: $\rho_g=0.92$ kg/m³;
- Density of condensate: $\rho_c=630$ kg/m³;
- Gas viscosity $\mu_g=2 \cdot 10^{-5}$ Pa·s;
- Condensate viscosity $\mu_c=10^{-3}$ Pa·s;
- Pressure at the end of the gas pipeline: $P_{end}=0.2$ MPa;
- Initial gas temperature: $T_{ini.}=333$ K;
- Oil separation parameters: $P_{sep.}=0.9$ MPa, T=333 K.
- Ambient temperature: $T_{amb.}=273$ K.
- Molar mass of gas composition: M=20.61 g/ mol.

Table 1. Component composition of associated gas

Components	Mass fraction %	Components	Mass fraction %
CO_2	0.984	i-C_4H_{10}	2.962
N_2	1.593	n-C_4H_{10}	5.811
CH_4	65.279	i- C_5H_{12}	1.471
C_2H_6	6.070	n- C_5H_{12}	1.611
C_3H_8	12.839	C_6H_{14}+	1.380

sure in both mono and multiphase flows. **Figure 2** illustrates the pressure variation along the pipeline for these flows.

In the next stage of the calculation, the maximum gas condensation point along the pipeline was analyzed. For this purpose, the relevant "pressure-temperature" parameters of the two phases were selected from the hydraulic calculations. At this point in the pipeline, the gas temperature reached its minimum value of 273 K (ambient temperature), beyond which no further gas condensation is expected. Between section 0 and section 12, only three data sets are available, which are insufficient to accurately identify the maximum condensation point. To enhance accuracy, an additional hydraulic calculation is needed for the 12 km section of the pipeline. Based on the initial calculation, a pressure of 3.11 MPa (see **Table 3**) for the multiphase flow at the 12 km mark is used as the starting value.

Table 2. Initial transport pressure variation for mono and multiphase flows

Inner diameter, m	Initial pressure, MPa		Inner diameter, m	Initial pressure, MPa	
	monophase	multiphase		monophase	multiphase
0.15	4.50	5.634	0.50	0.265	1.850
0.20	1.96	3.291	0.60	0.229	1.870
0.25	1.07	2.515	0.70	0.214	1.910
0.30	0.68	2.170	0.80	0.208	1.954
0.40	0.36	1.90			

Using the initial data, hydraulic calculations were conducted for the gas pipeline. The first stage involved evaluating various combinations of pipeline diameter and inlet pressure for both monophase and multiphase flows. The results of these calculations for pipelines with different diameters are presented in **Table 2**.

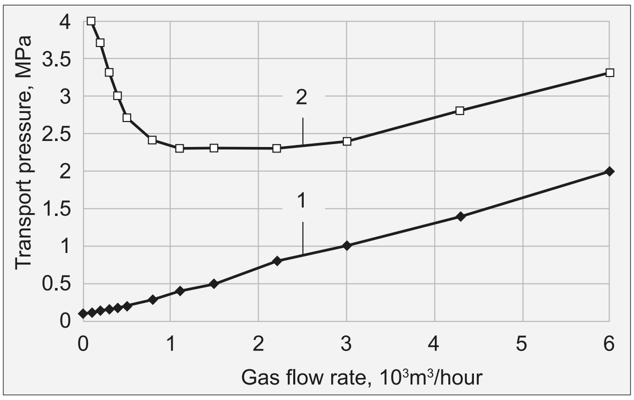
When selecting the diameter of the gas pipeline, the dynamics of gas flow must be carefully considered. If the maximum gas flow rate is provided as initial data, transportation can only be achieved under high-pressure conditions during a reduction in flow rate. Consequently, the minimum transportation pressure cannot serve as the sole criterion for determining the pipeline diameter.

In multiphase flow, unlike monophase flow, a decrease in gas flow rate within the pipeline causes an increase in inlet pressure. Therefore, the potential for flow rate reduction should be factored into the selection of the pipeline diameter to ensure efficient operation (**Morenev et al, 2020; Veliev et al, 2020**).

As a result of the hydraulic calculations of the pipelines (see **Table 2**), it was determined that if the diameter of the gas pipeline is chosen as D=0.2 m, the operation of the pipeline is realized at the initial pressure of 3.3 MPa.

So, as can be seen from **Figure 1**, the option of assuming the diameter of the gas pipeline D=0.2 m allows changing the gas flow rate in the system in the range from 1000 to 6000 m^3/h. That is, despite the reduction of gas flow rate in the system by 6 times, the initial transport pressure remains almost unchanged. Thus, hydraulic calculations for the gas pipeline were carried out by accepting the diameter of the gas pipeline is D=0.2 m. Calculations were performed for monophase and multiphase flows. The operating 120 km gas pipeline is divided into 20 sections, each 6 km long.

Table 3 presents the calculated values for average flow velocity, absolute temperature, and absolute pressure



1-monophase, 2- multiphase

Figure 1. Hydraulic characteristics of the gas pipeline (D= 0.2 m)

Table 4 presents the variation in average flow velocity and the "pressure-temperature" parameters along the initial section of the gas pipeline (0-12 km). Gas condensation was calculated based on the changes in these parameters by appling the phase equilibrium constant. The results, along with the dependence of gas condensation on pipeline length, are illustrated in **Figure 3**.

As shown in **Figure 3**, the maximum gas condensation occurs at 8% in the 7.2 km section of the pipeline. Based on these calculations, if a combined transporta-

Table 3. Change of transport parameters in the gas pipeline

Sections, km	Average flow velocity, m/s	Temperature, K	Pressure, MPa	
			Monophase	Multiphase
0	2.56	333	2.07	3.39
6	2.65	273.5	2.01	3.26
12	2.73	273	1.96	3.11
18	2.81	273	1.90	2.97
24	2.90	273	1.84	2.83
30	3.10	273	1.78	2.69
36	3.20	273	1.72	2.55
42	3.36	273	1.66	2.41
48	3.49	273	1.59	2.26
54	3.65	273	1.52	2.12
60	3.87	273	1.45	1.98
66	4.07	273	1.38	1.84
72	4.36	273	1.30	1.69
78	4.66	273	1.22	1.55
84	5.08	273	1.14	1.40
90	5.59	273	1.05	1.25
96	6.26	273	0.95	1.10
102	7.29	273	0.85	0.95
108	6.98	273	0.73	0.79
114	8.96	273	0.69	0.62
120	26.64	273	0.20	0.20

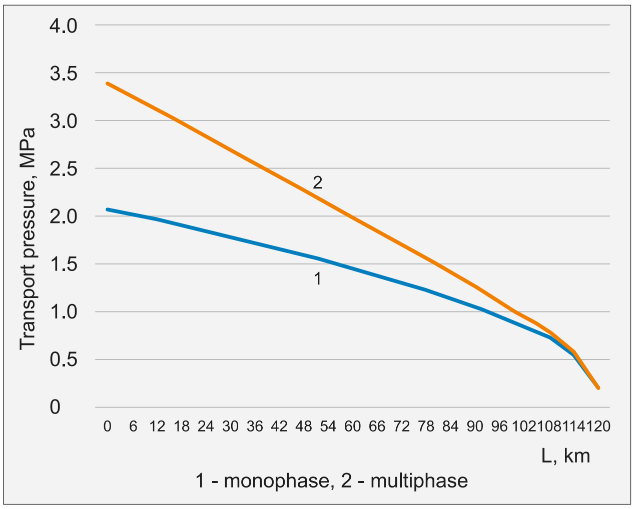


Figure 2. Change in pressure in the gas pipeline (D= 0.2m)

tion method involving liquid phase (condensate) removal is adopted, additional gas separation equipment should be installed after the 7.2 km mark. The maximum amount of condensate to be removed from this section of the pipeline can then be determined as follows:

$$Q_c = \frac{8\rho_g Q_g}{100\rho_c} = \frac{8 \cdot 0.92 \cdot 6000}{100 \cdot 630} = 0.701\,\mathrm{m}^3\,/\,\mathrm{hour} \qquad (1)$$

It should be noted that during gas transportation, the pressure difference at which condensate removal is possible should be taken into account. For this purpose, the gas pipeline (length is 120 km) should be divided into the following two parts: one of them is the section from the beginning until the additional separation unit, i.e. the section of the pipeline up to the point of maximum condensation (the length of this section is $l_1 = 8$ km). The second part is the rest of the pipeline. The length of this part will be $l_2 = L - l_1 = 120 - 8 = 112$ km. Then the hydraulic calculation for both parts was carried out separately. The hydraulic calculation for the first part should be done according to the methodology for multiphase transport, but for the last part should be done according to the methodology for monophase flow. In this case, the starting pressure for monophase transport in the second part should be taken as the final pressure at the outlet of the initial part of the pipeline (part 1). The results of the hydraulic calculation of the last (2nd) part of the gas pipeline are given in **Table 5**.

The results of the hydraulic calculation for the multiphase flow in the first (starting) part of the gas pipeline are given in **Table 6**. In this part, P_{outlet}=1.88 MPa.

As shown in **Table 6**, the pressure at the inlet of the first section of the gas pipeline at the 8 km mark is 2.07 MPa. Given that the inlet pressure without condensate removal is 3.39 MPa it is possible to reduce the pressure by 1.32 MPa (3.39-2.07=1.32 MPa) through the installation of an additional separation device.

The first challenge is identifying the C_{6+} residue during the condensation process. Typically, calculations are

Table 4. Change of flow parameters in the initial part of the gas pipeline

Sections, km	Average flow velocity, m/s	Temperature, K	Pressure, MPa	
			Monophase	Multiphase
0	1.67	333.0	3.19	3.39
0.6	1.67	309.9	3.19	3.38
1.2	1.67	295.7	3.18	3.37
1.8	1.68	286.9	3.18	3.36
2.4	1.68	281.6	3.18	3.34
3.0	1.68	278.3	3.17	3.33
3.6	1.68	276.2	3.17	3.31
4.2	1.68	275.0	3.17	3.30
4.8	1.69	274.2	3.16	3.29
5.4	1.69	273.7	3.16	3.27
6.0	1.69	273.5	3.15	3.26
6.6	1.69	273.3	3.15	3.24
7.2	1.70	273.2	3.15	3.23
7.8	1.70	273.1	3.14	3.21
8.4	1.70	273.1	3.14	3.20
9.0	1.70	273.0	3.13	3.19
9.6	1.70	273.0	3.13	3.17
10.2	1.71	273.0	3.13	3.16
10.8	1.71	273.0	3.12	3.14
11.4	1.71	273.0	3.12	3.13
12.0	1.71	273.0	3.11	3.11

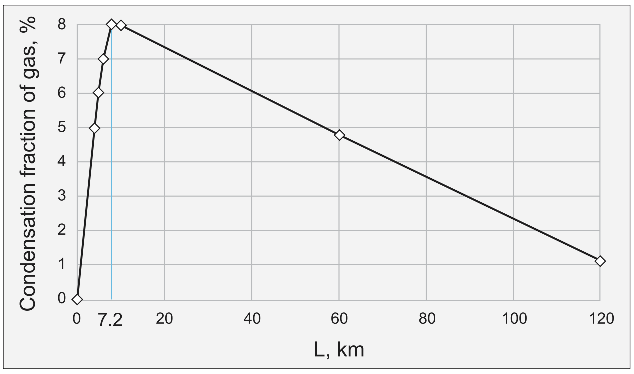


Figure 3. Variation of the of gas condensation along the pipeline

based on phase equilibrium coefficients. However, for the C_{6+} group, which consists of several components in unknown proportions, the phase equilibrium coefficient is not well-defined. (**Ismayilov et al., 2019; Ismayilov et al., 2020; Ismayilov et al., 2024**). Therefore, for the preliminary calculation, we assume that the group consists consists solely of C_{6+}. The dew point temperature is first determined, after which calculations are carried out by replacing the C_{6+} group with components C_7, C_8, C_9, C_{10} and C_{11}. The obtained results are given in **Table 7**.

As can be seen from **Table 7**, due to the dew point calculated for the condensate, the gas composition, in which the C_{6+} residue is identified as C10, corresponds to a temperature of 330.12 K (57.12°C). In this case, in

Table 5. Calculation results of the last (2nd) section of the pipeline for monophase flow

Length, km	Average flow velocity, m/s	Temperature, K	Monophase flow pressure, MPa
0	2.82	273	1.88
5.6	2.90	273	1.83
11.2	2.98	273	1.78
16.8	3.07	273	1.73
22.4	3.17	273	1.67
28.0	3.28	273	1.62
33.6	3.40	273	1.56
39.2	3.53	273	1.50
44.8	3.68	273	1.44
50.4	3.84	273	1.38
56.0	4.03	273	1.32
61.6	4.24	273	1.25
67.2	4.49	273	1.18
72.8	4.78	273	1.11
78.4	5.14	273	1.03
84.0	5.58	273	0.95
89.6	6.15	273	0.86
95.2	6.92	273	0.77
100.8	8.05	273	0.66
106.4	9.96	273	0.53
112.0	26.54	273	0.20

Table 6. Calculation results of the first section of the pipeline for multiphase flow

Length, km	Average flow velocity, m/s	Temperature, K	Multiphase flow pressure, MPa
0	2.72	333.0	2.07
0.4	2.73	316.1	2.06
0.8	2.73	303.9	2.05
1.2	2.74	295.2	2.04
1.6	2.74	289.0	2.03
2.0	2.75	284.5	2.02
2.4	2.75	281.3	2.01
2.8	2.76	278.9	2.01
3.2	2.76	277.3	1.99
3.6	2.77	276.1	1.98
4.0	2.77	275.2	1.97
4.4	2.78	274.6	1.96
4.8	2.79	274.1	1.95
5.2	2.79	273.8	1.94
5.6	2.80	273.6	1.93
6.0	2.80	273.4	1.92
6.4	2.81	273.3	1.91
6.8	2.81	273.2	1.90
7.2	2.82	273.1	1.89
7.6	2.82	273.1	1.88
8.0	2.83	273.0	1.88

Table 7. Calculated results for C_{6+} group

C_{6+}	Pressure, MPa	Temperature, K	Final boiling temperature, K (°C)
C_6	0.9	333	269.47 (-3.53)
C_7	0.9	333	282.78 (9.78)
C_8	0.9	333	298.82 (25.82)
C_9	0.9	333	314.9 (41.09)
C_{10}	0.9	333	330.12 (57.12)
C_{11}	0.9	333	343.05 (70.05)

the example of a gas pipeline with a length of 120 km and a diameter of 0.2 m, at the point of maximum condensation at P=1.89 MPa, T=273.1 K (see **Table 6**), the maximum gas condensation is 8% and the component composition of the condensate is as shown in **Table 8**.

Table 8. The component composition of the condensate

Components	Mass fraction %	Components	Mass fraction %
C_1	2.57	i-C_5	10.361
C_2	1.257	n-C_5	14.272
C_3	12.147	C_{10}	32.897
i-C_4	6.925	CO_2	0.184
n-C_4	19.102	N_2	0.015

Based on the component composition of the condensate (see **Table 8**), the following parameters can be determined:

- The evaporation rate of the condensate at atmospheric pressure and T=273 K (0°C). This indicator is crucial for determining the evaporation rate when filling the condensate into an open tank;
- The evaporation rate of the condensate at atmospheric pressure and T=313K (40°C). This indicator is important for determining condensate loss during transport in summer months;
- The vapor pressure of the condensate at T=311.8 K (38.8°C). This parameter is very important for determining the state of the condensate-whether it is a liquid hydrocarbon gas or a light viscous liquid;
- The vapor pressure of the condensate at T=323K (50°C). This characteristic is very significant for selecting equipment for transporting the condensate.

The results for these parameters are shown in **Table 9**.

Table 9. Parameters of condensate

Definition of indicator	Value
Evaporation rate, (%) at P=0.1 MPa, T=273 K	14 (C_2-4.2; C_3-29.4; C_4-41.5; C_5-17%)
Evaporation rate, (%) at P=0.1 MPa, T=313K	62
Vapor pressure, MPa, T=311.8 K	1.6
Vapor pressure, MPa, T=323K	1.8

As shown in **Table 9**, at T=311.8 K, the condensate in the pipeline is a liquid hydrocarbon gas with a vapor pressure of $P_{v.p.}$=1.6 MPa, therefore, it should be transported in specialized road or rail tankers designed for liquid propane.

When developing fields located more than 30 km away from gas consumers, it is essential to evaluate the feasibility of transportation options under oil separation pressure. This consideration arises from the characteristics of multiphase gas transportation. Transporting gas over distances greater than 30 km via pipeline under separation pressure is not practical. Consequently, to efficiently utilize associated petroleum gases, the following transportation options are primarily considered: (**Buslaev et al., 2015; Vorobev et al., 2019; Vovk et al., 2019**):

- Conversion of gas into electrical energy at the field's power station;
- Transportation of gas in a multiphase state to a gas processing plant using a compressor;
- Transportation of gas in a monophase state to a gas processing plant under separation pressure;
- Transportation of gas in a monophase state to a gas processing plant at the separation temperature of oil. This transportation involves isothermal transfer of gas at the oil separation temperature without a compressor;

- Combined transportation of gas without a compressor, with condensate removal from the pipeline;
- Multiphase transportation of gas with the inclusion of cleaning devices in the pipeline.

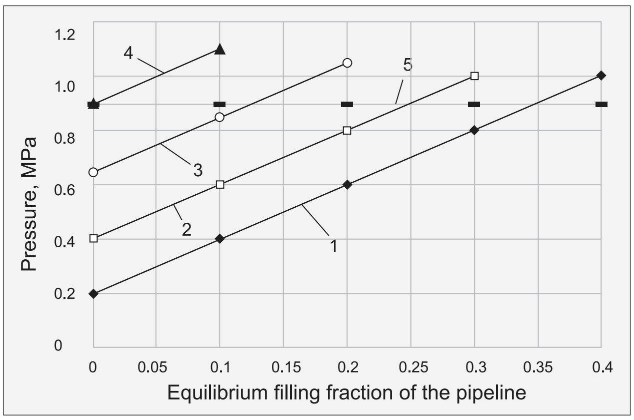
Literature often suggests injecting associated petroleum gas to enhance oil recovery through gas lift operations. However, these methods are not directly related to the utilization of associated gas, as they primarily involve gas circulation rather than its effective use (**Bayadilova et al., 2024; Deryayev, 2024**).

3. Results and discussion

The choice of a 0.20 m pipeline is based on its ability to consider the dynamics of gas resource -the possibility of a partial reduction of gas flow rate. Given the length of the existing pipeline (120 km), a combined transportation method (with condensate removal from the pipeline) is considered more suitable. In the next stage of analysis the method that allows reducing the construction costs of additional facilities (separation equipment) was investigated. Therefore, the pipeline with internal diameter of 0.25 m is studied. Such a pipeline allows the transportation of gas in a homogeneous state at oil separation pressure (P=0.9 MPa). Considering the length of the existing pipeline (73 km), there is no need to construct an additional separation unit. Instead, this option considers the multiphase transportation of gas, with periodic cleaning of accumulated liquid (condensate) using cleaning devices (pigs).

For the considered gas pipeline (D=0.25 m), the change in transportation pressure with various gas flow rates depending on the degree of pipeline filling with condensate is shown in **Figure 4**. The degree of filling with condensate is determined in portions with respect to the equilibrium filling volume of the pipeline.

As shown in **Figure 4**, as the equilibrium filling fraction of the pipeline increases, the transportation pressure increases for all values of gas flow rate.



1÷4 corresponding to gas flow rates of 1.5; 3.0; 4.5 and $6.5 \cdot 10^3$ m³/hour, 5- at a pressure of 0.9 MPa.

Figure 4. The effect of condensate accumulation in the gas pipeline on gas transportation pressure

As seen in **Figure 4**, the gas pipeline has the throughput of $6.5 \cdot 10^3$ m³/hour in a monophase state. However, if a multiphase flow is allowed, the pressure will increase due to the accumulation of condensate in the gas pipeline. To maintain the transport pressure at the level of the oil separation pressure, it is necessary to reduce the gas flow to $4.5 \cdot 10^3$ m³/hour. At this flow rate, the transport of gas at separation pressure is possible even when the condensate accumulates up to 12.5% of the equilibrium volume. Therefore, to ensure the normal operation of the gas transport system, it is sufficient to keep the gas flow at the level of $4.5 \cdot 10^3$ m³/hour. When the pressure at the pipeline inlet is 0.85 MPa, the filling rate of the pipeline will be approximately 12% of the equilibrium volume. When the pressure in the pipeline reaches 0.85 MPa, it is necessary to insert a cleaning device into the pipeline. After the cleaning device is inserted, the pressure at the pipeline inlet will stabilize at 0.64 MPa. Following this, a new cycle of condensate accumulation begins, leading to an increase in pressure at the inlet of the gas pipeline.

The equilibrium volume of liquid in the gas pipeline is determined by the graph shown in **Figure 5**, depending on the gas flow rate.

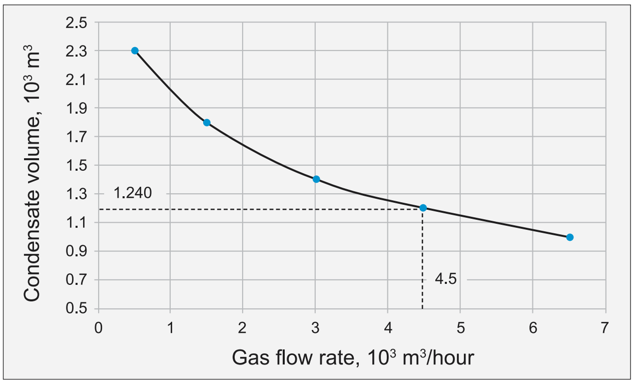


Figure 5. Condensate volume in gas pipeline (D=0.25 m, P=0.9 MPa)

As can be seen from the equilibrium volume of condensate in the gas pipeline (see **Figure 5**), at a gas flow rate of $4.5 \cdot 10^3$ m³/hour, the equilibrium volume of condensate is 1240 m³. The time required to accumulate this volume of condensate is approximately 4410 hours (considering the gas flow rate, condensate flow rate and parameters of the pipeline). The accumulation of 12.5% of condensate corresponds to a volume of 155 m³. The time required to accumulate this volume is 551 hours or 23 days. Therefore, to ensure the stable operation of the gas transport system, it is necessary to insert the cleaning device into the pipeline once a month.

As gas resources diminish, the interval between cleaning device insertions will lengthen. For instance, at a gas flow rate of 1500 m³/hour, the equilibrium volume of liquid in the gas pipeline reaches 1800 m³, and the time required for condensate accumulation is 266 days. The condensate filling rate of the pipeline is 35%, or 630 m³. In this scenario, pipeline cleaning to remove condensate can be performed once every three months.

4. Conclusions

1. The impact of condensate accumulation in gas pipelines on the transportation pressure, considering the resources of condensed associated petroleum gases, has been analyzed.
2. It was found that as the equilibrium condensate filling rate in the pipeline increases, the transportation pressure rises linearly across all gas flow rates. Additionally, the equilibrium volume of condensate in the pipeline decreases monotonically as the gas flow rate increases.
3. By considering the equilibrium condensate volume and the time required for its accumulation, the need for and frequency of cleaning the accumulated liquid to ensure the stable operation of the gas pipeline have been demonstrated.

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SAŽETAK

Utjecaj pojave kondenzata u cjevovodu na tlak transportiranja

Analiza transporta prirodnoga i kaptažnoga plina pokazuje da, za razliku od prirodnog plina, kaptažni nije moguće transportirati na velike udaljenosti u monofaznome stanju. U nekim se slučajevima kaptažni plin utiskuje u ležište kako bi se povećao iscrpak nafte pomoću plinskoga lifta. Međutim, specifična potražnja za kaptažnim plinom u proizvodnim pogonima puno je manja od raspoloživih količina. S druge strane, suvremeni koncepti korištenja prirodnoga i kaptažnoga plina zahtijevaju njihovu pripremu i transport do potrošača u skladu s regulatornim standardima. Povećana potražnja za prirodnim plinom dovela je do potrebe prikupljanja, pripreme i transporta kaptažnoga plina, proizvedenoga uz naftu, bez gubitaka kroz cjevovode do odredišta.
U usporedbi sa suhim plinom sabiranje i transport kaptažnoga plina uključuje nekoliko tehnoloških izazova. Tijekom tih procesa može doći do pojave kondenzata zbog kondenzacije kaptažnoga plina. Zbog toga je potrebno proračunati kondenzaciju kaptažnoga plina duž trase plinovoda.
U ovome radu istražuje se promjena tlaka u plinovodu tijekom transporta, ovisno o stupnju ispunjenosti plinovoda kondenzatom pri različitim brzinama protoka plina. Utvrđeno je da tijekom višefaznoga protoka kaptažnoga plina dolazi do porasta tlaka zbog prisutnosti kondenzata u plinovodu.

Ključne riječi:
prirodni plin, kaptažni plin, kondenzat, tlak transporta, protok plina, izdvajanje tekuće faze

Author's contribution

Elman Iskandarov (Doctor of technical sciences, Professor, transportation and storage of oil and natural gas) proposed the idea and guided the research. **Fidan Ismayilova** (PhD, Associated Professor, transportation and storage of oil and natural gas) examined the results and manuscript editing. **Mahammad Shukurlu** (PhD student of transportation and storage of oil and natural gas) performed tests and provided the report. **Anar Nagizadeh** (PhD student of transportation and storage of oil and natural gas) performed tests and provided the report.
All authors have read and agreed to the published version of the manuscript.