Gas and water content’s monitoring of crude oil in pipeline during production in Arctic shelf

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Abstract. The gradual depletion of onshore oil and gas fields and the aggravation of the global energy crisis lead to intensive development of oil and gas resources on the continental shelf, in particular, the Arctic shelf. When monitoring of oil production from wells in the conditions of Arctic shelf, it is necessary to measure free gas concentration and water content in oil-gas-water mixture in a pipeline. The paper discloses a method for non-contact monitoring of gas concentration and the water cut of products of oil wells in a pipeline, as well as presents the results of industrial studies of the interaction between gamma radiation and a flow of oil-gas-water mixture. Conclusions are formulated about the advantages of using and the feasibility of using this method for measuring the concentration of free gas and the water content in the oil-gas-water mixture during oil production.

1. Introduction
The gradual depletion of onshore oil and gas reserves and the exacerbation of the global energy crisis have triggered an even more intensive development of oil and gas resources of the continental shelf, in the interior of which there is almost three times more oil and gas than onshore [1]. In connection therewith, the production of hydrocarbons is intensively developing on the continental shelves of the seas all over the world. To date, world distribution of oil reserves by regions of the planet is as follows [2]:

- Middle East: 48.3%
- South and Central America: 18.8%
- North America: 13.7%
- Russia and CIS countries: 8.4%
- Africa: 7.2%
- Asia and the Pacific: 2.8%
- Europe: 0.8%

Russia owns the world’s widest shelf, which hosts multiple fields, and the development of offshore production is very promising for the Russian oil and gas industry [3]. Figure 1 presents the scheme for predicted oil production on the shelf of Russia, wherein the expected significant increase in production on Arctic shelf is shown.
In terms of chemical composition, crude oil, recovered from production wells or squeezed out of oil-and-gas bearing structures on the seabed, is a complex mixture of several thousand individual chemicals and compounds, mainly including liquid (saturated and unsaturated) hydrocarbons (80-90%) admixed with other organic compounds (naphthenic acids, asphaltenes, resins, mercaptans, etc.), as well as water (up to 10%), dissolved gases (up to 4%), mineral salts and trace elements. Having analyzed 500 samples of various oils, it was revealed that the average composition of “typical” oil is 57% aliphatic hydrocarbons, 29% aromatic hydrocarbons, 14% asphaltenes and other complex non-hydrocarbon compounds [5].

During recovery and primary processing, crude oil is twice mixed with water: firstly, when leaving the well together with the associated formation water and secondly – in the process of desalting, i.e., flushing with fresh water to remove chloride salts. Oil and water are separated by sedimentation, separation or, if it is present as a stable emulsion, using special dehydration procedures [6].

However, in the harsh Arctic conditions on the shelf, these methods further complicate and increase the cost of oil production without impurities.

When accounting for the products of oil wells on the shelf, it is necessary to consider changes in the component-wise composition of oil, which depend on the thermodynamic conditions of pumping, in particular, the presence of free gas and water in oil [7]. In addition, it is expedient to conduct these measurements directly in a pipeline and via a non-contact method.

To solve the set of aforesaid tasks, the radioisotope method of primary conversion of the parameters of oil flows in wells, due to the interaction between the controlled medium and flux of gamma rays, is very promising. The main advantage of radioisotope devices is the absence of contact when measuring [8]. Owing to this feature, these devices allow implementation of many tasks of monitoring and automation of various operating procedures, which, when using other physical principles, are rather challenging to solve or cannot be solved at all [9].

2. Measurement of gas concentration in oil and gas streams

The task of measuring free gas concentration in oil and gas streams can be reduced to the task of measuring the average density of a gas-liquid mixture. By measuring the density of the mixture $\rho_{mix}$ and knowing the density of liquid $\rho_{liq}$, gas concentration in the stream can be derived from the following relationship

$$\varphi = 1 - \frac{\rho_{mix}}{\rho_{liq}}$$

where $\rho_{mix} = \frac{1}{\mu_d} \ln(N_0 - N)$, $N_0$ is the pulse counting rate in the absence of the controlled medium in a pipeline; $N = N_0 \cdot \exp(-\mu \cdot \rho_{mix} \cdot d)$ is the pulse counting rate after interaction with the controlled
medium; $\mu$ is the mass attenuation coefficient of radiation; $d$ is the effective length of the irradiated layer of the controlled medium.

When measuring the density of the mixture, transported through large-diameter pipelines, by the radioisotope method, the total controlled volume is usually divided into elementary controlled volumes, each of which is irradiated with a narrow beam of gamma radiation. In this case, gas concentration $\varphi_i$ in each elementary volume is determined according to the formula

$$\ln \frac{N_{0i}}{N_i} = \varphi_i \cdot d_i \cdot \rho_{lg}.$$  \hspace{1cm} (2)

The average value of gas concentration in the total controlled volume is determined according to the formula

$$\varphi = \frac{\sum_{i=1}^{n} \varphi_i \cdot d_i}{\sum_{i=1}^{n} d_i},$$  \hspace{1cm} (3)

where $n$ is the number of elementary volumes.

When using this method for measuring free gas concentration in streams of commercial oil, the required measurement accuracy is not provided due to the uncertainty of the density values of oil without gas.

Currently, a measurement method, free of this drawback, has been developed. Improvement of the known method resides in the fact that the structural function of a change in density of the controlled medium is additionally determined in each elementary volume.

The structural function is the mean square of density increments in the controlled medium over the fixed time intervals $\tau$, i.e. 

$$T_{(c)} = \Delta \rho_{mix}^2.$$  

In this case, it is convenient to use this function to detect fluctuations in the measured parameter. By determining the density increments over short time intervals (for example, of the $10^{-3}$–$10^{-1}$ s order), it is possible to identify density fluctuations that are below the sensitivity threshold of known measuring instruments and are induced by fine gas bubbles. When the structural function in an elementary volume is equal to zero, this means that there are no increments in density of the controlled medium in it, and therefore, there is no gas, causing these increments occurrence.

After determining the structural function, one should find the elementary (control) volumes, in which it is equal to zero. Next, the actual value of the density of oil without gas is determined as the value of the density of the controlled medium in control volumes. Then, knowing the density of oil without gas, one should determine gas concentration in elementary volumes, in which the structural function is other than zero. To do so, one can use the following equation

$$\ln \frac{N_{0i}}{N_i} = \ln \left( \frac{N_{0c}}{N_{nc}} \right) = \ln \left( \frac{N_{0c}}{N_e} \right),$$  \hspace{1cm} (4)

where $N_{0c}, N_{nc}, N_e$ are the values of the pulse counting rate at the output of the detection block for the control volume.

In this case, free gas concentration in a pipeline is determined using the relationship (3).

The advantage of the described method resides in the fact that having made sure, via the structural function, that there is no gas in an elementary volume, the oil density therein can be measured with
high accuracy (up to hundredths of a percent), choosing the required measurement time without any restrictions.

A schematic diagram of the measuring device, that implements the described method, is shown in figure 2.

![Figure 2. The schematic diagram of the measuring device.](image)

The radioisotope primary density converter is installed on a pipeline 1 by means of a traveling mechanism 2. The latter is made in the form of a U-shaped frame that covers the pipeline cross-section. The side surfaces of the frame comprise carriages that allow installing on opposite sides of the pipeline and moving the radiation block 3 and the detection block 4.

The value of the elementary controlled volume is determined by the area of the sensitive surface of the detector and by the length of the corresponding chord of the pipeline cross-section, along which the irradiation takes place. Moving the radiation block and the detection block by means of carriages along the pipeline cross-section and turning the traveling mechanism around the axis of the pipeline, the cross-sections of the latter can be irradiated with gamma rays along almost any chord.

The output signal of the detection block is recorded by a frequency meter 5, connected to a digital-to-analog device. To automate the calculations, required to determine free gas concentration in commercial oil, a controller, which provides information processing and the issuance of measurement results on a real time basis, can be used.

Using the described method, studies of free gas concentration in commercial oil streams at an oil pumping station have been implemented.

2.1. Research results
The studies were carried out at a metering unit of the Nurlino oil pumping station of the Cherkassk department of oil pipelines of the Ural-Siberian department of trunk oil pipelines.

The objectives of the studies were to develop a technique for measuring free gas concentrations using radioisotope devices and to determine the distribution of free gas concentration in the measuring lines of metering units of oil pumping stations.

Figure 3 shows the layout of radioisotope primary density converters 1-3 on one of the measuring lines of the station. The measurements were performed in three cross-sections: at the input and output of the turbine flow transducer 4 and at the output of the filter 5.
Figure 3. Layout of primary converters on a measuring line of oil metering unit.

The outer diameter of the measuring line pipeline is 426 mm, the wall thickness is 13 mm. The width of a separate elementary controlled volume was determined by the diameter of the sensitive surface of the gamma-ray detector and made 30 mm. During the studies, 7 elementary volumes or chords of the pipeline cross-section, V1-V7, which were sequentially irradiated, were selected to perform measurements (see Fig.1).

The technique provided, in each elementary controlled volume, for at least 400 measurements of the counting rate of the output pulses with an averaging time of 10-2 s, required for determining the structural function, and five measurements with an averaging time of 100 s, required for determining gas concentration.

Control measurements, calibration of primary converters on the measuring line as well as measurements directly on the flow were performed during the study [10].

The control measurements were aimed at experimental evaluation of the measurement error. The measurements were conducted on the equivalent of the controlled section of a pipeline, made from a pipe, similar to the measuring line pipe, having a length of about 1 m.

The measurement technique is based on comparing the results of measuring free gas concentration using a radioisotope density converter with the results of direct measurements of free gas volume using a reference tank with a volume of 0.001 m3. When measuring, the radioisotope density converter was calibrated on an empty pipeline equivalent and on a pipeline equivalent filled with oil. In the equivalent of a pipeline, oil was preliminarily held for 24 hours. Then, oil in portions of 0.001 m3 each was sequentially poured from the pipeline equivalent, and the counting rate of the output pulses of the detection block in each elementary controlled volume was measured by moving the primary converter via the traveling mechanism. The total volume of discharged oil did not exceed 0.006 m3.

Experiments proved that the limiting value of the absolute error in measuring free gas concentration in commercial oil, using a radioisotope density converter, did not exceed 0.001 (1 liter of free gas per 1 m3 of oil).

During the calibration of a primary converter on the measuring line, the counting rate at the output of the detection block was measured for an empty pipeline and for a pipeline filled with oil being for sure free of gas, and the equipment self-noise power was determined for immobile oil.

Measurements on the flow of commercial oil have shown that there are density fluctuations in it, which significantly exceed self-noise of the equipment. These fluctuations are induced by variation in the controlled medium density, mainly due to the presence of free gas in the flow [11].

Figure 4 presents the research results for the distribution of free gas concentration over elementary volumes for various cross-sections of a pipeline in accordance with Fig.3.
Figure 4. Distribution of gas concentration in elementary volumes from top to bottom along I-III cross-sections of a pipeline.

The measured value of gas concentration in the pipeline as a whole was at least 0.004 (4 liters per 1 m³ of oil).

The process of determining the structural function can be automated by connecting a specialized block for measuring structural functions to the output of the detection block [12].

3. Monitoring of the water cut in single-phase oil-water flows

The density of a single-phase oil-water flow $\rho_{\text{mix}}$ can be expressed by the relationship

$$\rho_{\text{mix}} = \frac{\rho_w \cdot V_w + \rho_o \cdot V_o}{V},$$

(5)

where $\rho_w$, $\rho_o$ are the densities of water and oil, respectively; $V_w$ is the volume occupied by water; $V_o$ is the volume occupied by oil; $V = V_w + V_o$ is the total volume of the liquid phase.

The water cut of well products $W$ is determined as follows

$$W = \frac{V_w}{V}.$$ 

(6)

Substituting (2) in (1), we obtain

$$W = \frac{\rho_{\text{mix}} - \rho_o}{\rho_w - \rho_o}. $$

(7)

Proceeding from the above, knowing the density of oil and water and using the measured value of the density of liquid, the water cut in an oil-water flow can be determined.

3.1. Research results

Field tests of a radioisotope primary density converter were carried out at OJSC LUKOIL Usinskneftegaz by employees of the Mining University and “Complex-resource”, LLC in order to determine the possibility of its use for monitoring of the water cut in oil-water flows.

The tests included studies of the device’s sensitivity to a change in the chemical composition of the controlled medium, recording the device’s output signal from an actual oil-water flow and determining the water cut in the flow.

The study of the device’s sensitivity to a change in the chemical composition of the controlled medium was performed as follows. The controlled section of the pipeline was sequentially filled with tap water, formation water and oil, the density of which was previously measured by an oil density...
meter. In this case, the pulse counting rate at the output of the primary converter was measured and the coefficient of radiation attenuation by the medium $\mu$ normalized to the density was determined.

The device’s sensitivity to a change in the chemical composition of the controlled medium is characterized by a change in the coefficient $\mu$ when passing from one well product to another [13]. The measurement results are given in table 1.

| Analyzed environment | $\rho$, g/cm$^3$ | $N \cdot 10^3$, impulse/s | $\mu$, cm$^3$/g | $\frac{\mu - \mu_0}{\mu_0} \cdot 100$ | $N \cdot 10^3$, impulse/s |
|----------------------|------------------|--------------------------|-----------------|----------------------------------|--------------------------|
| Tap water            | 0.996            | 93.0                     | 0.76            | 0                                | 198.3                    |
| Formation water      | 1.091            | 88.0                     | 0.75            | -1.3                             | -                         |
| Oil                  | 0.853            | 102.6                    | 0.77            | +1.3                             |                           |

The deviation of the coefficient $\mu$ at a change in the chemical composition of the medium relative to the value, determined during the calibration, did not exceed 1.3%, while in the known radioisotope devices this value reaches 5%.

Figure 5 shows a schematic diagram of an experimental device, on which tests on an actual oil-water flow were carried out.

The oil-gas mixture from the well through the pipeline 1 was fed into the gas-separating tank 2, where it was settled for 14 hours. During this time, formation water, virtually free of oil, was concentrated in the lower part of the tank, an oil-water mixture – in the middle part of the tank, and almost pure oil – in the upper part of the tank. The mixture water cut along the tank height varied from 0.95 to 0.1.

The settled oil-water mixture was displaced from tank 2 by the product stream of a high-performance well with a high gas content through pipeline 4 with a diameter of 100 mm, coming out of the lower part of the tank. A radioisotope primary density converter 5 and a sampler 3 were installed on the horizontal section of the pipeline. In the process of displacing the oil-water mixture, the output signal of the density converter was recorded using an automatic potentiometer of the KSP type, and liquid samples were taken with a frequency of 5 min.

Figure 6 shows the nature of a change in the average density of an oil-water flow.

When processing the measurement results, the mixture water cut was derived from the following relationship
\[
W = (W_{\text{max}} - W_{\text{min}}) \frac{\ln \left( \frac{U_{\text{max}}}{U} \right)}{\ln \left( \frac{U_{\text{max}}}{U_{\text{min}}} \right)} + W_{\text{min}},
\]

where \(U_{\text{max}}, U_{\text{min}}\) are the values of the high signal at the maximum \(W_{\text{max}}\) and minimum \(W_{\text{min}}\) values of the mixture water cut; \(U\) is the current value of the output signal.

Relationship (8) was obtained taking into account that the output signal of the device is exponentially related to the average density.

Table 2 presents the results of laboratory analysis of mixture samples \(W_{\text{mix}}\) and calculated values of water cut \(W_{\text{calc}}\).

| Parameters | Time, \(t\), minute |
|------------|-------------------|
|            | 10    | 15    | 20    | 25    | 30    |
| \(W_{\text{calc}}\)    | 0.95  | 0.53  | 0.43  | 0.12  | 0.21  |
| \(W_{\text{mix}}\)    | 0.95  | 0.30  | 0.14  | 0.10  | 0.10  |

As a result of the unrepresentativeness of the samples, due to the location of the sampler in the upper part of the horizontal pipeline and irregularity in the distribution of the flow components over its cross section, the values \(W_{\text{mix}}\) are underestimated relative to the true value of water cut. At the same time, when the cross-section of the oil-water mixture flow is completely overlapped with a beam of gamma radiation, the error in measuring the water cut by a radioisotope primary density converter is due only to its sensitivity and a change in the chemical composition of the mixture as well as to instrumental error[14]. These components of the total error do not exceed 1.3 and 0.6%, respectively.

4. Conclusions

All field operations (drilling, production, pretreatment, storage, offloading, etc.) on Arctic shelf are performed on surface platforms of the following type: scaffold bridges with landing platforms; submerged platforms; floating semi-submerged platforms; artificial islands; stationary platforms; drilling and technological vessels [15]. Each type of surface platforms can be used in different environmental conditions. Each oil field has its own advantages and disadvantages. However, all field developments can use radioisotope methods of measurement and control. The advantage of the method is achieved due to the following: no preliminary separation and homogenization of the flow is required; no sensitivity to resin-paraffin deposits; operation is possible within a wide range of flow composition and velocities; no changes in flow parameters. Another advantage is the absence of restrictions on the physicochemical properties and the hydrodynamic structure of the flow.

Measured parameters include the following:
- density of an oil-gas mixture;
- free gas concentration in crude and commercial oil streams;
- water cut of an oil-water flow.

Experiments proved that the limiting value of the absolute error in measuring free gas concentration in commercial oil, using a radioisotope density converter, did not exceed 0.001 (1 liter of free gas per 1 m³ of oil).

The test results render it possible to conclude that an automatic in-line water cut meter can be developed on the basis of a radioisotope primary density converter, which allows performing in-process monitoring of the water cut of produced oil in a wide range with an error of at most 3%.
5. References

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