Bazhen Fm matured reservoir evaluation (West Siberia, Russia)

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Abstract. The depletion of the traditional sources of hydrocarbons leads to the situation when
the biggest players of the oil and gas production market turn to unconventional reserves.
Commercial shale oil and gas production levels in the USA have largely determined world
prospects for oil and gas industry development. Russia takes one of the leading place in
the world in terms of shale oil resources. The main source rock of the West Siberia, the biggest oil
and gas basin in Russia under development, the Bazhen Fm and its stratigraphic and lithologic
analogs, is located in the territory of over 1,000,000 square kilometers. Provided it has similar
key properties (organic carbon content, porosity, permeability) with the deposits of the Bakken
Fm and Green River Fm, USA, it is still extremely poorly described with laboratory methods.
We have performed the laboratory analysis of core samples from a well drilled in Bazhen Fm
deposits with matured organic matter (Tmax>435 °C). It was demonstrated the applicability of
the improved steady-state gas flow method to evaluate the permeability of nanopermeable
rocks. The role of natural fracturing in forming voids was determined that allows regarding
potential Bazhen Fm reservoirs as systems with dual porosity and dual permeability.

1. Introduction
The size of the West Siberian Basin, the largest oil and gas basin developed in Russia, is mainly
controlled by the deposits of the Bazhen Fm and the Abalak Fm underlying it (as well as their
stratigraphic and lithologic analogs) being the main source rocks of the region. The existing examples
of commercial oil development in Bazhen Fm reservoirs – despite the more than 55-year history of
studies for its oil-and-gas content (Galyanovskoe, Em-Egovskoe, Maslikhinskoe, Pravdinskoe,
Salymskoe, Sredne-Nazymskoe and other fields) – are inevitably accompanied by the shortage of
credible laboratory studies for petrophysical properties. The main reason for the latter is the
inadaptability of the existing equipment and methods of studying nanopermeable Bazhen deposits.
With the prevalent argillaceous-siliceous and argillaceous-carbonate composition, the thickness of the
Tithonian-Berriasian (some 150 million years ago) deposits in the Bazhen Fm varies from first meters
on the periphery of the Bazhen paleo-sea up to 60 meters at its depocenters. The total organic carbon
level in these deposits reaches 25 % [1] with the mean values being about 12 %. The studies of the
Bazhen reservoir quality have historically been localized by its productivity areas where oil influxes
were associated with abnormally high formation pressures with natural hydraulic fracturing, which also leads to the development of “bazhenit”, i.e. foliated shalestones that virtually fall to pieces in hands and do not allow using routine porosity and permeability evaluation methods. The pore volume of such rocks could be determined with the liquid saturation method with specific restrictions, but only well operation results, such as liquid flow rates or the calculated Kh value, were (and are still) used as a proxy indicator to evaluate permeability.

The target of the research was core samples from the wells drilled in Tomsk Region in an area characterized by the significant thermal heating on the Bazhen Fm deposits established by the value of the $T_{\text{max}}$ temperature being somewhat over 435 °C. In this study, we used about 20 meters of core (approximately 60 % of the thickness of the Bazhen Fm deposits in the area) being 80 meters in diameter from the depth of about 3 kilometers below sea level, which allowed to sample cylindrical core plugs 30 millimeters in diameter parallel to the bedding. The core from this well was mainly composed by silty silicites with clay matter (on average, 11 %) with the prevalence of illite in the latter.

2. Research methodology

The study used standard cylindrical core samples being 30 millimeters in diameter and also crushed samples being 2-5 millimeters in size. The application of crushed core to study shale/tight gas/oil reservoirs allowed significantly reducing the duration of preparatory procedures (extraction) and the study process itself down to practically acceptable values by increasing the specific surface of the sample [2]. Another benefit of the method using crushed core samples is the possibility to measure the permeability and porosity of matrix matter by excluding the impact of the natural fracturing of shaly rocks enhanced by the relief of lithostatic pressure during core sampling and its withdrawal to the surface. The samples (both cylindrical and crushed) were exposed to extraction with a spirits-benzol blend in a centrifugal extractor for 48 hours and subsequent drying at 105 °C for 16 hours. The samples were saturated with kerosene in two stages, including their vacuumization and resaturation under the pressure of 150 bars for 3+ days (this duration was determined experimentally).

The value of helium permeability in crushed samples was studied in normal conditions with a pressure decay method [3], where the curve of pressure drawdown in an operating chamber was approximated with a standard function the parameters of which were used to calculate permeability. The insignificant change in pressure during the test (on average, 0.5-2.0 % of the absolute value) places higher demands on instrument calibration, absence of leaks and thermal stabilization. The cycle of measurements with one sample is considered correct, if temperature changes during the test do not exceed 0.05 °C. The resulting experimental pressure drawdown curve is the superposition of pressure drawdown curves for grains with varying sizes and permeability values. The comparison of results provided by different installations can demonstrate a difference in permeability values by several orders. Another obvious drawback of the GRI (Gas Research Institute, USA) method is measurements in atmospheric conditions.

It is possible to overcome the above listed drawbacks by using the classical method of measuring gas permeability in reservoir thermobaric conditions with geometrized samples. Gas consumption stabilization during the use of standard core samples that are 45 millimeters high takes one week to several months, which makes such measurements technically unfeasible. Therefore we used samples being 30 millimeters in diameter and with a reduced height (5-20 millimeters vs. standard 45 millimeters), which allowed decreasing test duration down to 3-5 days. The pressure set on entry to the coreholder was 100-150 bars higher vs. reservoir pressure, and during the experiment the pressure was kept constant. The units of the filtration installation were thermostated during the experiment (figure 1).
Figure 1. Hydraulic installation scheme for measuring gas permeability in cylindrical samples in reservoir conditions under steady-state flow.

Gas is supplied to the coreholder from a vessel with a dividing piston, outlet pressure is maintained with a back pressure regulator. The volume of gas supplied to the system is registered on the basis of a pump piston position and recorded into a log file. In a steady-state (established on the basis of stabilization of differential pressure gauge indications), the consumption is compared using a gasometer. To determine the flow pattern and possibility to calculate permeability with the Darcy law, we checked the dependence of the steady pressure differential on a sample vs. gas filtration rate under constant effective pressure (figure 2). The test was performed under changes in pressure on entry to the coreholder.

Figure 2. Steady gas consumption dynamics under differential gas pressure changes during tests.

The consumption of gas measured with the gasometer is corrected with due account for the difference in pressures/temperatures and compared with the indicators of the plunger pump. The difference in consumptions allows determining the value of a leak. For a steady-state filtration area,
the values are approximated with a straight-line correlation the slope of which characterizes the established consumption through the sample under test (figure 3).

![Graph showing dynamics of gas volume pumped through the sample.](image)

**Figure 3.** Dynamics of gas volume pumped through the sample.

The porosity of cylindrical samples and crushed samples was determined with the liquid saturation method (kerosene) with sequential weighting.

3. **Research findings**

The values of gas permeability measured in reservoir conditions in cylindrical samples significantly exceed the values of gas permeability in crushed samples determined with the GRI method (figure 4). At the same time, the GRI permeability corresponding to the permeability of a rock matrix without microfractures demonstrates relative constancy and varies within $0.051 \cdot 10^{-9}$ mkm$^2$ to $0.208 \cdot 10^{-9}$ mkm. The permeability of cylindrical samples varies within an extremely wide range, which apparently characterizes the properties of the fracture space not collapsing completely even when overburden pressure is exerted [4]. The study of the overwhelming majority of the petrographic thin sections oriented perpendicularly the bedding demonstrated the presence of discontinuous and continuous fractures of different morphology with an aperture making 0.01 to 0.40 mm (figure 5).
The values of effective porosity measured in crushed and cylindrical samples demonstrate analogous correlations (Figure 6), which is also regarded as the comparative characteristic of different types (pore and fracture) of voids.
Figure 5. Microphoto of a petrographic thin section (field-of-view width – 1.74 mm). Pyritized silty silicite enriched with organic matter. The aperture of the fractures developed both in parallel to and across the foliation surface equals 0.015 mm.

Figure 6. Distribution of kerosene porosity measured in different samples.
4. Conclusion
The present study has revealed the possibility to measure permeability in nanopermeable samples in reservoir conditions under steady-state gas filtration. For the overall section, the permeability of cylindrical samples exceeds matrix permeability by the factor of $10^{1-10^6}$, which is explained by the presence of fractures that are abundantly diagnosed in petrographic thin sections and visible to unaided eye in core plugs. The reservoir properties (and especially permeability) of the Bazhen Fm deposits is largely determined by the presence and geometry of natural fracturing. The study of this parameter that is apparently an effective pressure function should be performed under different values of overburden pressure with the steady-state gas or liquid filtration method. The research findings confirm observations about the productivity of the fractured and cavernous fractured reservoir at the Bazhen and Abalak Fm that have frequently been mentioned earlier.

References

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