

DEPÓSITO LEGAL ppi 201502ZU4666
*Esta publicación científica en formato digital
es continuidad de la revista impresa*
ISSN 0041-8811
DEPÓSITO LEGAL pp 76-654

Revista de la Universidad del Zulia

Fundada en 1947
por el Dr. Jesús Enrique Lossada



Ciencias del

Agro

Ingeniería

y Tecnología

Año 11 N° 29

Enero - Abril 2020

Tercera Época

Maracaibo-Venezuela

Determination of the reasons for the lower injectivity of the injection wells

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ABSTRACT

The injection of water into the formations to maintain their pressure is accompanied by loss of injectivity in the injection wells. It is necessary to determine the reasons for the loss of injectivity to apply various methods of regulation of the characteristics of the filtration tank in the area of the bottom of the formation, which will allow to restore the injectivity of the wells and increase the coverage of the formation by flooding. of water. The document presents the results of the determination of the alleged causes of a loss of injection well injection, the hypotheses to determine the causes of a loss of injection and the studies conducted to confirm or refute the causes mentioned.

KEY WORDS: Loss of injectivity, change in the salinity of the injected water, dilation of clay and rock particles.

Determinación de las razones para la menor inyectividad de los pozos de inyección

RESUMEN

La inyección de agua en las formaciones para mantener la presión de estas, se acompaña de pérdida de inyectividad en los pozos de inyección. Es necesario determinar las razones de la pérdida de inyectividad para aplicar varios métodos de regulación de las características del depósito de filtración en la zona del fondo de la formación, lo que permitirá restaurar la inyectividad de los pozos y aumentar la cobertura de la formación por inundación de agua. El documento presenta los resultados de la determinación de las supuestas causas de una pérdida de inyectividad de pozos de inyección, las hipótesis destinadas a determinar las causas de una pérdida de inyectividad y los estudios realizados para confirmar o refutar las causas mencionadas.

PALABRAS CLAVE: Pérdida de inyectividad, cambio en la salinidad del agua inyectada, dilatación de partículas de arcilla y roca.

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Recibido: 07/01/2020

Aceptado: 12/02/2020

Introduction

Currently, when productive formations of large deposits have been significantly mined, commissioning of small deposits remote from areas of developed infrastructure is becoming very important. The commissioning of such deposits may be accompanied by a number of uncertainties and risks of non-conformity to estimated production and injection values (Pesotsky & Perovsky, 2015; Alvard et al., 2001; Alvard & Tokarev, 2002; Ahmadov, 2019). So, when commissioning one of the fields in Western Siberia, the problem of maintaining formation pressure became acute. The field in question is located in the Nizhnevartovsk region, it belongs to the category of small deposits and is located at a distance of 10.2 km from the nearest deposit.

The exploited object UV₁ is represented by terrigenous reservoirs with a permeability of $8,5 \cdot 10^{-3} \mu\text{m}^2$ (the petrophysical dependence of a neighboring field was used to evaluate permeability, no own studies are available), porosity of 17% and initial formation pressure of 25,8 MPa.

As on 01.01.2019, 20 wells were drilled at the facility, 2 wells were transferred for injection. It should be noted that in order to maintain formation pressure, intra-cluster injection from a water well was organized, since it was less efficient to extend a 10 km high-pressure water conduit from a neighboring field for the pressure maintenance system.

When operating injection wells at the facility, an abnormal injectivity loss was registered with decrease from 150-200 m³ / day to 40-50 m³ / day in the first months of operation. Fig. 1 shows the operating modes of injection wells.

Total injectivity loss and, accordingly, the water flow rate in the well below 100 m³ / day leads to a supply interruption, pump overheating and shutdown of the injection wells (the water well is equipped with an ECN-200 pump).

The article describes the suggested hypotheses, aimed at identifying the causes of injectivity loss, and studies conducted to confirm / refute them.



Injectivity, water flow rate, m³/day
Start of injection well №1
Start of injection well №2
Pump operating range 150-270 m³/day
Total injectivity
Date

Fig. 1. Operating modes of injection wells

The first hypothesis was put forward on the possible mudding of the bottomhole formation zone by reaction products of deposit and injected water, or by mechanical impurities. A description of the process of mudding and methods for its elimination is reflected in papers (Kuznetsov & Muzipov. 2010; Zakharova et al., 2016).

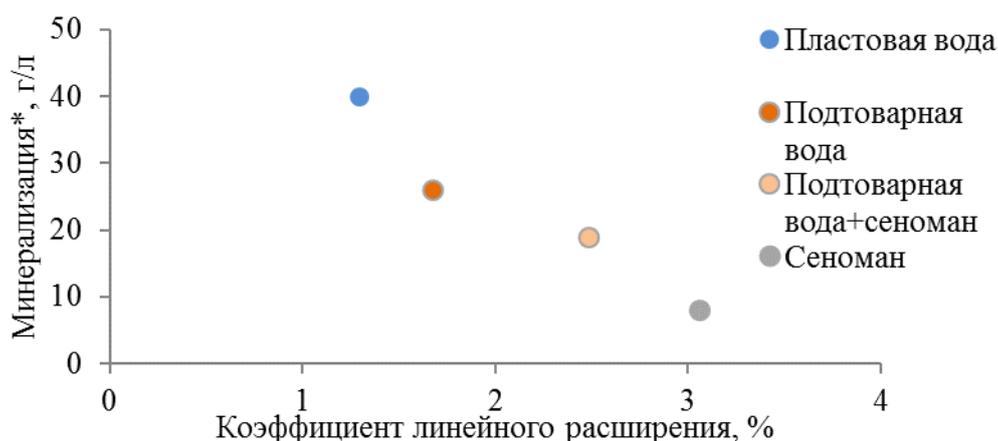
To test the hypothesis, samples of deposit and injected water were taken from the wells of the described object. The content of mechanical impurities in the samples of injected water was 3 mg / l (the limit of the content of mechanical impurities for reservoirs with a permeability of less than 0,1 μm^2 is 3 mg / l, which corresponds to the regulation OST 39-255-88 «Water for flooding of oil reservoirs. Quality requirements»).

Calculations for water compatibility were performed analytically based on an analysis of the water chemical compositions. For calculations, the specialized programs “CARBON” (Debye-Hückel method) and “ROSA” were used. According to the results of the assessment, it was found that the mixing of deposit and injected water in any proportions does not lead to precipitation in a volume exceeding the limit value in accordance with the requirements of OST standard (carbonate and calcium sulfate fall out in the amount from 0,013 mg / l to 0,77 mg / l).

According to the results of the analysis, the hypothesis on mudding of the bottomhole formation zone of injection wells was rejected due to its insolvency.

Next, a hypothesis was suggested about the possible dilatation of rock clay particles and a decrease in permeability in the bottomhole formation zone. The works (Kozhevnikov, 2016; Tang & Morrow, 2002; Stupochenko & Avanesov, 1991; Goldberg & Skvortsov, 1986; Mirchink et al., 1975; Kibalenko & Stupochenko, 1992; Buckley & Morrow, 2011), describe the process of reducing the injectivity of injection wells while reducing the salinity of the injected water.

To test the above hypothesis, core studies were planned and carried out on rock dilatation during the injection of water samples with various salinity. As the test solutions, there were used formation and bottom water, as well as a mixture of bottom and Alt-Alb water of the Cenomanian aquifer complex (AASVK). The results of the study of the samples are presented in Fig. 2.



Salinity*, g/l

- Formation water
- Bottom water
- Bottom + Cenomanian water
- Cenomanian water

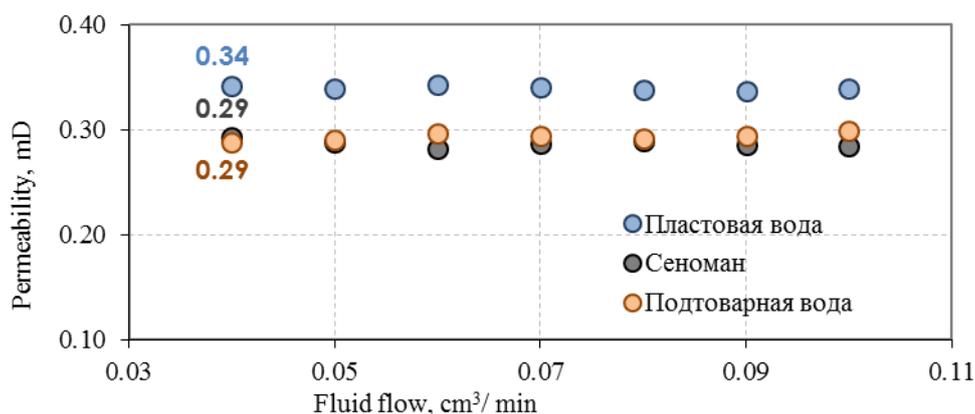
Expansion coefficient, %

Fig. 2. Dilatation of core samples during the injection of water samples with various salinity

With a decrease in salinity of water injected into the formation, clay dilatation is observed (a change in the coefficient of linear expansion is equivalent to a change in pore volume). According to the results of studies, the maximum dilatation of the rock / decrease in porosity can be achieved with the injection of Cenomanian water and will equal 2%.

During the second stage of research (for direct determination of permeability), a series of injections was carried out with a sequential decrease and then an increase in salinity (formation - Cenomanian - bottom) to assess the possible restoration of permeability and the subsequent decision to change the injection agent.

According to the results of studies, a change in salinity does not significantly affect the decrease in permeability and mobility. The decrease was 13,7% and 7,4%, respectively. The research results are shown in Fig. 3. With an increase in the salinity of the injected water, permeability recovery was not observed.



- formation water
- Cenomanian
- bottom water

Fig. 3. The dependence of the various water permeability on fluid flow (example for one sample)

Alongside with core research, an efficiency record was taken in one of the studied injection wells (studies were already conducted at the well during the period of production work).

Due to the fact that there is no clear exit to the radial mode (despite the long duration of the study, relative to the study in production at the same well), the

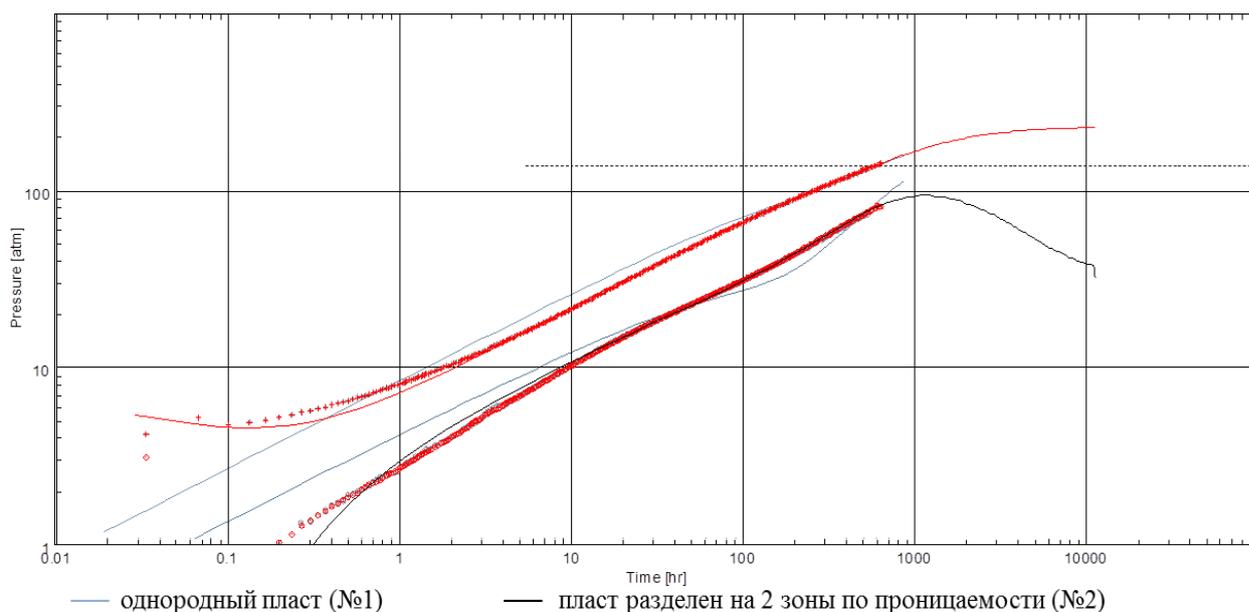
parameters obtained as a result of the interpretation can be considered as estimated figures, and the reliability of the study can be considered low.

The classical interpretation of the study (the accepted model of the well is a fracture with finite conductivity, a homogeneous formation, intersecting faults) does not provide acceptable convergence of actual and calculated data, therefore, a model of a radial composite formation was chosen for interpretation.

The selected model best describes the flows between the zone of low reservoir properties in the bottomhole formation zone and the zone of improved reservoir properties in the remote part of the formation. Fig. 4 and table 1 show the results of efficiency studies and comparison with the standard interpretation.

Table 1. Well test results for various options

Properties	Interpretation variant №1 – homogeneous formation	Interpretation variant №2 – formation is divided into 2 zones with various permeability
Formation	homogeneous	radial composite
Boundaries	intersecting faults	Infinite boundaries
Skin factor	-6.35	-6.05
Xf, m	125	124
Pi, atm	102.4	173.3
L1- non-permeable, m	32	-
L2- non-permeable, m	340	-
k*h, mD*m	1.45	2.07
k, mD	0.05	0.064 (closer zone) 0.233 (remote zone)
R of degraded zone, m	-	125



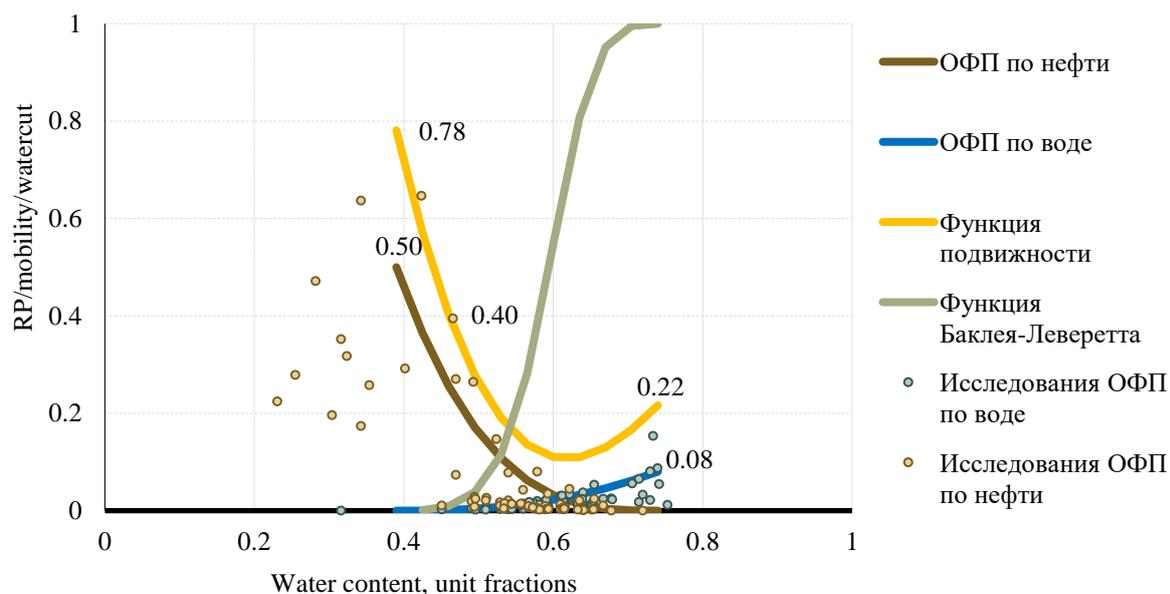
- homogeneous formation
- formation is divided into 2 zones with various permeability

Fig.4. Results of efficiency studies on injection well (diagnostic chart for different interpretations)

The radius of degraded zone was 125 m (the minimum value, it could increase with a longer study duration). According to the research results, the permeability in the degraded zone is 0,064 mD, permeability in the rest formation area 0,233 mD, a decrease equals 3,6 times.

The presence of a zone with degraded properties can be associated with both dilatation of the rock (the hypothesis is not confirmed by core studies) and degraded water permeability and hydrophilicity of the rock (natural causes) and can be partially described by the RP functions obtained in neighboring fields (Fig. 5).

Core studies conducted in October 2018 speak in favor of the assumption on RP deterioration. The porosity - permeability relationship significantly deviates from that adopted by analogues (2-3 times lower with average parameters). The results are shown in table 2.



RP to oil
 RP to water
 Mobility function
 Buckley-Leverett function
 Studies of RP to water
 Studies of RP to oil

Fig. 5 Type of RP functions characteristic of UV₁ reservoirs (according to the analogic field)

Table 2. Core permeability assessment

Well №	Cpor, %	Relative permeability assessment, mD		Cperm (own data) / Cperm analogue, unit
		Analogic field	Own data	
1	13.1	1.9	1.2	1.5
2*	15.2	7.9	2.8	2.9
3*	14.6	5.7	2.3	2.6
4	15.8	11.1	3.4	3.2
5	15.5	9.9	3.1	3.1
6	15.5	9.6	3.1	3.1
7	16.0	17.5	4.3	4.1
8	14.9	6.1	2.4	2.6

9	14.6	5.1	2.1	2.4
10	15.4	8.7	2.9	3.0
11	15.5	9.9	3.2	3.1
Average	15.1	8.5	2.8	3.0

Note* - injection wells

To confirm the hypothesis of degraded reservoir properties, an analytical assessment of the well flow rate dynamics was performed during the period of work in production and injection.

For the calculations, the inflow equation for an unsteady operating mode (Basniev et al., 1993), was used (the calculations were performed in the corporate form for calculating the production rates of new wells taking into account the formation saturation and phase mobility, hydrophilic RPs from the analogic field were used):

$$q = 2\pi \frac{kh(\bar{P} - P_{wf})}{\mu B \left(\ln \left(\frac{kt}{\phi \mu c_t r_w^2} \right) + S \right)}$$

Where k – formation permeability;

h – net thickness;

\bar{P} – formation pressure;

P_{wf} – bottomhole pressure;

t – well operation time;

ϕ – porosity;

c_t – compressibility of pore volume;

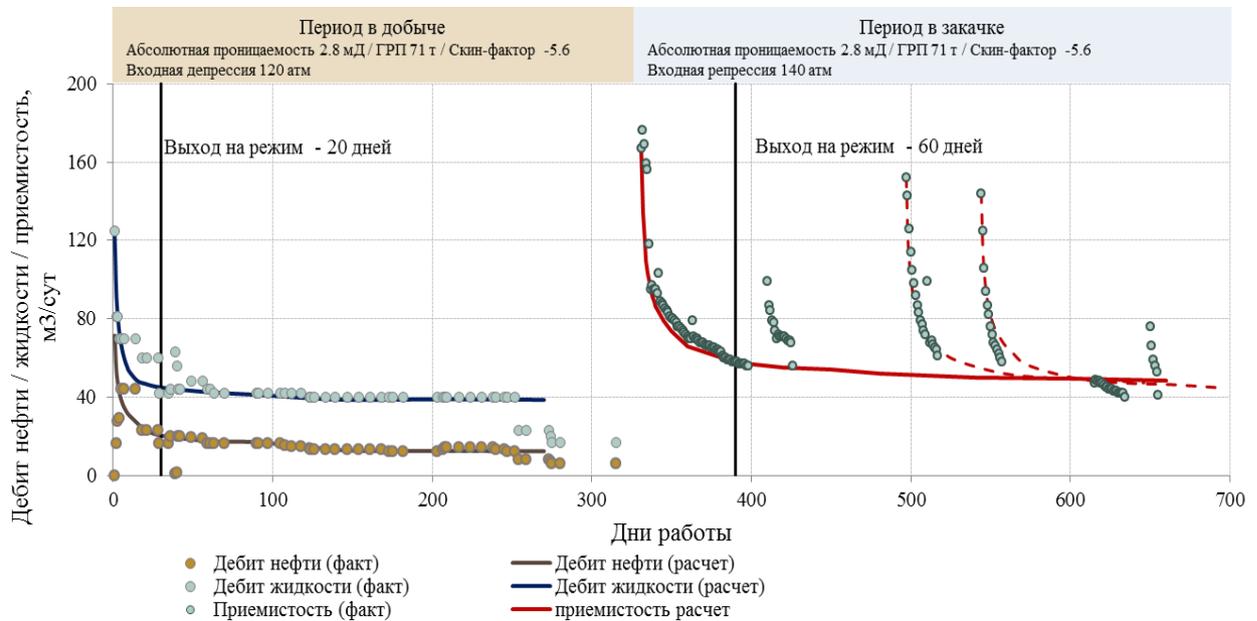
r_w – well radius;

S – skin factor.

Analytical calculations show that with a changed permeability, a decrease in injectivity can be caused by a long response time of a well (a steady-state operation can be reached after 2-3 months of operation, Fig. 6), while the well's response time in production is much lower and equals 20 days. The injectivity of injection wells at a steady operating mode will be 40-50 m³ / day.

According to the results obtained, a short-term work program has been developed, the main purpose of which is to confirm a new hypothesis (time for the well to reach steady-state operation). To do this, it is planned to put shutdown injection

wells into operation, change the pump in the water well to a less productive one (ECN-100), monitor the operation of injection wells in the first 4 months of work, and subsequently conduct flow test after the first months of work.



Oil rate/water rate/injectivity, m³/day

Production period

Absolute permeability 2,8 mD/ FHF 71t/ Skin-factor -5,6

Incoming pressure-sink 120 atm

Response time 20 days

Injection period

Absolute permeability 2,8 mD/ FHF 71t/ Skin-factor -5,6

Incoming overbalance 140 atm

Response time 60 days

Operation days

Oil rate (actual) – oil rate (calculated)

Water rate (actual) – water rate (calculated)

Injectivity (actual) – injectivity (calculated)

Fig. 6. Analytical calculation of the injection well performance with account to the updated RP

Conclusion

In 2018 a series of research works has been carried out aimed at identifying the reasons for the injectivity loss of injection wells. The most likely cause is the low formation permeability and hydrophilicity of the reservoir, leading to a decrease in mobility when transferring wells for injection.

Based on the research findings it should be noted that:

- Change of the injection agent from the water of the AASVK group formations to bottom water is impractical.

It is necessary to consider the possibility of intensifying the injection using the following types of measures: bottom hole treatment, hydraulic fracturing, the installation of surface booster systems that allow implementing the auto hydraulic fracturing mode.

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