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DIAGNOSIS OF ATYPICAL WATER INJECTION MECHANISMS FOR PRODUCTION SYSTEM INTEGRITY MANAGEMENT: A CASE STUDY OF X FIELD

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Abstract:
In the absence of a reservoir pressure maintenance (RPM) system at Field X, a critical increase in water cut to 92.6% has been observed, with current production at 72.4% of the initial recoverable oil reserves. Such a high water cut at a stage that does not correspond to full production suggests the presence of atypical mechanisms. This study aimed to comprehensively analyze the causes of the abnormal water cut using modern diagnostic methods, including geophysical well logging (GWL), reservoir pressure monitoring, hydrogeochemical analysis of associated waters and detailed laboratory studies of core samples. The analysis revealed that the primary cause is a man-made breach in the production column of Well #4, resulting in the overflow of highly mineralized water from the overlying Albian-Cenomanian aquifer into the productive J-XI formation. Petrophysical studies revealed high reservoir heterogeneity. However, the oil displacement coefficient by water was 0.53 for highly permeable formations, ruling out low oil recovery as the main cause of water flooding. Key evidence of the human-made nature of the problem includes the abnormal increase in reservoir pressure, from 23.9 MPa in 2022 to 25.5 MPa in 2023, as well as the presence of sulphate ions in the production water, which is characteristic of the Albian-Cenomanian complex. A set of practical recommendations has been developed, including the urgent repair and insulation of Well #4, the introduction of a casing integrity monitoring system and the adaptation of the development strategy. The results emphasize the importance of monitoring the technical condition of the well fleet to ensure the effective late-stage development of similar fields. The study demonstrates that integrating this diagnostic methodology into a production management system enables proactive risk mitigation, supports decision-making for well intervention, and contributes to optimizing the overall production strategy in mature fields.

Key words: water ingress, man-made factors, crossflows, production column, geophysical studies, hydrogeochemistry, core studies, formation pressure, production management, operational risk, decision-support system, integrated asset management

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INTRODUCTION

High water cut in oil wells is one of the most significant issues in modern oil production. On average, a significant proportion of energy resources are spent worldwide on maintaining production at high water cut. For instance, approximately 13.3% of all electricity produced in the Russian Federation in 2019 was used for this purpose [1]. This issue is particularly pertinent in Kazakhstan, where many fields are in the late stages of development. In fields such as Tengri and Uzen, water cut can reach 80-90% or more and the proportion of hard-to-recover reserves can exceed 50% of total reserves. This leads to a significant increase in energy costs for production preparation and a decrease in economic efficiency, which is particularly noticeable in the absence of reservoir pressure maintenance systems [1, 5]. Waterflooding of production wells is a natural process in oil field development, but unusually high rates of waterflooding often indicate unaccounted geological or human factors [2, 3]. At the late stage of reservoir development, water cut becomes a determining factor affecting both the ultimate oil recovery factor (UORF) and the economic viability of continuing to exploit the field.

The presented case allows the identified process to be classified as an atypical technogenic mechanism of water injection. This is fundamentally different from classical waterflooding scenarios such as bottom-water coning, edge-water encroachment, or breakthrough from injection wells. Unlike traditional mechanisms, which are driven by planned reservoir pressure maintenance (RPM) systems or natural aquifer support, the water influx at Field X is caused by a localized loss of well integrity. This results in uncontrolled hydraulic communication between an overpressured external aquifer and the producing formation.

In this scenario, the defective production casing of Well #4 has turned the well into an unintended injection conduit, effectively creating a pseudo-reservoir pressure maintenance system (“uncontrolled RPM”). The Albian-Cenomanian aquifer, characterized by higher formation pressure, acts as an active water source, continuously injecting highly mineralized water into the J-XI reservoir. Consequently, the reservoir exhibits anomalous hydrodynamic behavior, including local pressure growth and redistribution, despite the complete absence of a formal RPM system.

This mechanism differs critically from classical waterflooding processes in both its driving force and spatial manifestation. While conventional water breakthrough is usually linked to gradual frontal advance or coning under declining pressure conditions, the technogenic crossflow identified here generates point-source water injection, sharp pressure gradients and rapid water cut escalation. These features confirm that the observed water ingress represents a distinct class of anthropogenic water injection mechanisms requiring dedicated diagnostic criteria and management approaches.

Atypically high rates of water ingress may be associated with man-made causes, including failure of wellbore integrity. One of the key indicators of system failure is steady casing pressure (SCP), which can indicate defects in the column or cement stone [3]. SCP problems have been recorded in over 45% of Gulf of Mexico wells, with corrosion, gas migration, and degradation of the casing string and cement stone being among the likely causes [4]. Effective water flow control (WFC) requires the correct diagnosis of the mechanism of water ingress. In particular, it is necessary to determine whether it is caused by water breakthrough from injection wells or cone formation of bottom water [2].

Traditionally, increased water content has been linked to the operation of RPM systems and the breakthrough of bottom or edge waters. It has also been associated with the filtration capacity properties (FCP) of reservoirs [5]. Casing and cement failures account for over 90% of all incidents involving loss of well integrity [6]. However, cases of atypical water ingress caused by man-made breaches in the integrity of well equipment, including the depressurization of the casing string and cement ring, are being recorded more frequently worldwide [5]. A breach in the integrity of the cement shell (cement stone) is particularly critical as it can lead to microannuluses forming, as well as radial cracks, shear failures and debonding. These serve as highly permeable leakage channels [1, 6]. Mechanisms associated with flows through the annular space or through casing defects are particularly challenging to diagnose and necessitate a thorough approach, encompassing the analysis of annular pressures, thermohydrodynamic con-

ditions, and the condition of the casing. One key manifestation of depressurization is steady casing pressure (SCP), which arises from the discrepancy between the limited volume of the closed annular space and the thermal expansion of the fluid resulting from changes in the temperature field within the well [7]. This problem is commonly encountered in deepwater and high-temperature wells. For instance, SCP was recorded in over 45% of cases in wells in the Gulf of Mexico [5, 7]. Diagnosis requires a comprehensive approach and includes analysis of annular pressures and thermohydrodynamic conditions. Modern monitoring technologies, such as distributed acoustic (DAS) and temperature (DTS) sensors, as well as multi-finger calipers, are used to detect leaks early and assess the condition of the casing [6]. Scenarios involving uncontrolled flooding lead to significant economic losses and the premature decommissioning of wells. Premature decommissioning due to integrity failures reduces the actual service life of wells from their design life of 30-50 years to just 7-25 years, resulting in significant financial losses [5, 6]. This study is relevant due to the increasing frequency of man-made water ingress at the late stage of field development, when an increase in water saturation is combined with a deterioration in the geomechanical condition of the bottom-hole zone. To improve reinforcement quality during construction and eliminate the contraction effect that contributes to filtration channel formation, cementing slurries should be modified with carbon additives such as carbon black, graphite, graphene oxide or carbon nanotubes. These improve pore structure and cement stone durability [8]. This work is particularly relevant when a RPM system is absent and traditional watering mechanisms cannot satisfactorily explain the observed anomalies. In such cases, it is necessary to consider the impact of human interference with the integrity of the wellbore [9, 10]. Corrosion-related failures account for over 25% of failures in the oil and gas industry, often resulting in breaches to the integrity of the well barrier shell and leading to hydrocarbon leaks or the discharge of chemical reagents into underground aquifers. Traditional well integrity monitoring programs, such as wellbore temperature studies and annulus surveys, usually detect breaches in casing integrity after a defect has already occurred in the well barrier system. Barrier shell breaches and loss of well integrity are common: according to various studies, approximately 2.6-6.3% of analyzed wells have such breaches, while the proportion of offshore wells with sustained casing pressure (SCP) can reach 11-12%.

The study aims to identify and describe specific (atypical) waterflooding mechanisms at Field X. In the absence of a Reservoir Pressure Maintenance System (PPS), a critical water cut of 92.6% was recorded when 72.4% of the initial recoverable oil reserves had been produced. This finding was based on a comprehensive analysis of geological and man-made factors, including GIS interpretation, reservoir pressure monitoring, hydrogeochemical analysis of associated waters and laboratory core studies. The study also developed practical recommendations for reducing water cut and optimizing the field's further development strategy. Although a technical diagnosis is essential, this study primarily aims to demonstrate how such subsurface anomalies lead to systemic production management challenges. Field X is used as a case study to develop a framework for integrating subsurface diagnostics into operational decision-making and risk management systems. The study specifically aims to: identify the atypical water injection mechanism; quantify its impact on the overall production system's performance and efficiency; and propose a structured approach for incorporating well integrity and reservoir surveillance data into production management protocols to prevent similar systemic failures in mature assets.

MATERIALS AND METHODS OF RESEARCH

The X deposit is located within the South Mangystau oil and gas region. The productive J-XI horizon is confined to the Aalenian deposits of the Middle Jurassic and lies at depths of 2,400-2,470 meters. The reservoir is composed of terrigenous rocks, predominantly fine-grained sandstones cemented by clay. The regional cap is formed by 19.8 m thick carbonate-clay rocks of the Bayos stage. The overlying Albian-Cenomanian aquifer complex, located at a depth of ~1100 m, is characterized by high formation pressure (the piezometric level is higher than that of the productive Jurassic) and high-water mineralization (up to 180 g/l).

The following modern methods were used to solve the tasks:

1. Analysis of historical production data. Firstly, historical production data from 2010 to 2024 was analyzed and dynamic curves were constructed to identify anomalies in well behavior and water cut rates [12]. Graphs of oil, liquid and water production dynamics were constructed in MS Excel, as was statistical data processing. This made it possible to identify the "inflection point" on the water production curve and establish its correlation with the start of Well #4 active operation.

2. Analysis of well logging data (WLD). This analysis focused on assessing the integrity of the production column and was key for diagnostics. The study examined research into determining the tightness of columns (CLT), as well as current data on Well #4. Diagrams were interpreted to determine working intervals and identify channels behind the column. This was performed using specialized WLD interpretation software "Techlog", which made it possible to accurately identify the interval of integrity failure and correlate it with the geological section. This interval was then correlated with the sections in order to establish its connection with the Albian-Cenomanian aquifer complex [13].

3. Regularly monitor formation pressure. This is organized to assess the hydrodynamic conditions in the formation. High-precision measurements were carried out at the bottom of key production wells (#1, 4, 8, 14, 15, 20 and 21) using "PDD-6K" and "Kvant-M" electronic depth pressure gauges. Subsequent data processing, including statistical analysis, reduction to a single plane, calculation of gradients, and construction of isobar maps to analyze the spatial and temporal distribution of pressure, was carried out using Petrel software packages [14].

4. Hydrogeochemical analysis of associated waters. The most important part of the study was the hydrogeochemical analysis of associated waters. This was aimed at identifying the source of waterlogging by comparing the ionic composition with reference samples. This research was conducted in accordance with GOST 26449.1-85, which outlines methods for the chemical analysis of saline waters and their primary components. The ionic composition (Na^+, K^+, Ca^{2+}, Mg^{2+}, Cl^-, SO_4^{2-} and HCO_3^-) and total mineralization were determined using modern analytical methods. Atomic emission spectrometry was used to analyze the cations, and ion chromatography was used to analyze the anions. Particular attention was paid to determining sulphate ions by gravimetry, which involved precipitating them from a hot hydrochloric acid solution with barium chloride, followed by calcining and weighing the resulting barium sulphate precipitate. The carbonates and hydrocarbonates were determined using sequential acidimetric titration with phenolphthalein and methyl orange as indicators. Calcium was titrated in an alkaline medium (pH 12) using a solution of Trilon B and Murexide, while magnesium was determined by complexometric titration in the presence of an ammonium-ammonia buffer solution (pH 9-10) with a black chromogen. Chlorides were analyzed by mercurimetric titration using a nitric acid-mercury solution with diphenylcarbazone. The pH value was determined using an electrometric method with a glass electrode and a laboratory pH meter in the range 1.00-12.00. Total hardness, caused by the presence of calcium and magnesium salts, was determined by eliminating the influence of other elements: triethanolamine was added to eliminate the influence of iron and aluminum; sodium sulphide was added to eliminate the influence of nickel, copper and zinc; and hydroxylamine hydrochloride was added to eliminate the influence of manganese.

Based on the obtained data, key diagnostic coefficients (rNa/rCl, rCa/rMg and SO_4^{2-}/Cl^-) were calculated. This made it possible to determine the water's genetic origin and identify its source. All analytical work was performed using standard laboratory equipment, including a chromatograph, a spectrometer, titrators and laboratory pH meters [15, 19].

5. Laboratory core testing. This was conducted to comprehensively assess the filtration and displacement capacities of the reservoir [16]. Core samples from the J-XI horizon of Well #4 were tested using standard methods (GOST 26450.2-85). Under reservoir conditions (65°C, 25 MPa), the absolute open porosity and air permeability were determined using a UIK-3 device. Capillary pressure curves were recorded on a capillary rig using the semi-permeable membrane method. Relative phase permeabilities for the oil-water system were determined on an LXRT-400T filtration rig.

6. A petrographic study of thin sections was performed using optical microscopy to characterize the lithology and mineralogy of the reservoir, which is necessary to understand the reasons for its heterogeneity [17]. The lithological composition, grain size and roundness, cement type, porosity and secondary changes were analyzed using an Axio Imager A2m polarization microscope (Carl Zeiss), which was equipped with a digital camera.

RESULTS AND DISCUSSION

Analysis of historical production data

Analysis of the historical dynamics of key technological indicators (Fig. 1) revealed classic signs of abnormal water ingress.

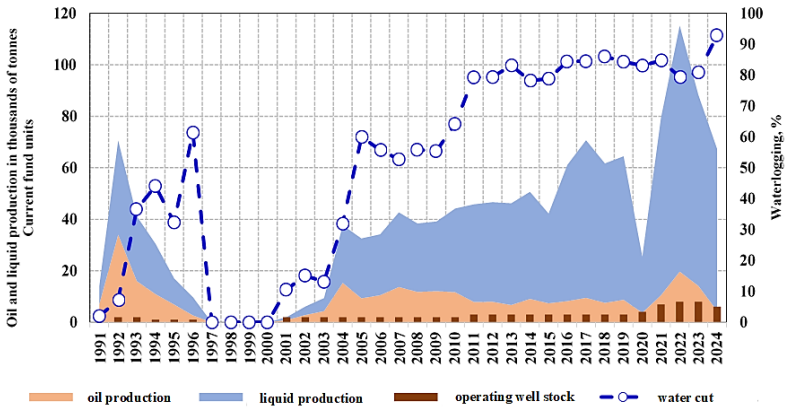


Fig. 1 Dynamics of oil, liquid and water cut production at Field X from 2010 to 2024

Alt text: *line graph showing declining oil production, increasing total liquid production, and a sharp rise in water cut after 2015, exceeding 90% by 2024.*

The oil production curve shows a steady decline from 125,000 tonnes in 2010 to 15,000 tonnes in 2024. Conversely, the liquid production curve shows an abnormal increase from 150,000 m³ to 280,000 m³ during this period.

The graph clearly shows a “bend” in the water saturation curve between 2015 and 2016, after which the growth becomes exponential. This temporary coincidence with the start of the active exploitation of Well #4 is the first key indicator of the human-made nature of the problem. In the absence of a formation pressure maintenance system (RPM), the divergence between declining oil production trends and growing fluid production trends clearly indicates the entry of an external agent into the formation.

The oil production curve has shown a steady downward trend since development began. Peak production values occurred in the early years, followed by a sharp decline and a subsequent gradual decline to minimum values by 2024. This indicates the intensive depletion of reserves.

In contrast, the liquid production curve shows growth throughout most of the period, particularly after 2015-16. This divergence is a classic sign of increasing water cut.

The water saturation curve clearly illustrates the field's main problem. It begins with low values (less than 10-20%), which are typical of the early stage. This is followed by exponential growth, which has led to a critical level of over 90% in the most recent years of observation. The steepness of the curve between 2015 and 2016 confirms the unusual and intense nature of the water saturation, which is not associated with traditional flooding.

1. Technogenic cause: violation of the integrity of the production column in Well #4. The most pronounced and well-documented cause is a defect in the production column in Well #4. 4. Geophysical survey data (WLD) from 30 June 2014 clearly indicate a breach in the 1100.4-1103.0-meter interval. Around 25% of all extracted fluid enters the productive part of the J-XI horizon through this defective channel (Table 1). In fact, Well #4 acts as an unauthorized injection well, injecting water from the Albian

horizons of the Cretaceous system into the main productive formation for which it is not intended (Fig. 2).

Table 1

Results of WLD column leak detection

No.	Horizon	Perforation Intervals	Type of research	WLD data	Device income, m	Operating intervals	Wear, %
4	J-XI	2437-2444	CLT	30.06.2014	2463	1100.4-1103 2437-2438.6 2439.8-2441.4 2442.2-2448	25 7 5 63

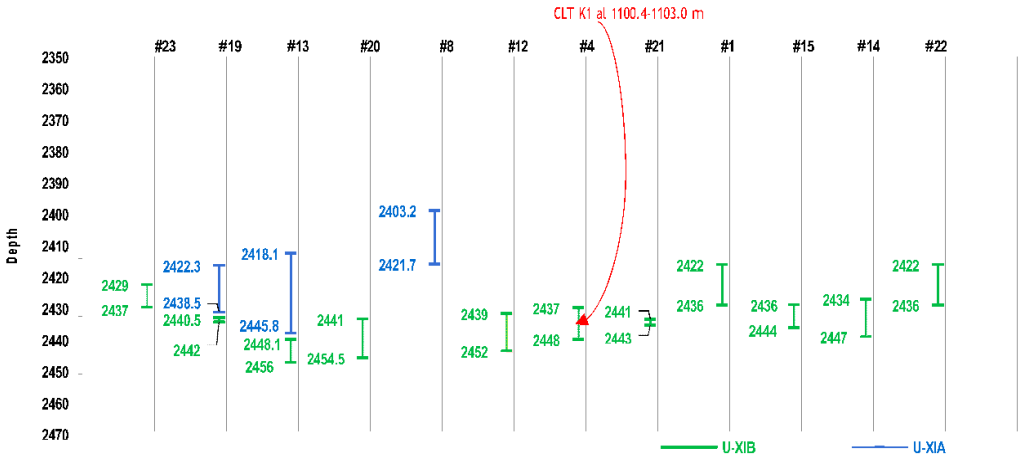


Fig. 2 Schematic model of water flow from the Albian horizon to the productive J-XI formation via a defect in the production column of Well #4*

**The 1100.4-1103.0 m interval corresponds geometrically to the contact zone with the Albian-Cenomanian aquifer complex. Flow meter data confirms fluid inflow in this interval, proving its role as a flow channel.*

Alt text: *schematic cross-section showing water flowing from the Albian-Cenomanian aquifer through a casing defect in Well #4 into the productive J-XI reservoir.*

This not only floods the well itself, but also creates an area of increased pressure in the formation. This changes the direction of the filtration flows, diverting the flow of water from the well into the formation. This not only floods the well itself, but also creates a zone of increased pressure in the formation. This causes a change in the direction of filtration flows, resulting in the flooding of neighboring production wells. Thus, a single technically faulty well can have a negative impact on the entire field development system.

This case clearly illustrates a critical principle in production system management: the failure of a single component (Well #4) can result in performance degradation at the system level. Uncontrolled crossflow acts as an unplanned "injection node," disrupting the field's natural depletion strategy. This results in several management failures, including inefficient energy expenditure on lifting and processing enormous volumes of extraneous water, an accelerated decline in neighboring wells due to altered flow paths and a significant increase in operational risk associated with rising formation pressures. The economic impact extends beyond lost oil production to include increased operating expenses (OPEX) and potential capital costs for premature well workovers.

Formation pressure monitoring

Before each measurement, the wells were stabilized to achieve a steady-state filtration regime. The wells were shut down for a period of 24 to 72 hours to allow the formation pressure at the bottom hole to fully recover. The equipment was regularly calibrated at an accredited metrology laboratory. The pressure gauges were lowered and raised on a deep cable at a speed of no more than 0.5 m/s to

eliminate dynamic errors. Pressure measurements were performed using high-precision electronic deep pressure gauges “PDD-6K” with an accuracy class of 0.05% and “Kvant-M” with an accuracy class of 0.025%. In each monitored well (key wells #1, #4, #8, #14, #15, #20, #21), at least three consecutive measurements were taken at 15-minute intervals to confirm the stability of the readings. Not only static pressure was recorded, but also the temperature at the bottom of the well to bring the data to standard conditions [18]. Statistical processing (exclusion of outliers, averaging), bringing pressures to a single plane (for example, to a mark of –2400 m by absolute mark) and calculation of pressure gradients were performed. Based on the averaged values of formation pressure in the wells for each calendar year, isobar maps were constructed in the Petrel software environment. The kriging algorithm, which provides optimal interpolation by taking spatial data correlation into account, was used. Maps were constructed for the J-XI horizon in a section linked to the structural map. The reservoir pressure dynamics shown in Fig. 3 are key hydrodynamic evidence.

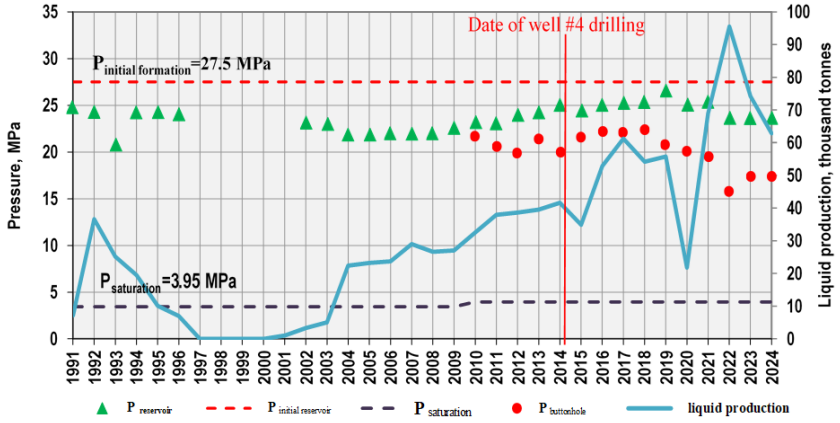


Fig. 3 Dynamics of reservoir pressure at the X field

Alt text: *line graph showing reservoir pressure decreasing until 2022, followed by an unexpected increase and stabilization despite the absence of reservoir pressure maintenance.*

Against the backdrop of intensive fluid extraction and the absence of RPM, an abnormal increase in pressure is evident.

The dynamics of the reservoir pressure ($P_{initial\ formation}$) at Field X are a key indicator of the atypical mechanism of water flooding. The initial reservoir pressure ($P_{initial\ formation}$) was 27.5 MPa, which is typical for an undisturbed deposit. Despite intensive oil production and the absence of RPM system, the reservoir pressure does not exhibit the classic continuous decline pattern.

After falling to 23.9 MPa in 2022, an abnormal increase to 25.5 MPa was observed in 2023, followed by stabilization at 25.4 MPa. Such dynamics would be physically impossible without the active inflow of significant volumes of external fluid into the reservoir. The significant variation in pressure values across the wells (from 15.8 to 25.5 MPa) can be seen in the “box plots”, which clearly show the uneven redistribution of pressure in the formation caused by local water inflow through Well #4.

Analysis of the chemical composition of formation water as a diagnostic method

A hydrogeochemical analysis of water extracted during production was performed using a standardized method in accordance with the requirements of GOST 26449.1-85, “Stationary distillation desalination plants. Methods of chemical analysis of saline water”. Samples were collected after allowing the well to spill for 20 minutes to remove contaminated fluid from the wellbore. The samples were then placed in clean, pre-washed, 1-litre polyethylene bottles and rinsed with the water being analyzed. To analyses the cationic composition, the sample was diluted with nitric acid to a pH of less than 2. Samples for determining anions and total mineralization were analyzed without preservation within 24 hours of collection. Total mineralization was calculated as the sum of all determined ions (TDS), with an additional

check performed by measuring the dry residue after evaporation at 105°C, in accordance with GOST 26449.7-85.

The source of the water ingress was identified by comparing the obtained data with the reference chemical compositions of the productive J-XI horizon (based on long-term monitoring of background Well #20) and the Albian-Cenomanian aquifer (based on sampling of well K_1al). The key diagnostic features were the presence of sulphate ions (SO_4^{2-}), which are practically absent in J-XI waters (< 5 mg/l), but characteristic of the Alb-Cenomanian (800-1,000 mg/l); a decrease in total mineralization, relative to J-XI background values (155-170 g/l); and a change in ion ratios: the metamorphism coefficient rNa/rCl (0.75-0.82 for J-XI, versus 1.2-1.5 for the Alb-Cenomanian); the rCa/rMg coefficient (2.5-3.0 versus 0.8-1.0); and the SO_4^{2-}/Cl^- ratio (0 versus > 0.5). A comprehensive assessment of these parameters confirmed not only the flow from the Alb-Cenomanian horizon, but also quantitatively estimated the degree of water mixing and traced the spatial dynamics of the technogenic watering front.

To confirm the hypothesis of flow and identify other potential sources of water ingress, a detailed analysis of the chemical composition of water extracted during production was conducted (Table 2).

Table 2

Chemical composition of water produced from wells at the X field

Well	Date	Density, g/cm^3	Cl^-, mg/l	SO_4^{2-}, mg/l	HCO_3^-, mg/l	Ca^{2+}, mg/l	Mg^{2+}, mg/l	Na^++K^+, mg/l	Total mineralization, g/l
K_1al	–	1.020	1550.0	925	25	250	250	200	3.2
20	10/01/2023	1.114	106350	–	170,8	10400	3744	49928.4	170.6
20	28/06/2023	1.110	99260	–	122	8400	4512	46138	158.4
20	08/05/2024	1.113	100146.3	–	146,4	9760	3840	46446.2	160.3
20	09/01/2025	1.116	97487.5	–	244	9760	5184	42182	154.9
20	25/06/2025	1.115	102805	–	244	10200	4080	47242	164.6
12	16/05/2025	1.112	96069.5	–	250,1	9000	3960	44484.3	153.8
21	05/10/2023	1.115	96601.2	–	268,4	8640	4656	43916.2	154.1
21	10/09/2025	1.060	58138	470.7	195,2	5700	1620	28359	94.5
1	07/07/2024	1.110	95715.0	–	170,8	8000	4608	44132.4	152.6
1	08/09/2024	1.112	101918.8	–	122	8800	4608	47219	162.7
1	04/11/2024	1.080	74445.0	182.4	170,8	7200	2304	35755.8	120.1
1	25/06/2025	1.102	99260	–	244	10000	3720	45862	159.1
15	19/07/2023	1.102	92170	28.8	170,8	7680	4224	42950.2	147.2
15	10/09/2025	1.020	21270	1201	152,5	1600	480	11672.5	36.4
14	05/05/2023	1.109	98573.8	–	122	8480	4416	46565	158.2
14	12/10/2024	1.114	93942.5	–	170,8	7360	4224	44454.4	150.2
14	10/09/2025	1.092	86852.5	96	244	8000	3600	40388	139.2
8	04/07/2023	1.110	99260	–	146,4	8800	4272	46147.2	158.6

The presence of SO_4^{2-} ions in concentrations of up to 182.4 mg/l in samples from Well #1 (dated 04/11/2024) is the key diagnostic feature confirming flow from the Alb-Cenomanian horizon, while natural waters of the J-XI horizon are characterized by the virtual absence of sulphates. Background values of high total mineralization (154.9-170.6 g/l) were consistently observed in Well #20 during 2023-2025, as was a chloride-sodium composition characteristic of undisturbed waters of the productive J-XI horizon [20].

To assess the spatial distribution of anthropogenic waters and the dynamics of the process in 2025, a comparative analysis of samples collected simultaneously from three wells in the field was performed. The obtained data revealed a clear hydrogeochemical gradient, confirming and detailing the flow mechanism:

Well 21 shows classic signs of mixing, with the appearance of a significant concentration of SO_4^{2-} (470.7 mg/l), accompanied by a sharp decrease in total mineralization (to 94.5 g/l), compared to background values (approximately 160 g/l, as observed in Well 20). This suggests an influx of less mineralized,

sulphate-enriched waters from the Albian-Cenomanian complex into the area, resulting in the intensive dilution of formation waters.

Well 14 is at an intermediate stage of water ingress, with traces of SO_4^{2-} (96 mg/l) recorded and a mineralization level of 139.2 g/l occupying a transitional position between the background level in Well 20 and the level in Well 21. This suggests that anthropogenic waters have reached this zone, but the degree of formation water dilution is lower here.

Well 15 is anomalous, indicating a possible complication of the hydrogeological model. The sample has an extremely high SO_4^{2-} content (1,201 mg/l), which exceeds even the Alb-Cenomanian reference level. Total mineralization is abnormally low (36.4 g/l). This composition differs radically from both the background level in Well 20 and the mixing pattern in Wells 21 and 14, and may therefore indicate the presence of an additional, smaller source of water.

Thus, the decrease in total mineralization in Wells 21 and 14, compared to the stable background value in Well 20, clearly indicates the active dilution of highly mineralized J-XI waters with less mineralized Albian-Cenomanian waters. Not only does the variability in chemical composition indicate the mixing of waters of different origins, it also allows us to map the direction and intensity of anthropogenic flow spreading through the formation from Well #4. The anomaly in Well 15 highlights the need to consider the multicomponent nature of the water supply system.

The flow dynamics can be finally confirmed and all water sources identified in the future using more detailed methods, such as isotope analysis (e.g. stable isotopes of deuterium (δ^2H) and oxygen ($\delta^{18}O$)), which has been successfully employed to solve similar issues, even in the absence of injection wells.

Laboratory core testing

Core samples were tested in the laboratory using standard methods and specialized equipment. Absolute air permeability and open porosity were determined using a UIK-3 device at atmospheric pressure and a temperature of 20°C, in accordance with GOST 26450.2-85. Capillary pressure tests were performed using a Russian-made capillary apparatus and the semi-permeable membrane method at a formation temperature of 65°C and pressures up to 3.5 MPa. Relative phase permeabilities (RPP) were determined using an LXRT-400T filtration unit in a steady state, at a reservoir temperature of 65°C and a pressure of 25 MPa, with model reservoir fluids – degassed oil from Field X and synthetic reservoir water – being used. A petrographic examination of thin sections was performed using a Carl Zeiss Axio Imager A2m polarization microscope at magnifications ranging from 50x to 400x. The thin sections were prepared using a standard method involving grinding core samples and subsequently polishing them to a thickness of 0.03 mm. The following parameters were analyzed during the research: lithological composition; grain size and roundness; cement type and composition; porosity characteristics; the presence and composition of autigenic minerals; rock texture features; and signs of secondary changes. Comprehensive analysis of the obtained data allowed us to establish a direct correlation between the reservoir's petrographic characteristics and its filtration and storage properties. Detailed laboratory studies of the core characterized the FES of the productive formation (Table 3). The results revealed the reservoir to be extremely heterogeneous.

Table 3

Results of laboratory studies of the core

Sample	Depth, m	Porosity, %	Permeability, mD	Lithological characteristics
39	2443.87	18.8	131.8	fine-grained, polymictic sandstone
43	2445.81	21.2	471.0	fine- to medium-grained sandstone
45	2446.92	21.5	794.3	medium-grained sandstone
47	2447.82	22.4	1200.0	medium-grained, well-sorted sandstone

To study heterogeneity in more detail, capillary pressure curves were constructed (Fig. 4), which clearly demonstrate heterogeneity in the pore space.

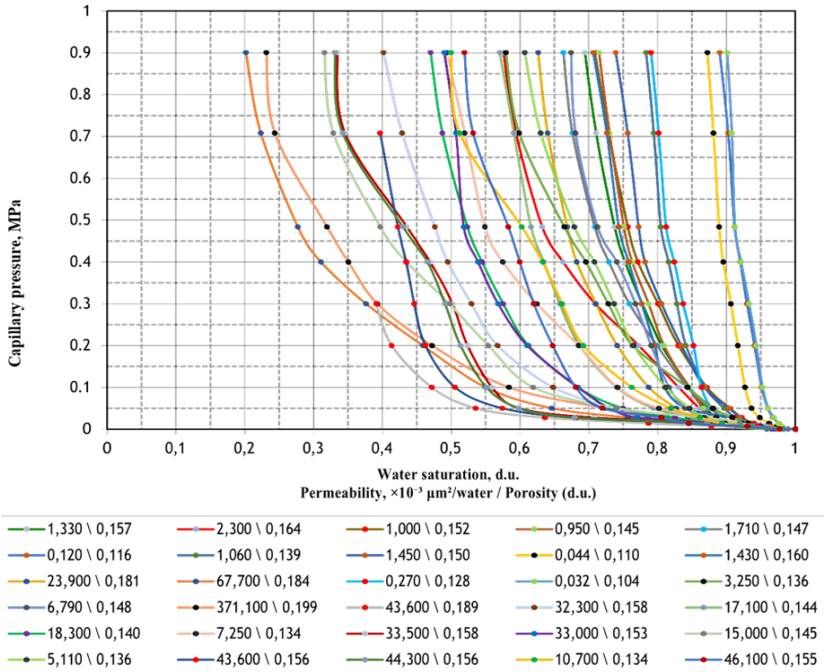


Fig. 4 Capillary pressure curves for core samples of different permeabilities

Alt text: *graph comparing capillary pressure curves of core samples with different permeabilities, illustrating wide variation in pore structure and displacement characteristics.*

Highly permeable samples are characterized by low capillary pressure thresholds (less than 0.1 MPa), whereas low-permeability samples have high thresholds (up to 1.5 MPa).

This is a classic sign of a wide distribution of pore sizes in terrigenous reservoirs [6, 17]. The spread of the curves confirms the complex structure of the pore space, which is typical of terrigenous reservoirs of a similar origin and predetermines the formation of preferential filtration paths [21].

Analysis of the curves reveals fundamental patterns in the reservoir's structure:

High heterogeneity of the pore space. The curves do not form a single cluster, but instead occupy a wide band, visually confirming the reservoir's extreme heterogeneity. There is significant variation in capillary entry pressure (the pressure at which oil begins to be displaced by water), ranging from less than 0.1 MPa to over 0.5 MPa. This directly indicates the diversity of pore channel sizes.

There is a clear correlation with filtration and capacitance properties (FCP). The curves demonstrate a predictable dependence on permeability. Samples with high permeability (e.g. 371.1×10^{-3} µm²) are characterized by a flat curve that is shifted towards the region of low capillary pressure. This indicates the predominance of wide pore channels (micropores) and low resistance to fluid filtration.

There are low permeability differences. By contrast, samples with low permeability (e.g. 0.032 and 0.044×10^{-3} µm²) exhibit steep curves that are shifted towards the region of high capillary pressure. This curve shape indicates the predominance of thin pores and capillaries (micropores), which are difficult to displace.

Impact on the waterflooding process. The obtained data are key to interpreting the mechanism of abnormal waterflooding. The identified heterogeneity leads to uneven oil displacement by water (the phenomenon of “channeling”) [22]. In the case of man-made flow, highly mineralized water primarily breaks through highly permeable interlayers with low capillary pressure, forming “water-flooded channels”. At the same time, significant volumes of oil in low-permeability zones may remain undisplaced, sharply reducing the ultimate oil recovery and explaining the high water cut of production with significant residual reserves.

Thus, the analysis of capillary curves confirmed the high lithological heterogeneity of the reservoir, as previously established, and quantitatively characterized its nature, explaining the speed and manner of the spread of man-made flow in the formation.

Microscopic examination of thin sections

Petrographic studies of thin sections (Fig. 5) confirmed the reservoir's lithological diversity.

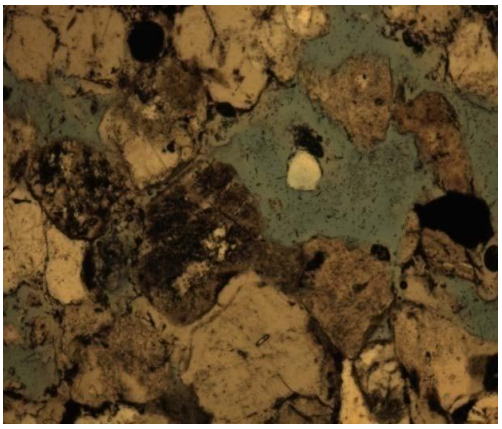


Fig. 5 Petrographic thin sections of core samples from borehole #4 at a depth of 2445-2447 m

Alt text: *two microscopic images of sandstone thin sections showing differences in grain size, cementation, and pore structure between low- and high-permeability samples.*

A-Medium-grained, well-sorted sandstone (sample 47, permeability 1200 mD). Visible rounded grains of quartz (*Qtz*) and feldspar (*Fsp*) with pore clay cement (*Cl*). B: Fine-grained sandstone with compacted clay-carbonate cement (sample 39, permeability 131.8 mD). The presence of autigenic pyrite (*Pa*) indicates a reducing diagenetic environment. These images directly correlate with FES data, visualizing the cause of the reservoir's high heterogeneity.

DISCUSSION

Based on the results obtained, the following diagnostic criteria can be proposed for identifying atypical technogenic water injection mechanisms in oil fields:

- abnormal stabilization or increase in reservoir pressure under conditions of intensive production and absence of an RPM system;
- localized point-source water influx associated with casing or cement sheath integrity failure;
- hydrogeochemical mismatch between produced water and native formation water, including the appearance of marker ions (e.g., SO_4^{2-});
- rapid, non-frontal growth of water cut accompanied by strong spatial pressure heterogeneity;
- indirect evidence of sustained casing pressure or behind-casing flow from geophysical well logging.

The simultaneous occurrence of these features reliably indicates anthropogenic crossflow-driven water injection rather than classical geological waterflooding mechanisms.

Implications for Production System Management and Decision-Support:

The identification of this atypical mechanism is not merely a geological or technical exercise; it provides critical input for production management systems. The proposed diagnostic criteria should be formalized into a surveillance protocol within an integrated asset management framework.

1. Risk Management Integration: The primary risk – loss of well integrity leading to reservoir contamination, must be elevated in the field's risk register. Continuous monitoring of annulus pressure (SCP) and produced water chemistry becomes a key performance indicator (KPI) for well integrity health, moving from a reactive to a proactive control measure.
2. Decision support for Interventions: The methodology establishes a direct correlation between diagnostic data (e.g. the appearance of SO_4^{2-}, localized pressure increases) and intervention decisions. This enables a tiered response, ranging from investigating a single well's annulus to planning a field-wide isolation campaign. This optimizes workover budgets and priorities.
3. System Performance Optimization: Understanding this mechanism enables the field's hydrodynamic model to be recalibrated. Managers can simulate the impact of shutting in or repairing the faulty well

on overall reservoir pressure distribution and sweep efficiency. This supports the adaptation of long-term strategies beyond short-term production targets.

4. Lifecycle Management: This case highlights the importance of improving well integrity management throughout the asset's lifecycle, particularly in late-stage fields. Integrating geophysical logs, hydrochemical data and pressure monitoring into a digital twin of the asset can provide early warnings and effectively make well integrity a managed subsystem of the broader production system.

Therefore, it is essential to integrate these diagnostic and management principles in order to mitigate the specific crossflow mechanism identified in this study.

A comprehensive data analysis identified the dominant mechanism of water ingress as the crossflow of highly mineralized water from the Albian-Cenomanian aquifer into the productive J-XI formation through a defect in the production casing of Well #4. This process operates according to the principle of "uncontrolled reservoir pressure maintenance (RPM)", whereby an external aquifer with higher formation pressure actively injects water into the producing reservoir.

The obtained results are consistent with findings reported by other researchers, who note that, at the late stage of field development, anthropogenic factors increasingly dominate over geological ones in controlling water ingress processes [7, 9]. The high reservoir heterogeneity identified in this study is not anomalous but is typical of terrigenous reservoirs [6, 15]; however, it significantly amplifies the consequences of crossflows by promoting the formation of highly permeable preferential channels for extraneous water breakthrough.

Thus, the diagnosis and mitigation of atypical water injection mechanisms should be implemented within a **full-scale, integrated production management system** that combines well integrity control, reservoir pressure surveillance, hydrogeochemical monitoring, and system-level decision-making, since failures of individual wells under late-stage development conditions directly translate into field-wide hydrodynamic imbalance, accelerated water cut growth, and loss of production efficiency.

The comprehensive diagnostic methodology developed in this study, integrating hydrodynamic, hydrogeochemical, and geophysical approaches, has demonstrated high efficiency and can be recommended for application in other oil fields affected by abnormal water ingress.

CONCLUSION

This study bridges the gap between subsurface technical analysis and production systems engineering. Its scientific and practical novelty lies not only in identifying a distinct class of water injection mechanisms but also in developing a diagnostic framework that serves as a critical module for integrated production management.

The study's scientific novelty lies in identifying and substantiating a distinct class of atypical technogenic water injection mechanisms operating under late-stage field development conditions. It has been demonstrated that man-made loss of well integrity can result in an "uncontrolled RPM" effect, even in the absence of a reservoir pressure maintenance system, leading to active water injection from overpressured aquifers into productive formations.

The study establishes that an abnormal increase or stabilization of reservoir pressure during depletion constitutes a reliable early diagnostic indicator of technogenic crossflows. Integrating geophysical well logging, reservoir pressure monitoring, hydrogeochemical markers and petrophysical core analysis provides a robust methodological framework for distinguishing this mechanism from classical waterflooding scenarios.

The proposed diagnostic approach and conceptual model can be transferred to other mature oil fields with high water cut, particularly where traditional geological explanations cannot account for observed hydrodynamic anomalies. These results expand our current understanding of water ingress mechanisms and highlight the importance of managing well integrity to maintain reservoir performance and production efficiency in the late stages of development.

Based on the results obtained, a set of practical recommendations has been developed. The first priority is to carry out repair and isolation work on Well #4 in order to eliminate the crossflow channel from the Albian-Cenomanian aquifer and restore the integrity of the production casing. In the medium term, a regular monitoring program for casing and cement sheath integrity in all production wells in the field should be implemented using modern diagnostic technologies. Strategically, it is necessary to adapt the field development system to account for the identified anthropogenic water breakthrough mechanism, including the potential redistribution of production loads among wells and the adjustment of operating regimes to minimize the further propagation of man-induced water intrusion.

Future research prospects include developing hydrodynamic and geomechanically models of the anthropogenic crossflow to assess its quantitative impact on the ultimate oil recovery factor, and formulating preventive technical and organizational measures for the early detection and mitigation of similar scenarios in analogous fields. The results obtained can be used to revise well integrity monitoring systems and optimize field development strategies in the late stages of reservoir exploitation.

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