

Article

The Problem of Equipment Erosion in Western Siberian Oilfields

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Abstract

This study addresses the operational challenges of developing hard-to-recover reserves such as heavy-oil rims in weakly consolidated sandstone reservoirs of Western Siberia, which account for a significant share of Russia's resource base. The core challenge is the inevitable solid production during extraction, leading to abrasive wear, erosion, plugging of downhole pumping equipment, frequent failures, and substantial economic losses. The objective of this work is a comprehensive analysis of the causes of sand production and related equipment failures by integrating published research with field failure data. The research methodology includes an analysis of scientific publications and a statistical review of the causes and frequency of Electrical Submersible Pump (ESP) failures in wells produced by the PK formation. The results show that the primary failure causes are erosive wear (predominantly in medium-rate deviated wells) and plugging by produced solids (predominantly in low-rate horizontal wells), which correlate with sand transport regimes and the particle size distribution (PSD) of produced solids. The failure frequency was found to be comparable across different well types, but the equipment damage mechanisms differed significantly. The discussion confirms the necessity for an integrated approach to modeling the "reservoir–sand control screen–wellbore" system to optimize operating parameters and select effective sand control techniques.

Keywords: oil rims; sand production; produced solids; equipment failures; erosive wear; weakly consolidated reservoirs

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1. Introduction

The development of heavy-oil rims at gas-condensate fields in Western Siberia is a strategic priority for the Russian oil and gas industry amid the depletion of conventional reserves [1,2]. Total oil reserves in such fields as East Messoyakhskoye, West Messoyakhskoye, Russkoye, Tazovskoye, and Van-Yeganskoye are estimated in billions of tons [3,4]. However, production is challenged by a combination of factors: the presence of a gas cap and active bottom water, low rock strength in weakly cemented reservoirs, and high oil viscosity. These lead to rapid water breakthrough, gas breakthrough, and near-wellbore zone destabilization [5–7].

Development efficiency and associated technological challenges, such as sand production, are directly influenced by the geological and physical properties of the productive reservoirs [8–10]. This study focuses on the Pokur Formation group, which belongs to the lower Pokur subformation (Aptian-Albian stage) of Western Siberia.

Lithologically, the deposits comprise a complex interbedding of sandstones, siltstones, and argillites. The reservoir rocks are sandstones, predominantly fine-, medium-, and coarse-grained, characterized by weak to moderate cementation with carbonate-clay material [11–13]. The low shear strength of this weakly cemented carbonate-clay cement is the key factor enabling the mobilization of rock particles due to changes in stress within the near-wellbore zone during production [14,15].

A characteristic feature of the PK formation group is its complex structure and vertical saturation zoning. The lower layers (PK_{19–20}, PK₁₈) often contain oil and oil–gas–condensate accumulations, while the upper ones (PK₁₇, PK₁₆, PK₁₅) are primarily gas- and gas–condensate-bearing [16,17]. This diversity, including the presence of an active gas cap and aquifer, necessitates varied production strategies [18], which in turn affect the mechanisms of rock failure and sand production differently.

An important factor influencing abrasive wear and the transport properties of produced solids is particle shape. For the terrigenous reservoirs of the Pokur Formation, which include the PK layers, particles are typically subrounded to rounded due to their transport and abrasion in a shallow marine depositional environment. Compared to angular particles, rounded ones exhibit different abrasive behavior and possess better transport characteristics in fluid flow. This must be considered in the hydrodynamic modeling of the “reservoir–wellbore” system and in the selection of sand control methods [19–21]. The consequence of developing such reservoirs is sand production in the wells [22–24]. This leads to abrasive wear and erosion of downhole and surface equipment, the formation of sand plugs, wellbore sand accumulation, and, consequently, numerous well failures and downtime. An analysis of ESP failures in the PK formation group confirms the severity of this problem; over a 42-month period, 536 downhole pump failures were recorded across 315 wells.

The objective of this work is a practical analysis of equipment failure statistics to formulate optimal well operation strategies for hard-to-recover reserves in Western Siberia. Specifically, this study aims to (1) analyze the factors causing sand production, (2) classify downhole pump failures based on field statistics, and (3) establish a correlation between well operating conditions, sand transport mechanisms, and types of equipment damage.

2. Materials and Methods

The study was conducted using a combination of theoretical and practical methods. The theoretical part involved a review of the literature on the development of heavy-oil rims, rock mechanics, and sand production hydrodynamics [25–27].

The practical part of the work was based on the analysis of field data from a well stock produced by the weakly consolidated PK formation. The dataset included 461 wells (Figure 1), of which 411 were producers. Data covering a 42-month period (from the beginning of 2018 to the second quarter of 2021) were analyzed. Failure analysis (Figure 2) was performed using a statistical method involving the calculation of failure incidence rate ($p = m/n$, where m is the number of failures and n is the number of wells of a given type) and the classification of shutdown causes into the following categories: R-0 (cable insulation failure), seizure, pump starvation, scheduled preventive maintenance, and performance decline (P/D). Failures attributed to complicating factors, specifically erosive wear and produced solids, were analyzed separately.

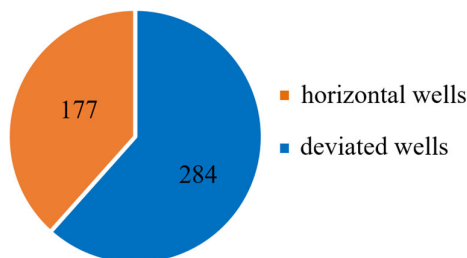


Figure 1. Distribution of wells penetrating the Pokur Formation by type.

For wells with an operating time exceeding 365 days, an analysis of failure causes after the expiration of the warranty period was conducted. The PSD of the produced solids was determined by sampling material from failed ESP units.

As shown in Figure 1, the analysis was performed on a representative well fleet comprising horizontal wells and deviated wells in a 40:60 ratio. The failure distribution presented in Figure 2 clearly illustrates the scale of the problem. A significant portion of the well fleet, particularly horizontal wells, experienced ESP failures during the observation period. This underscores the necessity of conducting a detailed root-cause analysis of the failure mechanisms.

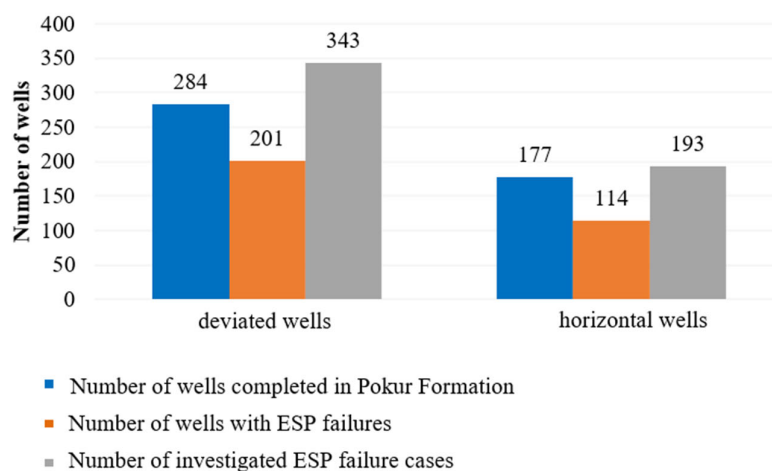


Figure 2. Active well inventory with ESP failures.

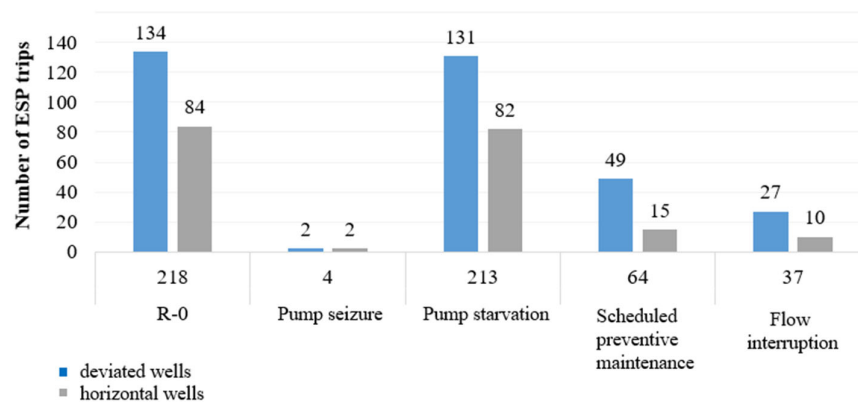
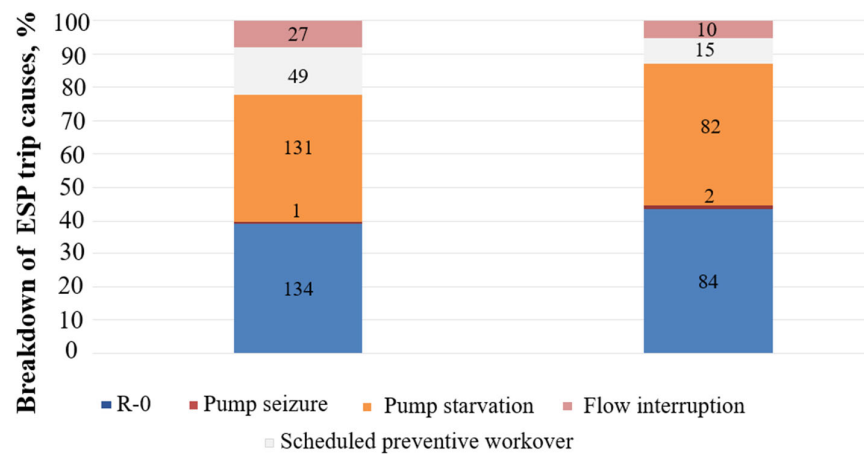
3. Results

3.1. Analysis of Submersible Pump Failures

Statistical analysis revealed 536 ESP failures across 315 wells during the study period. The failure rate was 1.20 for deviated wells and 1.09 for horizontal wells, indicating comparable problem severity across both completion types. According to Table 1 and Figures 3 and 4, the primary causes of ESP shutdowns were cable insulation failure (R-0) and pump starvation.

Table 1. Number of ESP shutdown incidents in deviated and horizontal wells.

Cause of ESP Shutdown	Number of ESP Trips				
	Number of ESP Failure Cases	Deviated Wells (DW)		Horizontal Wells (HW)	
		Number of Cases	% of All DW Failures	Number of Cases	% of All HW Failures
Cable insulation failure (R-0)	218	134	39	84	44
Pump seizure	4	2	1	2	1
Pump starvation	213	131	38	82	42
Scheduled preventive maintenance	64	49	14	15	8
Performance decline	37	27	8	10	5

**Figure 3.** Number and causes of ESP trips.**Figure 4.** Breakdown of ESP failure causes.

Statistical data from Table 1 and Figures 3 and 4 indicate that cable insulation failure (R-0) and pump starvation statistically dominate the failure statistics. However, subsequent root-cause analysis suggests that these events often represent secondary manifestations rather than primary failure mechanisms. Instead, they are frequently triggered by aggravating factors, specifically erosive wear and plugging by produced solids, which initiate cascading equipment failures [22,28].

A more detailed failure mode analysis reveals that the underlying root causes of many ESP trips are indeed these aggravating factors. As illustrated in Figures 5 and 6, the most prevalent contributors to equipment failure are produced solids and erosive wear.

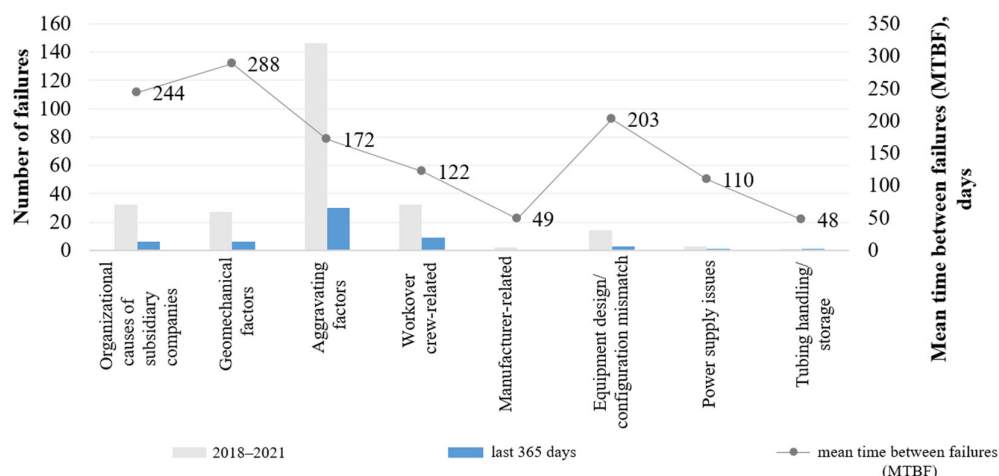


Figure 5. Failure count and mean time between failures (MTBF).

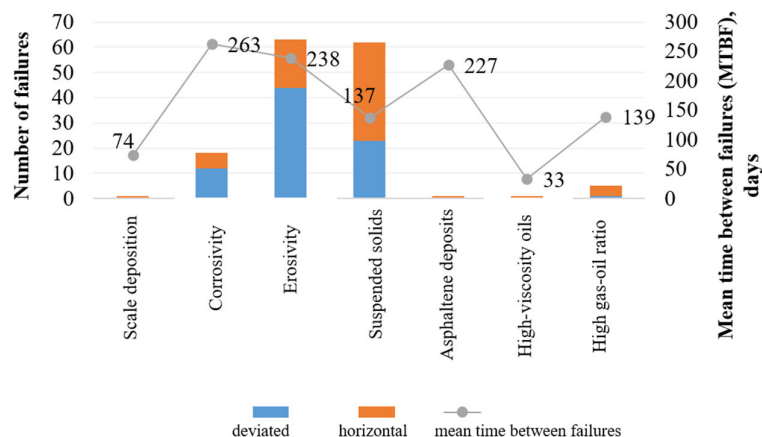


Figure 6. Failure count attributable to aggravating factors.

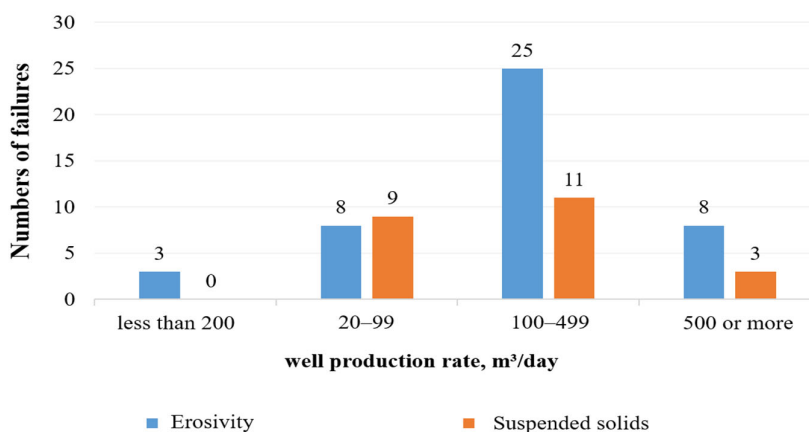
The low mean time between failures (MTBF < 250 days) for these wells underscores the urgent need for preventive measures targeting sand production and its downstream consequences.

According to Figure 6, erosive wear and produced solids are the dominant aggravating factors driving failures. Their combined contribution significantly exceeds that of other factors such as scale deposition or corrosion, highlighting sand transport as the primary operational challenge.

A total of 125 failure cases linked to produced solids and erosive wear were recorded across 105 wells. The breakdown by well type and failure cause is presented in Tables 2 and 3, as well as Figure 7 [29,30].

Table 2. Wells in which equipment failures occurred due to sand production.

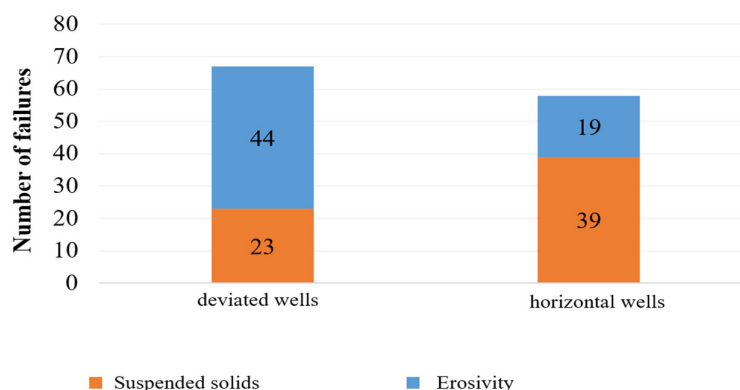
Causes	Number of Wells with ESP Failures			
	Total Number of Wells	DW	Share of DW, %	HW
Erosive wear	51	35	68.6	16
Plugging by produced solids	54	23	42.6	31
Erosion + plugging by produced solids	105	58	55.2	47

**Figure 7.** Number of failures in deviated wells as a function of production rate.

Analysis of Tables 2 and 3 and Figure 8 reveals a distinct separation of dominant damage mechanisms depending on well trajectory. In deviated wells, failures are predominantly driven by erosive wear (69.8% of cases), whereas in horizontal wells the primary issue is plugging caused by solid accumulation (62.9% of cases). This dichotomy stems from differences in flow hydraulics and particle transport conditions inherent to wellbores of different geometries [31–33].

Table 3. Number of ESP failure cases by cause in wells with equipment failures.

Causes	Number of ESP Failure Cases			
	Total Number of Wells	DW	Share of DW, %	HW
Erosive wear	63	44	69.8	19
Plugging by produced solids	62	23	37.1	39
Erosion + plugging by produced solids	125	67	53.6	58

**Figure 8.** Equipment failure caused by suspended solids and erosive wear.

The analysis further identified a clear dependency of failure mode on well production rate and trajectory (Figures 7 and 9). In deviated wells, erosive wear dominates at medium-to-high production rates (>100 m³/day), where elevated flow velocities induce the abrasive erosion of pump components [34–36]. In horizontal wells, the principal failure mechanism shifts to solid deposition at low production rates (<100 m³/day), where insufficient flow velocity fails to maintain effective particle transport through the pump, leading to accumulation and blockage [37,38].

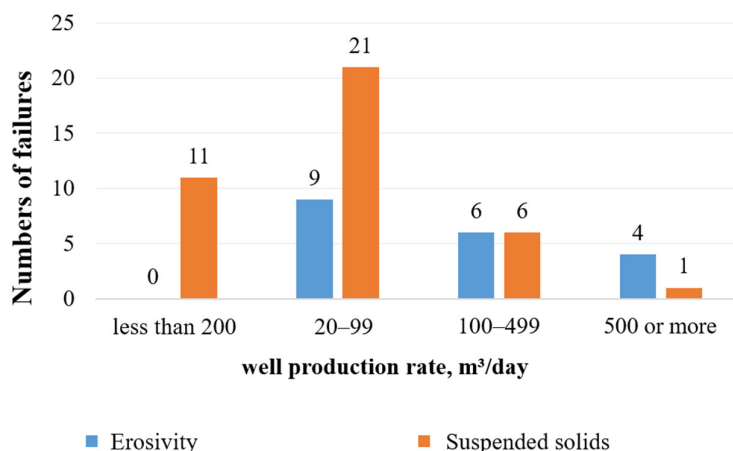


Figure 9. Number of failures in horizontal wells as a function of production rate.

3.2. Particle Size Distribution and Solids Transport

A particle size distribution analysis of field samples (Figure 10) confirmed that fewer coarse particles (>250 μ m) reach the pump intake in horizontal wells due to gravitational settling within the horizontal section. In deviated wells, coarse particles are efficiently entrained toward the pump intake, inducing severe erosive wear of hydraulic components, whereas fine particles are predominantly transported to surface facilities.

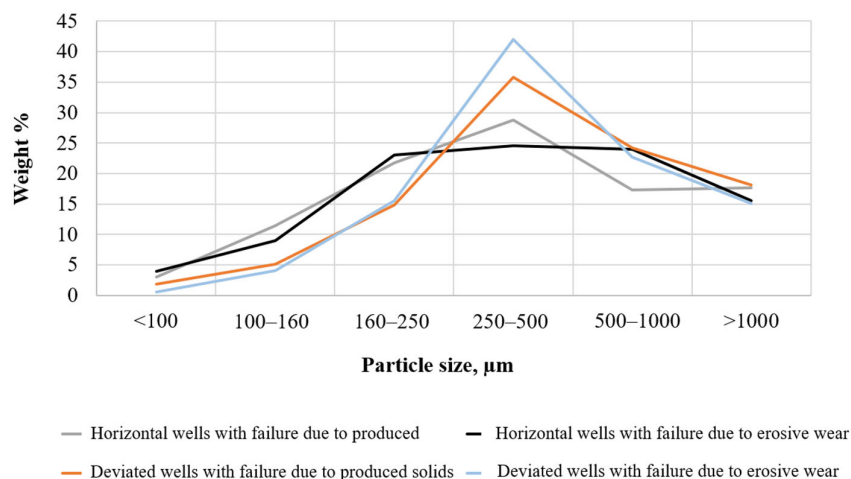


Figure 10. Particle size distribution of produced solids in horizontal and deviated wells.

3.3. Wells with Extended Operating Time

An analysis of wells with operating time exceeding 365 days (Figure 11) showed that only 12 out of 72 wells failed due to equipment wear-out, highlighting the dominant role of external factors (sand production) in premature failure.

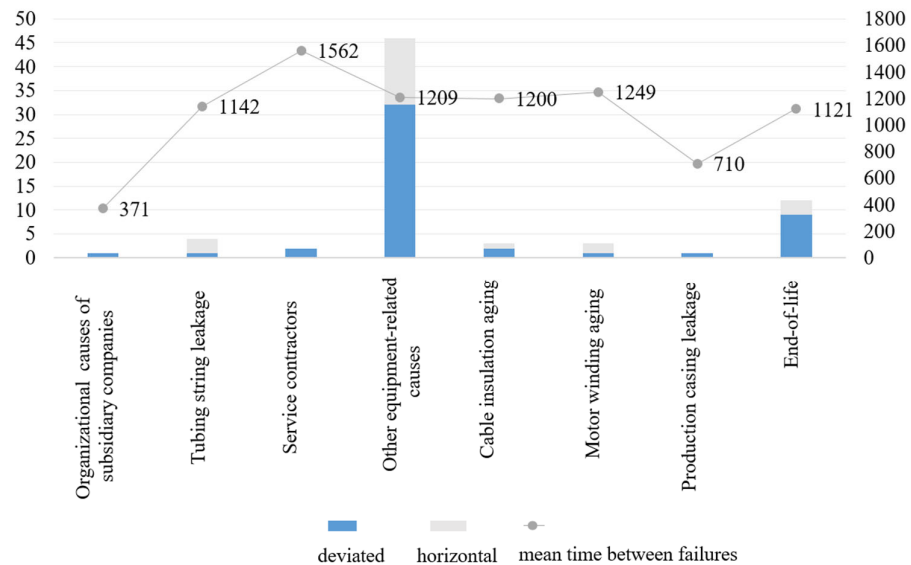


Figure 11. Failure causes and mean time between failures for wells with operating time exceeding 365 days.

Data from Figure 11 demonstrate that the primary cause of low operating time is not natural equipment wear but external factors, predominantly sand production.

4. Discussion

The low rock strength of weakly consolidated reservoirs in the Pokur Formation and heavy-oil rims of Western Siberia inevitably results in the production of solid matter during well operation. However, the operational consequences vary significantly depending on production rates and well trajectories. Our findings demonstrate a direct link between the geomechanical state of the near-wellbore zone, multiphase flow hydrodynamics, and specific downhole equipment failure modes.

These results align with established principles of solid particle transport in multiphase flows [39]. In high-rate deviated wells, flow velocities are sufficient to maintain particles in heterogeneous or homogeneous transport regimes (Figure 12). This prevents bottomhole accumulation but simultaneously induces severe erosive wear of downhole equipment. Conversely, in medium-rate horizontal wells, flow velocities frequently fall below the critical threshold, particularly in the horizontal section, where gravitational forces promote particle settling according to flow regimes 1 and 2. This leads to sand plug formation and pump blockage, typically requiring workover interventions.

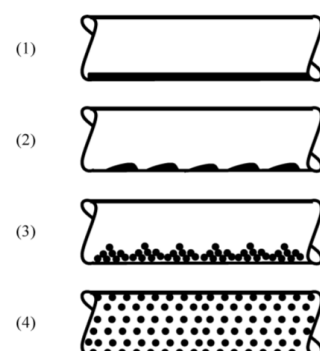


Figure 12. Flow regimes of sand-laden fluid: (1) Stationary sand (dunes); (2) moving sand (dunes); (3) heterogeneous flow; (4) homogeneous flow [40].

The transport regimes illustrated in Figure 12 directly correspond to the observed failure mechanisms: erosive wear in deviated wells occurs under regimes 3 and 4, while plugging by produced solids in horizontal wells matches regimes 1 and 2. This underscores the necessity of calculating critical flow velocities on a well-specific basis [41].

To ensure efficient particle transport without settling, optimal production strategies must be tailored to each well type using integrated geomechanical and hydrodynamic modeling. This approach enables the determination of the maximum allowable drawdown and safe bottomhole pressure decline rates to minimize near-wellbore zone damage, alongside the minimum required flow velocity for effective sand transport [42–44].

Gas lift technology can be applied to minimize particle settling in the horizontal section by increasing flow velocity [45,46]. Additionally, installing downhole chokes ensures stable flow maintenance along the entire horizontal wellbore.

5. Conclusions

Two dominant equipment failure mechanisms dependent on production rate and well trajectory have been identified: erosive wear in high-rate deviated wells and plugging by produced solids in medium-rate horizontal wells.

In deviated wells, erosive wear driven by high flow velocities represents the predominant failure mechanism. These velocities effectively transport particles of all sizes, including coarse fractions ($>250\ \mu\text{m}$), preventing bottomhole accumulation but simultaneously inducing severe abrasive degradation of pump components. For high-rate deviated wells, strict production rate control with an established upper limit is required to minimize erosive damage.

In horizontal wells, the predominant failure mechanism is plugging by solids produced by insufficient flow velocity in the horizontal section. Coarse particles settle under gravitational forces, forming sand plugs. Although particle size distribution analysis indicates a reduced proportion of coarse fractions reaching the pump intake due to in-wellbore settling, this very accumulation of solids constitutes the primary operational challenge.

For medium-rate horizontal wells, critical production rate control with a defined lower limit is essential to maintain the minimum flow velocity required for effective particle transport without settling; operation below this threshold is strictly avoided.

The successful development of hard-to-recover reserves in Western Siberia requires transitioning from universal operational strategies to a well-specific approach. This necessitates the calculation of an optimal drawdown operating window for each well based on integrated modeling that combines geomechanical and hydrodynamic analyses.

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Conflicts of Interest: Authors Ilya Stecyuk and Nikolai Dzirun were employed by LLC “RN-Purneftegaz”. The employer had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript; or in the decision to publish the results. The remaining authors declare no conflict of interest.

Abbreviations

The following abbreviations are used in this manuscript:

ESP	Electrical Submersible Pump
MTBF	Mean time between failures
PSD	Particle size distribution

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