

Article

Inhibitory Technology for Preventing the Formation of Asphaltene–Resin–Paraffin and Gas Hydrate Deposits in Oil Wells

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Abstract

The formation of asphalt–resin–paraffin deposits (ARPDs) and gas hydrate deposits (GHDs) in oil wells equipped with electric submersible pumps (ESPs) remains a significant challenge in the oil and gas industry. This study aims to develop an inhibitory technology to prevent these deposits by utilizing the synergistic effect of chemical reagents combined with the optimization of ESP operating parameters. Based on previously published mathematical modeling and laboratory studies by the authors, this work presents the technological implementation of the inhibition system and its economic assessment. Specifically, optimal reagent dosages were calculated considering their synergistic interactions, a periodic injection regime was established, and the impact on the well's mean time between failures (MTBF) was evaluated. Results demonstrate that optimizing ESP parameters shifts the onset depth of GHD formation by 119.4 m (25%) and ARPD formation by 72.6 m (6%). The application of the selected ARPD inhibitor at 0.055 wt.% reduced the thermodynamic hydrate inhibitor (methanol) dosage by 12.17% and enabled a transition from continuous to periodic methanol injection. Consequently, the predicted MTBF increased from 277 to 419 days (+50%). An eight-year economic analysis showed a positive net present value with a payback period of 14 months. Thus, the proposed technology is recommended for field testing in high-paraffin, low-resin oil fields operating under permafrost conditions.

Keywords: gas hydrates; asphalt–resin–paraffin deposits; inhibitory technology; electric submersible pump; flow assurance; hydrate inhibition; wax inhibition; production optimization; synergistic effect



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1. Introduction

The simultaneous formation of ARPDs and GHDs in oil wells remains one of the major flow assurance challenges in oil production, particularly in fields located in permafrost regions [1–3]. These deposits reduce production efficiency by lowering well productivity, increasing workover frequency, and raising operating costs [4–6]. The simultaneous formation of ARPDs and gas hydrates poses a particular challenge in wells equipped with ESPs [7,8]. Under favorable thermobaric and physicochemical conditions, both types of deposits can form concurrently [9,10], a phenomenon typically observed in wells with high heavy hydrocarbon content in crude oil [11,12], high gas–oil ratios [13], and low temperatures of the produced fluid [14,15].

Traditional mitigation strategies typically involve the separate selection of ARPD and gas hydrate inhibitors without accounting for their co-occurrence [16,17]. However, experimental studies have demonstrated that these processes are interrelated: the presence of paraffinic hydrocarbons can slow down the nucleation of gas hydrates, acting as a natural kinetic inhibitor [9,18]. Furthermore, certain chemical reagents based on surfactants, which are used to prevent ARPDs, also exhibit an inhibitory effect on hydrate formation because they contain low-molecular-weight alcohols and surfactants [19,20].

Our previous studies established the fundamental mechanisms governing the simultaneous formation of ARPDs and gas hydrates [7,9]. In the first study [9], the influence of paraffinic hydrocarbons on the kinetics of hydrate formation in an oil–gas–water system was experimentally established. The results showed that an increase in paraffin content extends the nucleation time of gas hydrates, confirming the role of paraffin as a natural kinetic inhibitor of GHDs.

In the second study [7], a comparative analysis of surfactant-based chemical reagents for the comprehensive prevention of ARPD and gas hydrate formation in oil wells was conducted. Laboratory experiments employing the cold finger method and a high-pressure hydrate autoclave identified the most effective inhibitor formulation. The formulation consisted of a block copolymer of ethylene and propylene oxides based on ethylenediamine (45 wt.%) and methanol (55 wt.%). At an aqueous-phase concentration of 0.055 wt.%, the formulation reduces the equilibrium hydrate formation temperature by 0.55 °C and increases the nucleation time by 7.5%. It was established that this reagent exhibits properties of both thermodynamic and kinetic hydrate inhibitors due to the presence of methanol and the ethylene–propylene block copolymer [21–23].

Despite these advances, translating laboratory findings into field-scale technology remains insufficiently explored [24,25]. In particular, there is a lack of engineering guidelines addressing:

- The optimal selection of ESP operating parameters considering the simultaneous formation of these deposits;
- The calculation of inhibitor dosages during their combined application, accounting for synergistic effects [26];
- The justification for transitioning from continuous to periodic injection of the thermodynamic inhibitor (methanol) in the presence of a kinetic inhibitor in the system;
- The economic evaluation of implementing a comprehensive inhibitory technology.

The aim of this study is to develop an integrated inhibitory technology for preventing the simultaneous formation of ARPDs and GHDs in ESP-operated oil wells, building upon previous laboratory studies and optimizing downhole equipment operational parameters.

The study addressed the following objectives:

1. Optimization of ESP operating parameters to minimize the onset depths of ARPD and GHD formation.
2. Calculation of inhibitor dosages (methanol + selected ARPD inhibitor formulation) accounting for their synergistic effect.
3. Justification of a periodic methanol injection regime based on the kinetic effects of paraffin particles and the selected inhibitor on hydrate formation.
4. Assessment of the impact of the developed measures on MTBF of the well.
5. Calculation of the economic efficiency of implementing the proposed technology.

Although the case study focuses on oil wells in permafrost regions, the integrated optimization framework proposed herein—combining thermobaric modeling, kinetic inhibition principles, and techno-economic evaluation—is transferable to other engineering systems where multiphase flow, deposition phenomena, and equipment reliability intersect.

Examples include geothermal wells [3], CO₂ transport pipelines, and deep-water subsea production systems [21,23].

The scientific novelty of this research lies in the development of a comprehensive inhibition technology for ARPDs and GHDs based on the synergistic effect of jointly applying methanol and a surfactant-based ARPD inhibitor [27]. The proposed technology enables a transition from continuous to periodic methanol injection by exploiting the extended hydrate nucleation time. The study also quantifies the effect of ESP operating parameters on well MTBF under combined ARPD and GHD formation conditions. The practical significance of the developed solutions is confirmed by a positive economic effect, achieved through reduced methanol dosages and an extended operational run life of the oil well. By bridging petroleum engineering, chemical process optimization, and applied economics, this study contributes to the broader scientific discourse on sustainable flow assurance strategies under extreme environmental conditions [22].

2. Materials and Methods

2.1. Object of Study

The study was conducted using data from an ESP-operated oil well at an oil and gas condensate field (OGCF) located in a permafrost region on the Yamal Peninsula. The region is characterized by low ambient temperatures [28], widespread permafrost, and severe climatic conditions, which significantly increase the risk of ARPD and GHD formation in production wells [29].

From a geological perspective, these challenges are primarily associated with the following productive formations of the OGCF:

- BY and NP formation groups (Lower Cretaceous deposits of the Akh Formation, K_{1b}–K_{1v}):
 - Gas–oil ratio: 50–100 m³/m³;
 - Paraffinic crude oil: 3–6 wt.%.
- Yu formation group (Middle Jurassic deposits of the Tyumen Formation, J_{2tm}):
 - Gas–oil ratio: 90–150 m³/m³;
 - High-paraffin crude oil: 6–8 wt.%.

This study focuses on the Yu_{2–6} production zone, which accounts for over 40% of the current recoverable reserves of the field under consideration. Crude oil from this zone is classified as high-paraffin (paraffin content (P) = 7 wt.%) and low-resin (asphaltenes + resins (A + R) = 3 wt.%). The ARPD type is classified as paraffinic (P1).

Key well and reservoir parameters:

- True vertical well depth: 2059 m;
- Internal diameter of production casing: 157.2 mm;
- Internal diameter of tubing: 62 mm;
- Initial pump setting depth: 1562 m;
- Reservoir pressure: 20.5 MPa;
- Bubble point pressure: 16.9 MPa;
- Wellhead pressure: 2.2 MPa;
- Reservoir temperature: 61 °C;
- Produced water cut: 9.1%;
- Gas–oil ratio: 91.74 m³/m³;
- Well productivity index: 9 m³/(day·MPa).

Characteristics of produced crude oil:

- Density of degassed oil: 883 kg/m³;

- Dynamic viscosity of oil: 8.2 mPa·s.

The initial downhole equipment consisted of an ESP-200-1350 unit (with an optimal flow rate of 200 m³/day and a generated head of 1350 m), operating under intensified production conditions with a flow rate of 110.4 m³/day and a bottomhole pressure of 3.56 MPa. During well operation, complications related to the simultaneous formation of ARPDs and GHDs were observed at depths shallower than 194.7 m to the wellhead (for GHDs) and shallower than 1229.7 m (for ARPDs).

The developed inhibitory technology can be applied to analogous fields with similar reservoir fluid characteristics and thermobaric operating conditions. Table 1 presents a list of analogous reservoirs categorized by reservoir fluid composition, for which the proposed technology demonstrates effective performance.

Table 1. List of analogous reservoirs by reservoir fluid composition (compiled by the authors).

Region	Field	Paraffin Content (P) and Asphaltene + Resin Content (A + R)	Gas–Oil Ratio, m ³ /t	Geothermal Gradient, °C/100 m
Krasnoyarsk Krai	Suzunskoye OGCF	P = 6.7 wt.%; (A + R) = 2.5 wt.%	75 (50–100)	2.9 (2.4–3.7)
	Vostochno-Urengoyevskoye OGCF	P = 6.7 wt.%; (A + R) = 2.8 wt.%	180 *	3.1 *
Yamalo-Nenets Autonomous Okrug (YNAO)	Severo-Esetinskoye OGCF	P = 9.3 wt.%; (A + R) = 2.4 wt.%	160 *	3.0 *
	Yarudeyskoye OGCF	P = 11.6 wt.%; (A + R) = 0 wt.%	140 *	3.0 *
	Ust-Chaselskoye OGCF	P = 11.7 wt.%; (A + R) = 0 wt.%	375 (350–400)	3.1 *
	Beregovoye OGCF	P = 9.1 wt.%; (A + R) = 1.3 wt.%	220 *	3.2 *
	Geofizicheskoye OGCF	P = 8.4 wt.%; (A + R) = 2.8 wt.%	190 *	3.1 *

Values marked with an asterisk (*) were estimated using the geological analogy method based on neighboring oil and gas condensate fields with similar stratigraphic position, reservoir depths, reservoir properties, and thermobaric conditions. These values were used solely for comparative analysis due to the absence of published field-specific data.

2.2. Methodology for Optimizing ESP Operating Parameters

The operating parameters of the downhole equipment were optimized to minimize the onset depths of ARPD and GHD formation while maintaining the target production rate. The initial well configuration featured an ESP-200-1350 unit operating under an intensified production regime with a low bottomhole pressure. These conditions promoted intensive oil degassing and reduced the flowing fluid temperature [30], thereby creating favorable conditions for deposit formation.

The optimization procedure consisted of the following steps:

1. **Pump size selection.** Based on the analysis of inflow performance curves and field development system requirements, a transition to a lower-capacity pump—ESP-125-1050 (from the same equipment line)—was justified. The target operating parameters were a flow rate of approximately 90 m³/day and a bottomhole pressure of around 8.8 MPa.
2. **Variation in operating parameters.** For the selected pump, pressure and temperature distributions along the wellbore were modeled while varying the following parameters:
 - Pump setting depth (varied up to a maximum of 1800 m);
 - Electrical submersible motor (ESM) operating frequency (varied in the range of 40–60 Hz);
 - Wellhead choke diameter (feasibility of installation was evaluated).
3. **Evaluation of deposit formation risk.** For each operating scenario, the onset depths of ARPD and GHD formation were predicted using the mathematical model described in the authors' previous studies [9].

Thermobaric conditions were calculated using an adapted Poettmann–Carpenter methodology tailored for ESP operating conditions [31–33].

The fluid temperature distribution along the wellbore was calculated using the methodology proposed in references [34,35]. The temperature distribution in the wellbore, at any section L in either the production casing (Equation (1)) or the tubing (Equation (2)), was determined accounting for heat exchange between the fluid flow and surrounding formations, as well as heat generation from the ESM operation [36,37]:

$$t_{cas} = t_{res} - \left(\frac{H_{top}}{\cos \alpha} - L \right) \frac{0.0034 + 0.79 \cdot G \cdot \cos \alpha}{10^{Q/(20 \cdot d_{cas.int}^{2.67})}}, \text{ } ^\circ\text{C} \quad (1)$$

$$t_{tub} = t_{res} - \frac{(H_{top} - H_{pump})}{\cos \alpha} \cdot \frac{0.0034 + 0.79 \cdot G \cdot \cos \alpha}{10^{Q/(20 \cdot d_{cas.int}^{2.67})}} - \left(\frac{H_{pump}}{\cos \alpha} - L \right) \frac{0.0034 + 0.79 \cdot G \cdot \cos \alpha}{10^{Q/(20 \cdot d_{tub.int}^{2.67})}}, \text{ } ^\circ\text{C} \quad (2)$$

where t_{res} —reservoir temperature, $^\circ\text{C}$; α —average well deviation angle, degrees; G —geothermal gradient, $^\circ\text{C}/\text{m}$; H_{pump} —vertical depth of pump setting, m; H_{top} —vertical depth of reservoir top, m; Q —liquid flow rate, m^3/day ; $d_{cas.int}$ —internal diameter of production casing, m; and $d_{tub.int}$ —internal diameter of tubing, m.

The optimization criterion was to maximize the upward shift in the onset depths of deposit formation along the wellbore. The GHD onset depth was defined as the intersection between the wellbore thermobaric profile and the equilibrium hydrate formation curve; for ARPD, the wellbore thermogram was compared with the distribution curve of paraffin saturation temperature of crude oil [38,39].

The effects of downhole operating parameters on the onset depths of ARPD and GHD formation were systematically evaluated. Specifically, the influence of pump setting depth, ESM operating frequency, internal tubing diameter, and wellhead choke diameter was analyzed. Calculations were performed for the ESP-125-1050 pump.

Simulation results (Figure 1) showed that increasing the pump setting depth by 100 m reduces the onset depth of hydrate formation by 7% and ARPD formation by 2%.

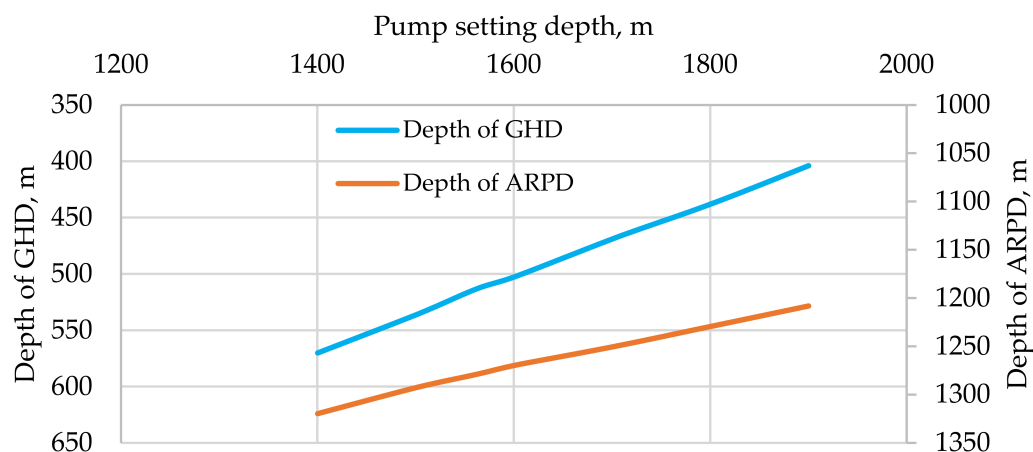


Figure 1. Dependence of the onset depth of ARPDs and GHDs on ESP setting depth.

The influence of ESM operating frequency on the onset depths for both types of deposits was also investigated (Figure 2). Changing the operating frequency redistributes the pressure and temperature profiles along the wellbore and alters the amount of free gas at the pump intake. Modeling showed that increasing the motor frequency by 5 Hz reduces the onset depth of hydrate formation by 5% and ARPD formation by 0.5%.

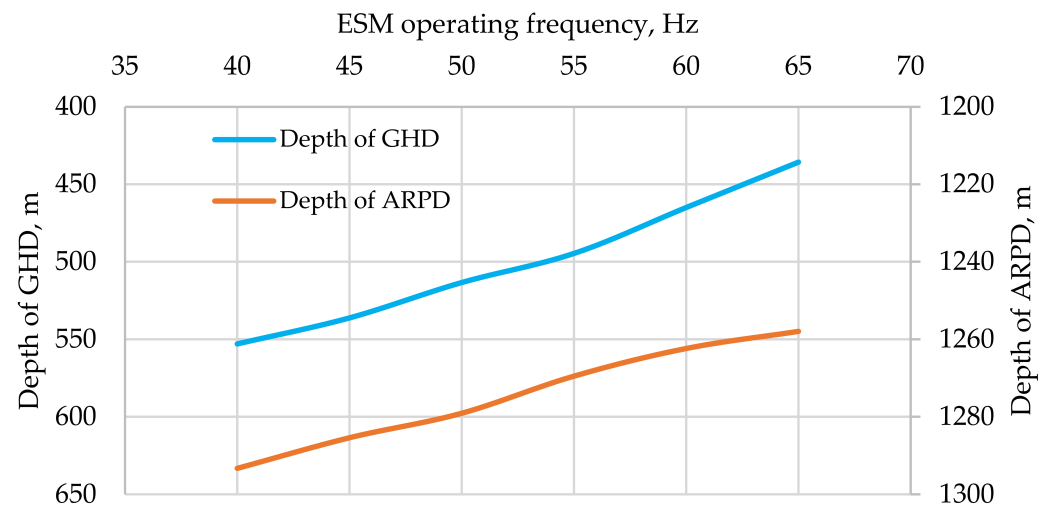


Figure 2. Dependence of the onset depth of ARPDs and GHDs on ESM operating frequency.

Furthermore, modeling revealed that installing a wellhead choke (with a diameter less than 10–12 mm) increases the onset depth of GHD formation by 300 m due to increased wellhead pressure and the throttling effect, despite a slight reduction (by 40 m) in the ARPD onset depth (Figure 3). However, the increased material requirements and the need for a workover during installation outweighed this benefit; therefore, choke installation was considered impractical.

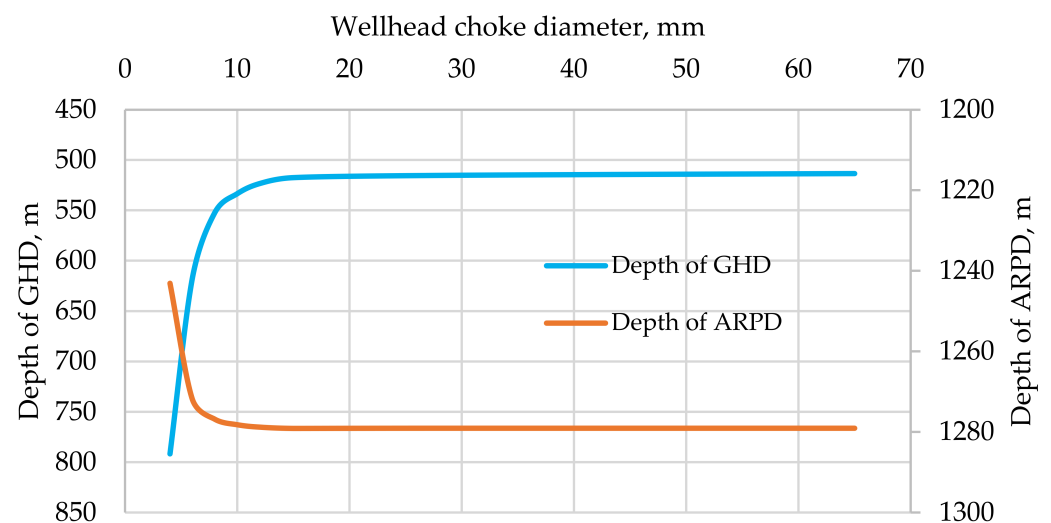


Figure 3. Dependence of the onset depth of ARPDs and GHDs on wellhead choke diameter.

Finally, the influence of internal tubing diameter was evaluated. Changing the internal tubing diameter affects both the fluid temperature profile and flow characteristics. The relationship presented in Figure 4 shows that decreasing the internal tubing diameter reduces the onset depth of both ARPD and GHD formation.

Decreasing the internal tubing diameter by 5 mm reduces the onset depth of hydrate formation by an average of 20% and ARPD formation by 3.5%. However, replacing the entire tubing string significantly alters the hydrocarbon production regime, which requires techno-economic justification for the intervention and a workover operation.

Based on these results, the optimal operating regime was identified as setting the ESP-125-1050 pump at a depth of 1800 m and operating at a frequency of 60 Hz. This regime ensures the required bottomhole pressure, reduces the gas fraction at the pump

intake, and minimizes the risks of deposit formation by modifying the temperature and pressure profile within the tubing.

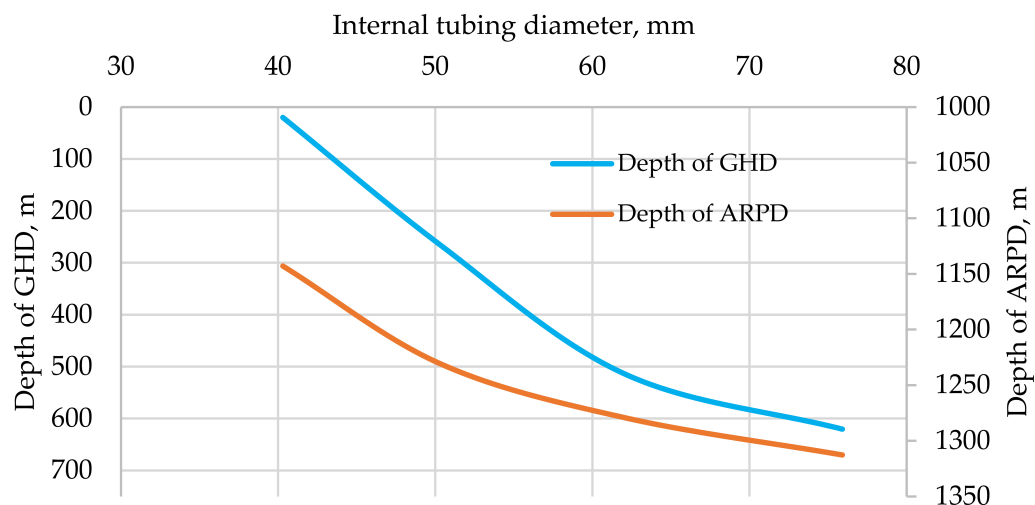


Figure 4. Dependence of the onset depth of ARPDs and GHDs on internal tubing diameter.

2.3. Inhibitor Dosage Calculation

An engineering calculation was performed to determine the optimal dosages of chemical inhibitors for preventing the simultaneous formation of ARPDs and GHDs under the optimized ESP operating conditions [12]. The ARPD inhibitor consists of a mixture of an ethylenediamine-based block copolymer of ethylene and propylene oxides (45 wt.%) and methanol (55 wt.%). For thermodynamic inhibition of gas hydrates, commercial-grade methanol (97 wt.% purity) is used without additional additives. The methodology for calculating the required dosages of these reagents is detailed in the following subsections.

2.3.1. Methodology for Calculating Dosage of Thermodynamic Hydrate Inhibitor

The required mass concentration of methanol in the aqueous solution (ω , wt.%) was calculated based on the necessary shift in the equilibrium hydrate formation temperature using Equation (3) [14,16,40]:

$$\Delta T = T_{hydr} - T_{wh}, \text{ K} \quad (3)$$

where T_{hydr} —hydrate formation temperature, K; T_{wh} —flow temperature at the wellhead, K.

For the investigated well, the onset temperature of crystal hydrate formation was $T_{hydr} = 289.4$ K, while the flow temperature at the wellhead was $T_{wh} = 279.16$ K. Thus, the required temperature shift was $\Delta T = 10.24$ K. The theoretical methanol concentration required to achieve this temperature reduction, calculated using Equation (4), was 20.2 wt.%.

$$\omega = 100 \cdot \left(\frac{32 \cdot \Delta T}{32 \cdot \Delta T + 1295} \right), \text{ wt.}\% \quad (4)$$

where ΔT is the required change in hydrate formation temperature, K.

Accounting for a safety factor of 1.2 (to compensate for uneven injection and inhibitor losses), the practical concentration of methanol in the aqueous phase was set at $C_2 = 24.23$ wt.%.

The required methanol dosage (G , g/m³) was determined using Equation (5):

$$G = \frac{DW \cdot C_2}{C_1 - C_2} + \left(\frac{100 - C_2}{C_1 - C_2} \right) \cdot q_g, \text{ g/m}^3 \quad (5)$$

where C_1 is the initial concentration of injected methanol (97 wt.%); DW is the amount of liquid water contained in the gas, g/m^3 ; and q_g is the equilibrium methanol content in the gas phase, g/m^3 .

The moisture content of the gas flow (W , g/m^3), accounting for the presence of methanol, was calculated using Equation (6):

$$W = [1 - (9 \cdot C_2) / (1600 - 7 \cdot C_2)] \cdot \left(\frac{A}{P} + B \right), \text{g}/\text{m}^3 \quad (6)$$

where A and B are empirical coefficients depending on temperature, determined for the specific field; P is pressure, MPa.

The coefficients A and B were calculated using Equations (7) and (8):

$$A = 0.457 \cdot \exp(0.07374 \cdot t - 0.000307 \cdot t^2) \quad (7)$$

$$B = 0.0418 \cdot \exp(0.0537 \cdot t - 0.000199 \cdot t^2) \quad (8)$$

where t is the temperature of the gas–liquid mixture at the point of interest, $^{\circ}\text{C}$.

For the ESP intake conditions, the gas moisture content was $W_1 = 1.44 \text{ g}/\text{m}^3$, and at the wellhead, $W_2 = 0.32 \text{ g}/\text{m}^3$.

The amount of liquid water contained in the gas (DW) was determined using Equation (9) as the difference in moisture contents, corrected for the presence of methanol:

$$DW = W_1 - W_2 \left[1 - \frac{9 \cdot C_2}{1600 - 7 \cdot C_2} \right], \text{g}/\text{m}^3 \quad (9)$$

The amount of liquid water contained in the gas was $1.17 \text{ g}/\text{m}^3$.

The equilibrium methanol content in the gas phase (q_g) was determined using nomograms [1,25] for wellhead conditions ($P = 2.2 \text{ MPa}$, $t = 6^{\circ}\text{C}$) and was $0.85 \text{ g}/\text{m}^3$.

The calculated methanol dosage was therefore $1.278 \text{ g}/\text{m}^3$. Accounting for a normative margin of 10–20% to compensate for uneven injection by dosing units, the final inhibitor consumption was set at $G = 1.53 \text{ g}/\text{m}^3$ (or 0.0019 L of methanol per 1 m^3 of gas).

2.3.2. Justification of the Periodic Methanol Injection Regime

A key feature of the developed technology is the transition from continuous to periodic injection of the thermodynamic hydrate inhibitor (methanol). This approach became feasible because of the kinetic properties of the selected ARPD inhibitor, which—because it contains high-molecular-weight surfactants—increases the nucleation time of gas hydrates by an average of 50 min at a mass concentration of 0.055% in the aqueous phase [7,41].

To determine an appropriate injection interval, the transit time of the gas–liquid mixture (GLM) from the pump intake to the wellhead was calculated. The GLM velocity was determined using Equation (10):

$$C_{GLM} = \frac{v + q}{f} \quad (10)$$

where q is the volumetric liquid flow rate, m^3/s ; v is the volumetric gas flow rate, m^3/s ; and f is the internal cross-sectional area of the tubing, m^2 .

For the optimized well operating regime, the GLM velocity was calculated to be $15.1 \text{ m}/\text{s}$. Using the pump setting depth (1800 m) and the calculated hydrate onset depth (353.9 m), the transit time through the active hydrate formation interval was determined as $t_{hydr} = 34 \text{ s}$, whereas the total lift time from the pump intake to the wellhead was $t_{ESP} = 174 \text{ s}$.

Comparing the hydrate nucleation time with the flow transit time through the hazardous interval makes it possible to determine the appropriate thermodynamic hydrate inhibitor injection regime.

2.4. Implementation Scheme of the Inhibition Technology

The developed inhibition technology is implemented using a reagent dosing unit (RDU), which ensures precise delivery of chemical inhibitors to the ESP intake. Two inhibitor injection methods were evaluated at the field under consideration [25,42]:

- **Injection into the annulus.** This method is simple and reliable; however, it is associated with significant inhibitor losses at the well bottom due to adsorption onto the casing walls and interaction with formation fluids.
- **Delivery via capillary tubing.** The inhibitor is delivered using special ports attached to the tubing string or the submersible power cable. This delivery method to the pump intake is characterized by lower inhibitor losses and allows more precise placement of the injection point.

In this study, the second method was selected as the most effective in terms of reagent consumption and technological feasibility. A schematic of the RDU integrated with the wellhead and downhole equipment is presented in Figure 5.

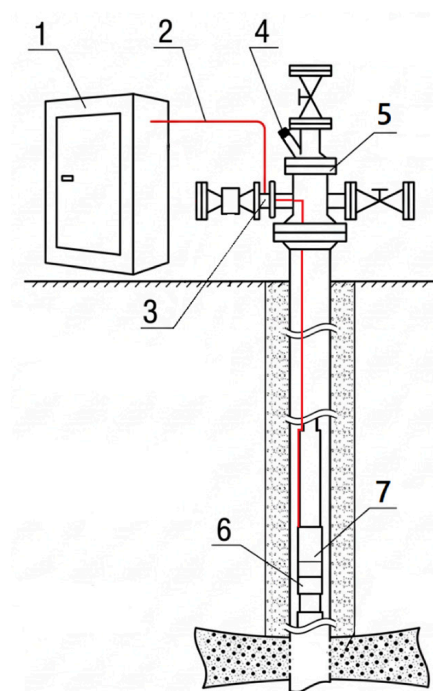


Figure 5. Schematic of the RDU integrated with wellhead and downhole equipment: 1—RDU cabinet; 2—inhibitor pipeline; 3—capillary tubing injection device via side outlet of the Christmas tree; 4—injection device via cable port of the Christmas tree; 5—Christmas tree; 6—spray valve; 7—capillary tubing clamp.

2.5. Refinement of the Algorithm for Calculating the Onset Depth of Deposits Accounting for the Kinetic Effect of Paraffin on Hydrate Formation

Traditional models for predicting the onset depth of gas hydrate formation are based on thermodynamic equilibrium and do not account for kinetic delays in the nucleation process. However, laboratory studies conducted within the framework of studies [9,43] demonstrated that the presence of paraffinic hydrocarbons in the oil–gas–water system delays hydrate nucleation. At a paraffin content of 7 wt.%, the nucleation time increases by 7.8%, suggesting that paraffin acts as a natural kinetic inhibitor.

These findings require refinement of the algorithm for calculating the onset depth of active hydrate formation. If thermodynamic conditions are reached at a certain depth, actual hydrate formation occurs higher in the wellbore, as the GLM requires time to overcome the induction period.

The modified algorithm proposed in references [9,44] is summarized below:

1. The GLM ascent velocity in the tubing is calculated using Equation (10), as presented in Section 2.3.2.
2. The onset depth of hydrate formation is described by Equation (11):

$$H_{hydr} = f[P(H), T(H), Q, G(H), C_{gasi}] \quad (11)$$

where $P(H)$ is the pressure distribution along the depth, MPa; $T(H)$ is the temperature distribution along the depth, °C; Q is the well flow rate, m³/s; $G(H)$ is the gas content distribution along the depth, m³/m³; and C_{gasi} is the component composition of the gas, fractions.

3. The transit time through the predicted hydrate formation interval, determined by the original model, is calculated using Equation (12):

$$H_{hydr} = \frac{Q_{GLM} \cdot 4}{\pi \cdot d_{tub.int}^2} \cdot t \quad (12)$$

where Q_{GLM} is the gas–liquid mixture flow rate, m³/s; $d_{tub.int}$ is the internal tubing diameter, m; and t is the transit time of the GLM through the hydrate formation interval, s.

4. A nucleation delay coefficient K_{nucl} is introduced, determined experimentally as the ratio of the nucleation time in a pure system ($t_{nucl, init}$) to the nucleation time in the presence of paraffin ($t_{nucl, par}$) (Equation (13)):

$$K_{nucl} = \frac{t_{nucl, init}}{t_{nucl, par}} \quad (13)$$

For the considered model oil, the value of K_{nucl} is 0.922.

5. The adjusted transit time through the hydrate formation zone t' is determined using Equation (14), which is then substituted into Equation (12):

$$t' = K_{nucl} \cdot t \quad (14)$$

6. The refined onset depth of active hydrate formation (Equation (12)) is calculated accounting for the fact that the GLM rises higher before the onset of active gas hydrate crystallization.

Model verification was performed for the studied well with the initial downhole equipment configuration. For the initial well parameters (ESP-200-1350, pump setting depth 1562 m), the thermodynamic model predicted the onset of hydrate formation at a depth of 194.7 m. After accounting for the kinetic effect, the predicted hydrate onset depth shifted upward by 15.2 m (Figure 6), from 194.7 to 179.5 m. The reduction in the hydrate formation onset depth by 8.4% in the presence of paraffinic particles indicates that conventional thermodynamic models overestimate the hydrate formation risk because they neglect the inhibitory effect of paraffin.

The refined model was adopted as the basis for all subsequent technological calculations. The curves shown in Figure 6 are based solely on numerical simulations. Experimental validation of the predicted onset depths through pilot field testing is planned as the next stage of this research.

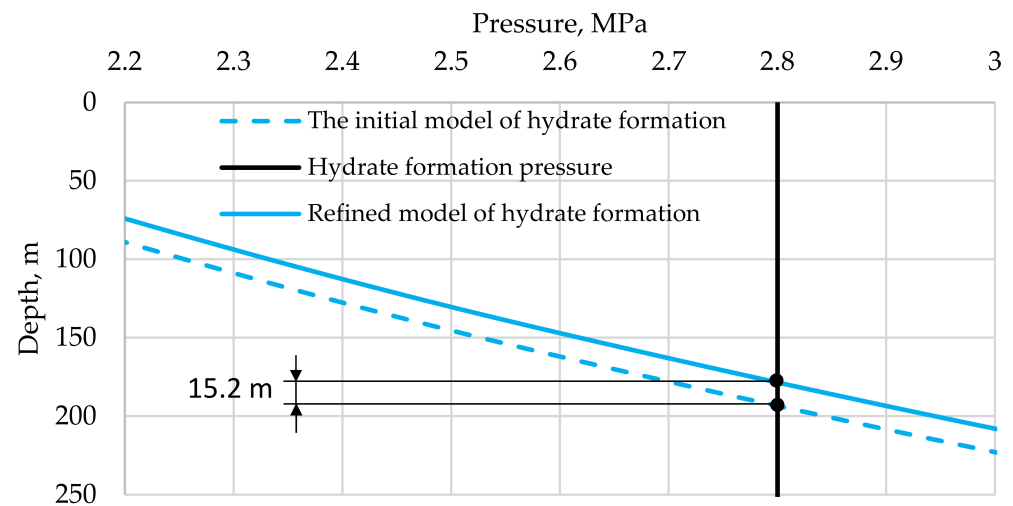


Figure 6. Reduction in the calculated onset depth of hydrate formation due to the kinetic effect of paraffinic particles in the system.

3. Results

3.1. Optimization of ESP Operating Parameters and Displacement of Deposit Formation Onset Depths

The first stage of the study focused on optimizing the operating parameters of the downhole equipment to minimize the onset depths of ARPD and GHD formation. The initial well configuration, which employed an ESP-200-1350 pump operating under an intensified production regime (flow rate of $110.4 \text{ m}^3/\text{day}$ and bottomhole pressure of 3.56 MPa), was replaced with an optimized configuration incorporating an ESP-125-1050 pump installed at a depth of 1800 m and operated at 60 Hz . The optimized ESP operating parameters were selected based on the relationships presented in Section 2.2. These relationships enable the selection of operating parameters that minimize the risk of ARPD and GHD formation.

Thermobaric calculations showed that the GHD formation onset depth shifted upward by 119.4 m (25%), reaching a new depth of 353.9 m . Optimization of the downhole equipment operating parameters shifted the ARPD formation onset depth upward by 72.6 m (6%), to 1206.5 m . These changes are illustrated in Figures 7 and 8.

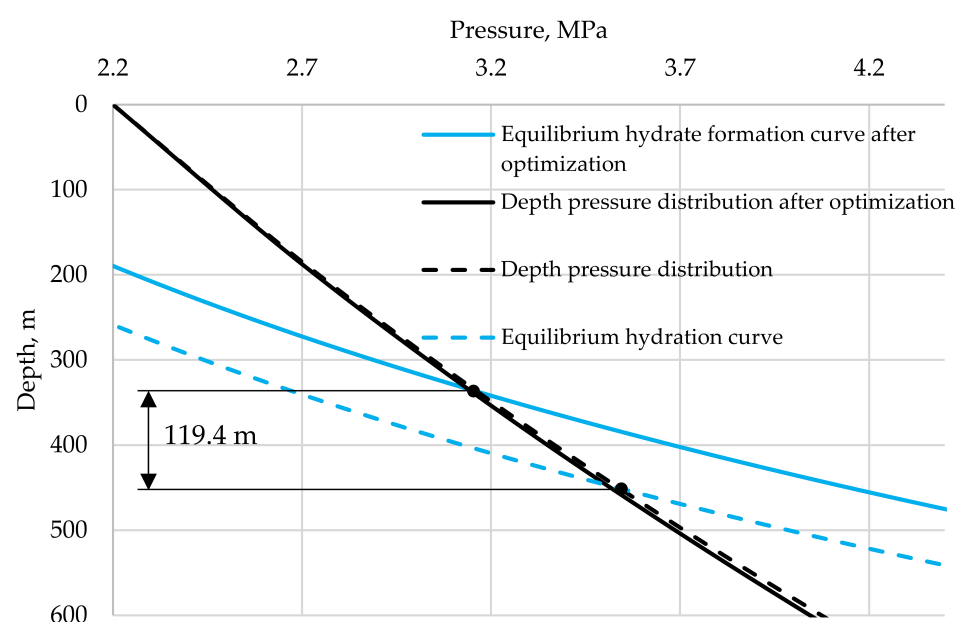


Figure 7. Thermobaric conditions of hydrate formation in the studied well before and after optimization of downhole equipment operating parameters.

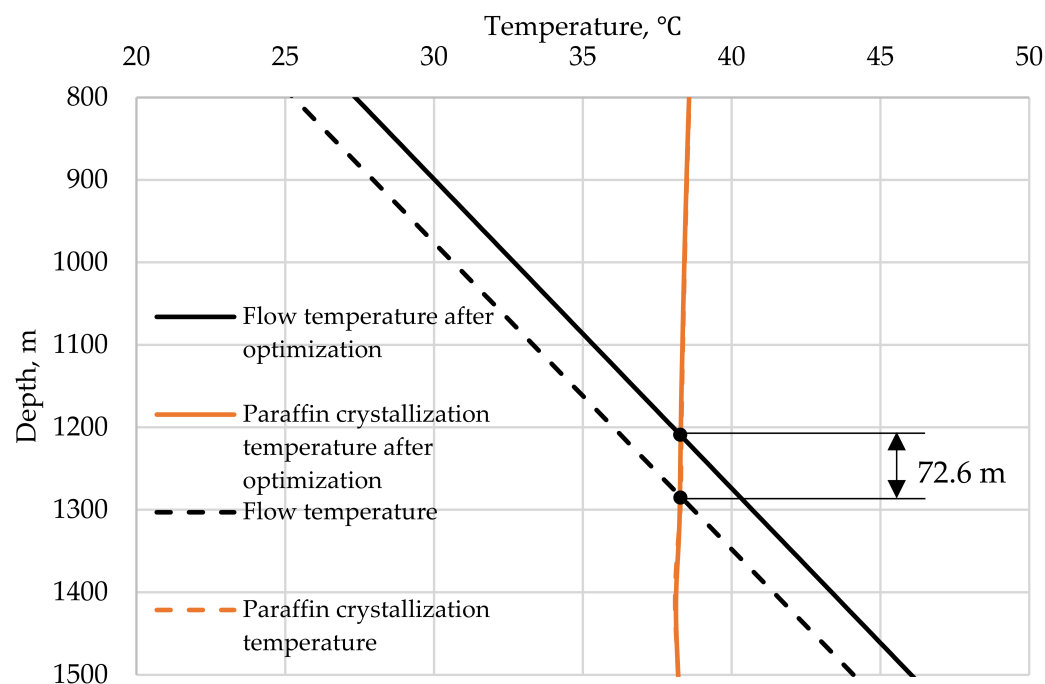


Figure 8. Well thermogram and distribution of paraffin crystallization temperature of crude oil before and after optimization of downhole equipment operating parameters.

Additionally, the refined model predicts a further upward shift of approximately 30 m in the hydrate formation onset depth. This refinement has already been incorporated into the presented results.

The optimized operating regime achieved the target production rate of 90.21 m³/day while increasing the bottomhole pressure to 8.72 MPa. These changes improved ESP operating conditions, and eliminating the intensified production regime reduced the risk of premature water breakthrough.

3.2. Calculation of Hydrate Inhibitor and ARPD Inhibitor Dosages Accounting for Their Synergistic Effect

Laboratory experiments described in our previous study [7] demonstrated that the selected ARPD inhibitor exhibits both kinetic and thermodynamic hydrate inhibition properties.

At a concentration of 0.055 wt.% in the aqueous phase, the inhibitor reduced the equilibrium hydrate formation temperature by $\Delta T = 0.55$ °C. This effect further reduced the required methanol dosage.

To evaluate the combined effect, three dosage scenarios were calculated:

1. Original ESP configuration (without optimization);
2. Optimized ESP operating conditions;
3. Optimized ESP operating conditions with the selected ARPD inhibitor.

Table 2 shows that the integrated approach—combining ESP optimization with the selected ARPD inhibitor—reduced the initial methanol dosage by 12.17% (from 1.66 to 1.46 g/m³). The reduction resulted from two complementary effects. Optimizing the well thermobaric conditions reduces the required temperature shift by 26%. The selected ARPD inhibitor provides an additional 4% reduction.

The ARPD inhibitor dosage was calculated using Equation (15):

$$C_{g/m^3} = \frac{C_{\%} \cdot \rho}{100} \cdot K, \text{ g/m}^3 \quad (15)$$

where C_{g/m^3} is the ARPD inhibitor concentration in g/m³; ρ is the solution density (kg/m³); $C_{\%}$ is the mass concentration (0.055%); and K is the safety factor (equal to 1.2).

The recommended inhibitor dosage was 0.66 g per 1 m³ of produced water. The inhibitor was continuously injected through a capillary tubing system mounted externally on the production tubing string.

Table 2. Results of calculations for parameters determining methanol dosage.

Calculation Parameter	Original ESP	Optimized ESP	Optimized ESP + Selected ARPD
ΔT , K	13.81	10.24	9.69
C_2 , wt. %	30.53	24.23	23.18
G , g/m ³	1.66	1.53	1.46
Dosage change, %	0	−7.62	−12.17

3.3. Selection of Periodic Injection Regime for Gas Hydrate Inhibitor

Comparison of the hydrate nucleation time (50 min) with the flow transit time through the hazardous interval (34 s) showed that continuous methanol injection was unnecessary. Based on this analysis, the following dosing scheme was proposed:

- Methanol was injected for 2 min at a dosage of 1.46 g/m³ of gas, followed by a 30 min pause. The cycle was then repeated.
- The selected ARPD inhibitor was injected continuously at a dosage of 0.66 g/m³ of produced water to ensure reliable removal of ARPD.

A 30 min pause was selected, corresponding to a 40% safety margin relative to the extended hydrate nucleation time (50 min). This ensures that the fluid parcel leaves the hazardous interval before significant hydrate crystal accumulation can occur on the tubing wall. The proposed injection scheme maintains the required methanol concentration in the hydrate formation zone (23.18 wt. % in the aqueous phase) while significantly reducing the total reagent consumption. Periodic methanol injection reduced reagent consumption and associated storage and transportation costs while improving the environmental sustainability of the inhibition process.

3.4. Assessment of Changes in Well Mean Time Between Failures

MTBF was predicted using a multiple regression model based on statistical analysis of ESP operating data [45,46]. The baseline MTBF for the studied well was 277 days, based on field observations.

For calculation purposes, an influence coefficient for various well equipment operating parameters on MTBF was introduced, determined by Equation (16):

$$k_{x_i} = \frac{MTBF(x_i')}{MTBF(x_i)} \quad (16)$$

where x_i is the investigated well equipment operating parameter; $MTBF(x_i)$ is the dependence of the average MTBF for ESP-equipped oil wells in the West Siberian petroleum province on the initial value of parameter x_i , days; and $MTBF(x_i')$ is the dependence of the average MTBF on the value of parameter x_i after optimization, days.

The change in MTBF was calculated by considering the influence of the following optimized operating parameters:

- Free gas content at the pump intake decreased to 22.5% ($k_1 = 1.113$);
- Pump equipment temperature decreased from 116.7 °C to 86.2 °C ($k_2 = 1.578$);
- Pressure at the pump intake increased from 2.22 MPa to 7.53 MPa ($k_3 = 1.899$);
- Pump setting depth was increased to 1800 m ($k_4 = 0.847$).

The final MTBF was calculated as the product of the baseline MTBF and the combined influence coefficient of all optimized parameters, yielding a predicted MTBF of 419 days. This corresponds to an increase of 142 days (50%) relative to the baseline configuration.

The main factors contributing to the MTBF improvement were:

1. Optimization of the pump equipment temperature regime (reduced thermal degradation of seals and overall equipment wear);
2. Improved pump intake pressure conditions (reduced cavitation loads on impellers);
3. Reduced free gas content (decreased supply surges and vibration loads).

Overall, comprehensive optimization of ESP operating conditions under simultaneous ARPD and GHD formation substantially improved equipment reliability and extended the well's trouble-free operating period.

3.5. Economic Efficiency Assessment of the Inhibitory Technology Application

The economic performance of the proposed technology was evaluated over an 8-year period corresponding to the service life of the ESP. The key performance indicators used were net present value (NPV), profitability index (PI), and discounted payback period (DPP) [47,48].

The economic benefits were derived from three main sources:

- **Reduced methanol consumption costs:** Annual expenses decreased from 209,792 RUB/year to 12,277 RUB/year (savings $B_1 = 197,514$ RUB/year). The savings resulted from optimization of methanol dosage (−12.17%) and transition to periodic injection, resulting in a substantial reduction in thermodynamic hydrate inhibitor consumption.
- **Reduced frequency of planned workovers:** from 1.32 to 0.87 events per year (savings $B_2 = 293,618$ RUB/year).
- **Elimination of costs for mechanical and thermal well treatments** aimed at deposit removal ($B_3 = 500,000$ RUB/year).

The total annual economic benefit amounted to $B = 991,132$ RUB/year. The required capital investment in the project (acquisition of additional tubing strings to increase pump setting depth) totaled 858.25 thousand RUB.

The results of the economic analysis are presented in Table 3.

The positive NPV confirms the economic viability of the proposed technology. The cumulative discounted cash flow over the project life is shown in Figure 9.

The proposed technology not only reduces operating costs but also improves ESP reliability and production efficiency, making it attractive from both technical and economic perspectives.

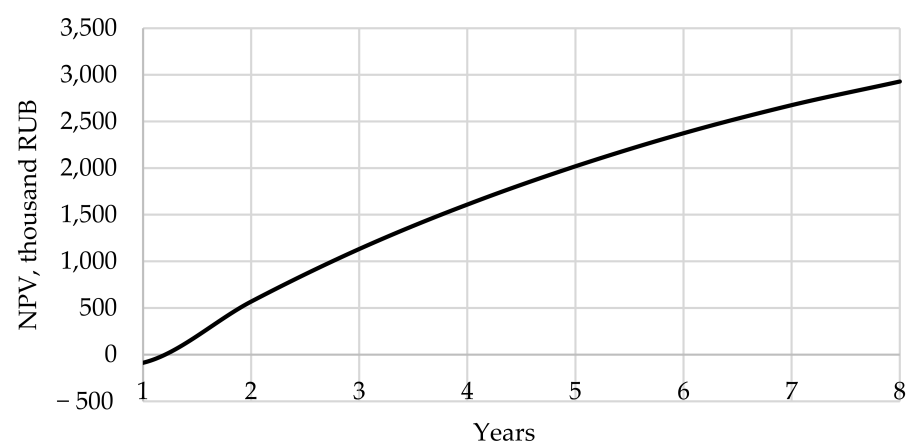


Figure 9. NPV dynamics over project implementation years.

Table 3. Project efficiency analysis.

Indicator	Value
Net present value (NPV), thousand RUB	2929.65
Profitability index (PI)	4.41
Discounted payback period (DPP)	1 year 2 months

4. Discussion

The results demonstrate the effectiveness of the proposed comprehensive approach for preventing the simultaneous formation of ARPDs and GHDs in ESP-operated oil wells. These findings are consistent with previous studies on hydrate formation kinetics [12,41,44] and support the proposed synergistic interaction between methanol and the selected ARPD inhibitor.

4.1. Interpretation of ESP Operating Parameter Optimization Results

Optimizing the downhole equipment operating parameters—including replacement of the ESP-200-1350 with the ESP-125-1050, increasing the pump setting depth to 1800 m, and raising the ESM operating frequency to 60 Hz—shifted the onset depths by 119.4 m for GHDs and 72.6 m for ARPDs. These findings agree with previous studies [46,49], which showed that increasing bottomhole pressure and optimizing the wellbore temperature profile reduce oil degassing and consequently decrease the risk of paraffin crystallization and hydrate formation.

An important engineering decision was to avoid installing a wellhead choke. Although it slightly reduced the ARPD onset depth, it increased the hydrate formation onset depth by 300 m. This observation is consistent with the conclusions of reference [50], which indicate that flow throttling under low-temperature conditions may promote gas hydrate plug formation.

Although developed for ESP-operated wells, the proposed optimization algorithm is not limited to this production method. Its modular structure—including parameter optimization, thermobaric modeling, deposit risk assessment, and economic evaluation—can readily be adapted to other artificial lift systems operating under complex multiphase flow conditions [46].

4.2. Synergistic Effect of Comprehensive Inhibition

One of the principal findings of this study is the quantitative demonstration of the synergistic effect resulting from the combined application of methanol and the selected ARPD inhibitor. The observed 12.17% reduction in methanol dosage resulted from two complementary mechanisms:

1. **Thermodynamic inhibition.** The presence of methanol in the selected ARPD inhibitor formulation causes an additional shift in the equilibrium hydrate formation curve by $\Delta T = 0.55\text{ }^{\circ}\text{C}$, which is consistent with the data reported in reference [12].
2. **Kinetic inhibition.** The high-molecular-weight surfactant (ethylene–propylene oxide block copolymer) in the selected reagent adsorbs on the hydrate nucleus surface, increasing the nucleation time by 7.5%. This kinetic effect made it possible to reduce the required methanol dosage and implement a periodic methanol injection regime.

Unlike conventional approaches based on separate inhibition [14,24,25], the proposed technology integrates thermodynamic and kinetic inhibition within a single treatment strategy. As a result, it reduces both operating costs and the environmental footprint of hydrate prevention. Beyond oil production, this concept may also be applicable to gas storage facilities [21], LNG supply chains [51], and other industrial systems where hydrate or mineral scale formation presents operational challenges.

4.3. Application Area of the Inhibitory Technology

The proposed inhibitory technology is applicable within a defined range of thermo-baric, physicochemical, and operational conditions. Table 4 summarizes the recommended application range of the proposed technology.

Table 4. Effective application range of the proposed inhibitory technology.

Parameter	Application Range
Reagent storage temperature, °C	above −45
Wellhead pressure, MPa	above 1
Paraffin content *, wt. %	above 6 (high-paraffin crude oil)
Asphaltene content *, wt. %	below 1 (low-resin crude oil)
Water mineralization *, g/L	up to 5
Water cut *, %	above 5
Gas–oil ratio *, m ³ /m ³	above 50
Well production method	ESP
ARPD inhibitor solubility	water-soluble

Note: Parameters marked with an asterisk require additional research when exceeding the specified boundaries.

These applicability limits are governed by the following technological and physico-chemical considerations:

- **Temperature range.** The minimum reagent storage and injection temperature is limited by the pour point of the ARPD inhibitor (−50 °C). To ensure reliable RDU operation, a safety margin of 5 °C was adopted. This prevents excessive viscosity increases that would otherwise increase hydraulic resistance within the capillary tubing. Thus, the minimum operating temperature was set at −45 °C. At lower temperatures, reagent heating or formulation modification is required.
- **Wellhead pressure.** The technology is recommended for wells with wellhead pressure above 1 MPa. This limitation arises from hydrate formation thermodynamics. Field statistics from Arctic wells indicate that at pressures below 1 MPa, the probability of stable gas hydrate plug formation in the wellbore significantly decreases even without intensive inhibition.
- **Paraffin content.** The synergistic inhibition mechanism becomes significant when the paraffin content exceeds 6 wt. % (high-paraffin crude oil). Laboratory studies have demonstrated that at such concentrations, paraffin crystals begin to influence mass transfer at the phase interface, increasing hydrate nucleation time.
- **Produced water cut.** The minimum water cut threshold is set at 5%. This threshold reflects the mechanism of action of the selected ARPD inhibitor, which is a water-soluble surfactant.

The proposed technology is intended for ESP-operated wells, in which heat generated by the ESM and the associated flow characteristics are explicitly incorporated into the deposit prediction model. Operation outside these limits does not preclude application of the technology. However, it reduces prediction reliability and requires additional laboratory validation to optimize inhibitor dosage and injection strategy.

The applicability limits summarized in Table 4 represent not only field-specific constraints but also broader physicochemical limitations of surfactant-based inhibition in multiphase systems [52]. Consequently, they may serve as practical guidelines for adapting the proposed methodology to reservoirs with different fluid compositions and operating conditions [53].

4.4. Research Limitations and Prospects for Further Work

Although the proposed technology demonstrated promising performance, several limitations should be acknowledged:

1. The results were obtained for a single candidate well, which limits the scalability of the proposed measures.
2. The long-term effects of ARPD inhibitor application on the corrosive activity of the environment and its compatibility with other chemical reagents used at the field have not yet been evaluated.
3. When water mineralization exceeds 5 g/L, a decrease in surfactant efficiency due to salting-out effects may occur, which may require additional adjustment of the inhibitor formulation.

Future work should focus on:

- Evaluating new inhibitor formulations and their influence on the kinetics of simultaneous ARPD and gas hydrate formation.
- Field testing of the technology on a representative sample of wells with diverse geological and technical conditions.
- Integrating the proposed methodology into digital well twins for real-time prediction of ARPD and GHD formation risks.

5. Conclusions

This study developed and validated an inhibitory technology for preventing the simultaneous formation of ARPDs and GHDs in ESP-operated oil wells. Using a comprehensive approach combining optimization of ESP operating parameters with chemical inhibition accounting for synergistic effects, the following main findings were obtained:

1. **Optimization of ESP operating parameters.** Replacing the ESP-200-1350 with an ESP-125-1050, increasing the pump setting depth to 1800 m, and raising the ESM operating frequency to 60 Hz shifted the GHD onset depth upward by 119.4 m (25%) and the ARPD onset depth by 72.6 m (6%). Bottomhole pressure was increased from 3.56 to 8.72 MPa, improving reservoir operating conditions.
2. **Synergistic inhibition strategy.** Application of the selected ARPD inhibitor together with methanol produced a synergistic inhibition effect, reducing the required methanol dosage by 12.17% for the studied well.
3. **Periodic injection regime.** The kinetic properties of the selected ARPD inhibitor increased hydrate nucleation time by approximately 50 min, making it possible to replace continuous methanol injection with a periodic regime (2 min injection followed by a 30 min pause), thereby reducing inhibition costs.
4. **Improved well reliability.** The predicted MTBF for the well increased from 277 to 419 days (by 50%), mainly resulting from optimization of the pump equipment temperature regime, reduced free gas content at the pump intake, and improved intake pressure conditions.
5. **Economic performance.** Economic analysis over an 8-year period demonstrated high economic viability for implementing the technology: NPV reached 2929.65 thousand RUB, and DPP was 14 months. Annual savings approached 1 million RUB per well.
6. **Recommended application range.** The proposed technology is recommended for ESP-operated wells producing high-paraffin, low-resin crude oil (paraffin content > 6 wt.%), with water cuts above 5% and gas–oil ratios exceeding 50 m³/m³ under permafrost conditions.

The proposed technology provides a practical framework for mitigating the simultaneous formation of ARPDs and GHDs in Arctic ESP-operated wells. Future research should focus on field-scale validation, evaluation of alternative inhibitor formulations, and adaptation of the methodology to a wider range of geological and operating conditions.

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Abbreviations

The following abbreviations are used in this manuscript:

ARPD	asphalt–resin–paraffin deposit
GHD	gas hydrate deposit
GLM	gas–liquid mixture
MTBF	mean time between failures
OGCF	oil and gas condensate field
ESP	electric submersible pump
ESM	electrical submersible motor
THI	thermodynamic hydrate inhibitor
RDU	reagent dosing unit
NPV	net present value
PI	profitability index
DPP	discounted payback period

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