

AN INTEGRATED PRESSURE COMPATIBILITY FRAMEWORK FOR OPTIMIZING WELL DESIGN AND DRILLING PARAMETERS IN A MATURE OIL FIELD – CASE STUDY FROM THE VATYOGANSKOYE FIELD, RUSSIA

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ABSTRACT

Well design in oil drilling requires a thorough analysis of geological conditions, formation pressures, and technical risks. The Vatyoganskoye field (Russia) features a complex sedimentary structure with potentially problematic carbonate intervals.

This study presents a systematic application of pressure compatibility analysis for integrated well design optimization in the Vatyoganskoye oil field. The contribution lies in combining geological characterization, pressure analysis, drilling-fluid design, casing selection, cementing planning, and drilling-parameter optimization within a unified engineering workflow.

The design is based on a combined coefficient plot (formation pressure anomaly coefficient k_a , lost circulation index k_{loss} , fracture pressure index k_{frac} , and mud relative density ρ_{rel}) to define compatibility zones. The novelty of this work lies in the integrated framework that links these dimensionless pressure coefficients directly to engineering decisions (casing depths, mud density, bit selection, cementing), providing a reproducible template for well design in mature fields. Casing and bit diameters are calculated from the bottom upward. Drilling parameters (weight on bit, rotary speed, flow rate) are determined per interval. Cementing operations are dimensioned with volume calculations, equipment count, and pressure estimates. The selected architecture comprises four strings: conductor (30 m), surface casing (1110 m), intermediate casing (1880 m), and production casing (2000 m). Bit diameters range from 558.8 mm to 187.3 mm. Roller-cone bits are selected according to rock categories (II to VII). Drilling fluids consist of a low-clay polymer mud (0–420 m) followed by a non-dispersed polymer mud (420–2000 m). Cementing requires two mixing units and two pumping units. The BU-2000/125 EBM rig is selected.

Fractured carbonate reservoirs, analyzed from experience in analogous fields (Yurubcheno-Tokhomskoye), present major risks of lost circulation and kicks. The proposed design incorporates safety margins but lacks specific features to manage such complications in real time. The coefficient-based compatibility analysis reveals a narrowing operational window with depth, justifying the selected casing depths. This study provides a reproducible framework for well design in similar geological settings and highlights the need to integrate risk anticipation for carbonate heterogeneities into conventional design workflows.

Keywords: well design optimization, pressure compatibility, drilling engineering, casing design, mature oil field

INTRODUCTION

The design of oil and gas wells is a critical phase that determines both the technical success of drilling operations and the long-term productivity of the reservoir [1]. A well-designed casing program, appropriate drilling fluid selection, and optimized drilling parameters are essential to prevent complications such as lost circulation, wellbore instability, and kicks [1]. The increasing complexity of geological targets, particularly in fractured and vuggy carbonate reservoirs, demands a more integrated approach that combines conventional engineering calculations with a thorough understanding of subsurface heterogeneities [2]. This study proposes an integrated pressure compatibility framework that combines dimensionless pressure coefficients (GOST-based) with a bottom-up well design workflow, enabling a systematic and reproducible approach to casing depth optimization.

The Vatyoganskoye oil field, located in the Surgut district of the Khanty-Mansi Autonomous Okrug, Russia, represents a typical West Siberian reservoir with a sedimentary cover comprising Jurassic, Cretaceous, Paleogene, and Quaternary deposits [3]. The field is characterized by a complex structural framework and presents specific challenges related to pressure regimes and lithological variations. Of particular interest are the carbonate intervals, which, based on experience from analogous fields such as the Yurubcheno-Tokhomskoye field, exhibit high-permeability fracture and vug systems that can lead to catastrophic mud losses and sudden gas-oil-water kicks [2],[4]. These complications directly impact drilling safety, well costs, and reservoir evaluation [2],[4].

This paper presents the design methodology for a 2000 m vertical production well at the Vatyoganskoye field. The study aims to: (1) provide a step-by-step engineering approach for casing design, bit selection, hydraulic optimization, and cementing; (2) assess the compatibility of the chosen design with the geological pressure profile; and (3) discuss the potential risks associated with drilling through carbonate intervals based on analog field experience. The methodology follows a bottom-up design approach, with calculations performed in accordance with Russian industry standards [5],[6], and established engineering practices [7],[5].

The paper is organized as follows: Section 2 describes the geological setting of the Vatyoganskoye field; Section 3 outlines the design methodology; Section 4 presents the key results, including casing architecture, drilling parameters, and cementing calculations; Section 5 discusses the implications of carbonate reservoir risks; Section 6 concludes with recommendations for future well designs in similar geological contexts.

GEOLOGICAL SETTING

Location and physiography

The Vatyoganskoye oil field is located in the Surgut district of the Khanty-Mansi Autonomous Okrug, Tyumen Region, Russian Federation, approximately 30 km east of Kogalym (Figure 1). The field is situated within the central part of the West Siberian Lowland, a weakly dissected, heavily swampy plain with absolute elevations ranging from +65 to +78 m. The climate is sharply continental, with average January temperatures of -9.2°C and July temperatures of $+18.1^{\circ}\text{C}$. Snow cover thickness reaches 70–80 cm in open areas and up to 1.5 m in forested zones. Permafrost is absent, but seasonal freezing depths can reach 3 m in certain areas [3].



Figure 1. Location map of the Vatyeganskoye oil field.

TECTONIC SETTING

The Vatyeganskoye field is located in the central tectonic domain of the West Siberian Plate, characterized by a pre-Jurassic basement and a Mesozoic-Cenozoic sedimentary cover. In tectonic terms, the field is confined to the North-Vartovskaya megaterrace (first order), complicated by the Vatyeganskaya anticlinal ridge (second order) [3]. Structural mapping of the pre-Jurassic basement reveals an irregularly shaped uplift with its central part elongated northwest–southeast, measuring approximately 26 km in length and 8 km in width. Peripheral areas exhibit smaller local uplifts ranging from 1.2×1.6 km to 3×4 km. The structural pattern shows gradual flattening upward through the sedimentary section, indicating inherited development [3].

Stratigraphy and lithology

The geological section of the Vatyeganskoye field is typical of the Latitudinal Ob region and comprises two main structural complexes: the pre-Jurassic basement (geosynclinal stage) and the Mesozoic-Cenozoic sedimentary cover (platform stage). The pre-Jurassic basement, encountered at depths of 3430–3649 m, consists of light gray, finely crystalline, fractured limestones of probable Permian age. No oil or gas shows have been recorded in these deposits [3]. The sedimentary cover includes Jurassic, Cretaceous, Paleogene, and Quaternary deposits (Table 1). The stratigraphy follows the Regional Stratigraphic Schemes of Mesozoic Deposits of Western Siberia, approved by the Interdepartmental Stratigraphic Committee in 1991 [3].

Formation names and indices follow the Regional Stratigraphic Schemes of Western Siberia [3]. The productive horizon of interest is the AB_{1–2} interval, located within the Aym Formation (Aptian stage) at a depth of approximately 2000 m. This interval is characterized by interbedded sandstones, siltstones, and silty clays with good reservoir properties.

Table 1. Simplified stratigraphic and lithological summary of the Vatyoganskoye field section.

Stratigraphic unit	Index	Depth interval (m)	Thickness (m)	Lithological description
Quaternary	Q	0–30	30	Coarse-grained sand with gravel, pebbles, boulders; sandy loam, clay, loam
Turta Formation	P ₃	30–60	30	Greenish-gray quartz sands and siltstones
Novomikhailovka Formation	P ₃ ²	60–175	115	Clays with siltstone interbeds
Tavda Formation	P ₃ ¹	225–420	195	Greenish-gray clays, opokas, glauconitic siltstones
Gan'kino Formation	K _{2m-d}	795–940	145	Gray clays with calcareous siltstone and marl interbeds
Berezovo Formation	K _{2k-km}	940–1080	140	Greenish-gray uniform clays with pyrite and siderite concretions
Kuznetsovo Formation	K _{2t}	1080–1110	30	Bituminous clays, slightly calcareous, massive
Pokur Formation	K _{2s} –K _{1a-al}	1110–1880	770	Light gray to gray sandstones, siltstones with subordinate clay interbeds; abundant plant detritus
Alym Formation	K _{1a}	1880–2000	120	Interbedding of silty clays, sandstones, and siltstones; gray, fine-grained, micaceous

Reservoir characteristics

The AB_{1–2} productive horizon exhibits the following parameters based on field data [3]:

- Depth to top: 2000 m,
- Total reservoir thickness: 104 m,
- Net oil-saturated thickness: 35 m,
- Formation pressure: 19.5 MPa,
- Gas-oil ratio: 100 m³/t,
- Expected flow rate: 100 m³/day.

The formation pressure gradient in the productive interval is normal to slightly anomalous, with anomaly coefficient $k_a=1.029$. Fracture gradients vary from 0.0165 to 0.020 MPa/m depending on depth (Table 2). These pressure characteristics are critical for well design, as they determine the permissible drilling fluid density window and casing setting depths.

Table 2. Formation pressure and fracture gradient data by interval.

Stratigraphic interval	Depth range (m)	Formation pressure gradient (MPa/m)	Fracture gradient (MPa/m)
Q–P ₃ ¹	0–420	0.0101	0.020
P ₃ ¹ –K ₂	420–1110	0.0101	0.020
K ₂ –K ₁	1110–1880	0.0101	0.017
K ₁	1880–2000	0.0101	0.0165

Unlike conventional workflows in which pressure analysis, casing design, drilling-fluid selection, and drilling parameters are often treated separately, this study integrates these elements into a unified engineering framework based on pressure compatibility analysis. The objective is not to introduce a new well-design theory but to demonstrate a structured methodology for improving design consistency and risk identification in complex drilling environments.

MATERIALS AND METHODS

This section presents the systematic approach used to design the 2000 m production well at the Vatyoganskoye field. The methodology follows a bottom-up design sequence, starting from the production casing and proceeding to surface intervals. All calculations comply with Russian industry standards [5],[6], and established drilling engineering practices [1],[7].

Study area and well description

The Vatyoganskoye oil field is located in the Surgut district of the Khanty-Mansi Autonomous Okrug, Tyumen Region, Russian Federation, approximately 30 km east of Kogalym (Figure 1). The field is situated within the central part of the West Siberian Lowland, a weakly dissected, heavily swampy plain with absolute elevations ranging from +65 to +78 m. A detailed geological description (stratigraphy, tectonics, reservoir characteristics) is provided in Section 2. The subject of this study is a vertical production well designed to reach a total depth of 2000 m, targeting the AB₁₋₂ productive horizon within the Alym Formation (Aptian stage). The well is designed for an expected flow rate of 100 m³/day with a gas-oil ratio of 100 m³/t. Key well parameters are summarized in Table 3.

Table 3. Well design parameters.

Parameter	Value
Well type	Vertical production well
Total depth	2000 m
Target horizon	AB ₁₋₂ (Alym Formation, Aptian)
Expected flow rate	100 m ³ /day
Gas-oil ratio	100 m ³ /t
Formation pressure	19.5 MPa
Reservoir thickness (net oil-saturated)	35 m

Methodological approach workflow

The methodological approach followed in this study is illustrated in Figure 2. The workflow follows a systematic, bottom-up sequence designed to ensure coherence between geological constraints, pressure regime analysis, and engineering decisions.

The process begins with geological data review (stratigraphy, tectonics, lithology, reservoir characteristics), which provides the foundation for all subsequent calculations. From these data, dimensionless pressure coefficients (k_a , k_{loss} , k_{frac} , ρ_{rel}) are calculated using Equations (1) – (5) [7].

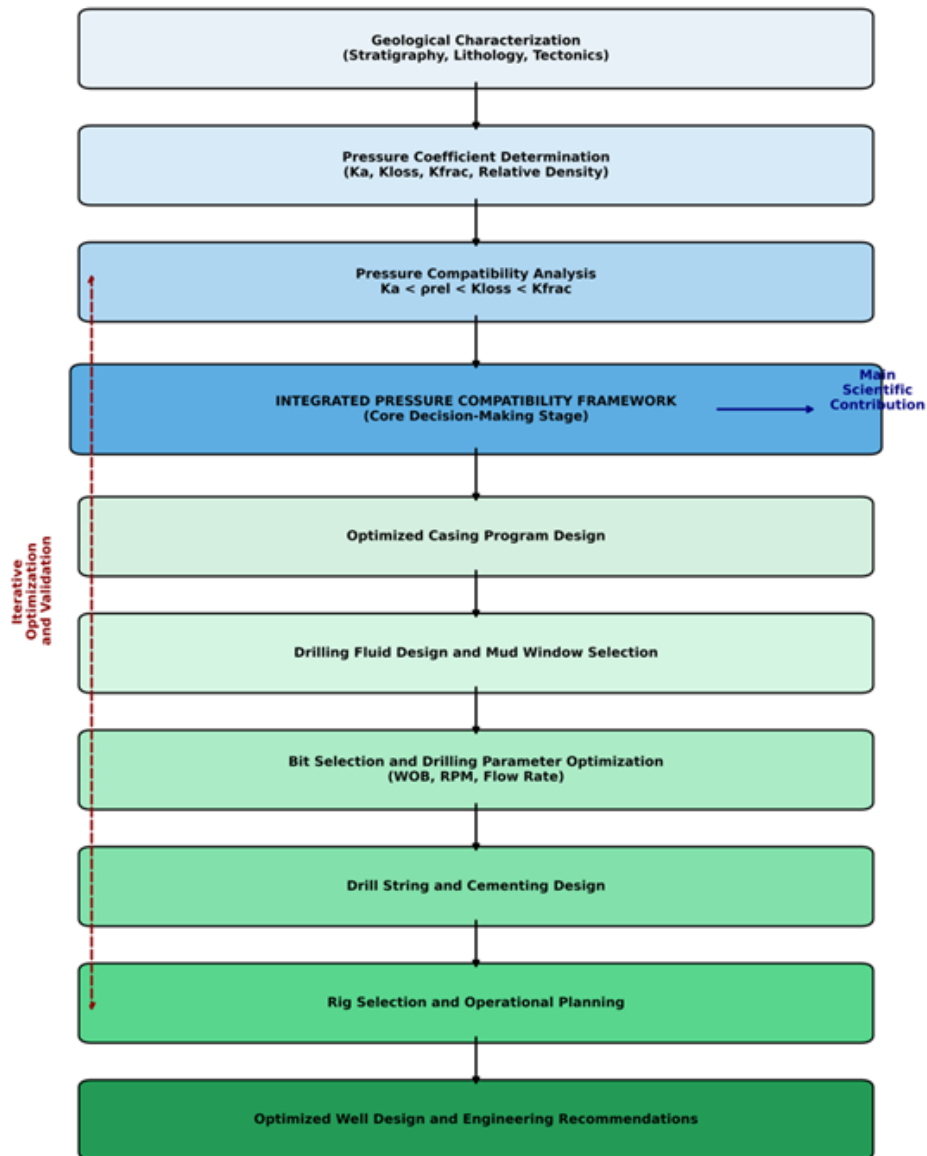


Figure 2. Methodological approach workflow for well design at Vatyoganskoye field.

A compatibility verification step ensures that the physical condition $k_a < \rho_{rel} < k_{loss} < k_{frac}$ is satisfied at all depths. This verification is visualized in the combined pressure plot, which also serves to determine optimal casing setting depths.

The workflow then proceeds through successive engineering steps: casing program design, bit selection, drilling fluid formulation, drilling parameters optimization, drill string design, cementing calculations, and rig selection. Each step is informed by the results of previous steps, creating an integrated design process.

Finally, a carbonate risk assessment is conducted using data from the Yurubcheno-Tokhomskoye field [4], an analog for fractured carbonate complications that may occur in the Pokur Formation (1110–1880 m) of the Vatyoganskoye field. This assessment informs recommendations for risk management.

The workflow is iterative, allowing adjustments to earlier steps as new constraints emerge during the design process. All calculations were implemented in Python 3.x within a Jupyter Notebook environment, enabling reproducibility and visualization.

Well design philosophy using pressure coefficients

The well design process begins with the selection of casing strings and their setting depths based on the identification of problematic zones (e.g., loss circulation zones, unstable formations, abnormally pressured intervals) and intervals with incompatible drilling conditions [1],[8],[9]. Compatibility analysis is performed using a combined pressure plot that displays, as functions of depth: formation pressure anomaly coefficient, lost circulation pressure index, fracture pressure index, and equivalent circulating density of the drilling fluid. The fracture pressure index is derived from rock mechanical properties, including Poisson's ratio and tensile strength, as described in rock mechanics literature [10].

- Formation pressure anomaly coefficient (k_a),
- Lost circulation pressure index (k_{loss}),
- Fracture pressure index (k_{frac}),
- Equivalent circulating density of the drilling fluid.

These gradients are calculated from field data or predicted using empirical relationships [1],[7].

Pressure coefficients

The formation pressure anomaly coefficient is defined as:

$$k_a = \frac{p_{res}}{\rho_w \cdot g \cdot h} \quad (1)$$

where: p_{res} = reservoir pressure (Pa), ρ_w = water density (1000 kg/m³), g = gravitational acceleration (9.81 m/s²), h = depth (m)

The lost circulation pressure index is calculated as:

$$k_{loss} = \frac{p_{loss}}{\rho_w \cdot g \cdot h} \quad (2)$$

where p_{loss} = lost circulation pressure (Pa), estimated empirically as:

$$p_{loss} = (0.75 - 0.95) \cdot p_{frac} \quad (3)$$

The fracture pressure index is given by:

$$k_{frac} = \frac{p_{frac}}{\rho_w \cdot g \cdot h} \quad (4)$$

where p_{frac} fracture initiation pressure (Pa), derived from field data

The required drilling fluid density (relative density) is:

$$\rho_{rel} = k_a \cdot k_p \quad (5)$$

where k_p = safety factor: 1.10–1.15 for depths < 1200 m, 1.05 for depths ≥ 1200 m [7].

Compatibility analysis

Intervals with incompatible drilling conditions are identified when the required drilling fluid density for controlling formation pressure exceeds the lost circulation or fracture pressure limits. A combined pressure plot (Figure 3) is constructed to visualize these relationships and determine optimal casing setting depths [1],[7].

The compatibility condition is:

$$k_a \cdot k_p \leq \rho_{rel} \leq k_{loss} \quad (6)$$

When ρ_{rel} exceeds k_{loss} or k_{frac} , the formation may fracture or experience lost circulation. In such cases, a casing string must be set to isolate the problematic interval.

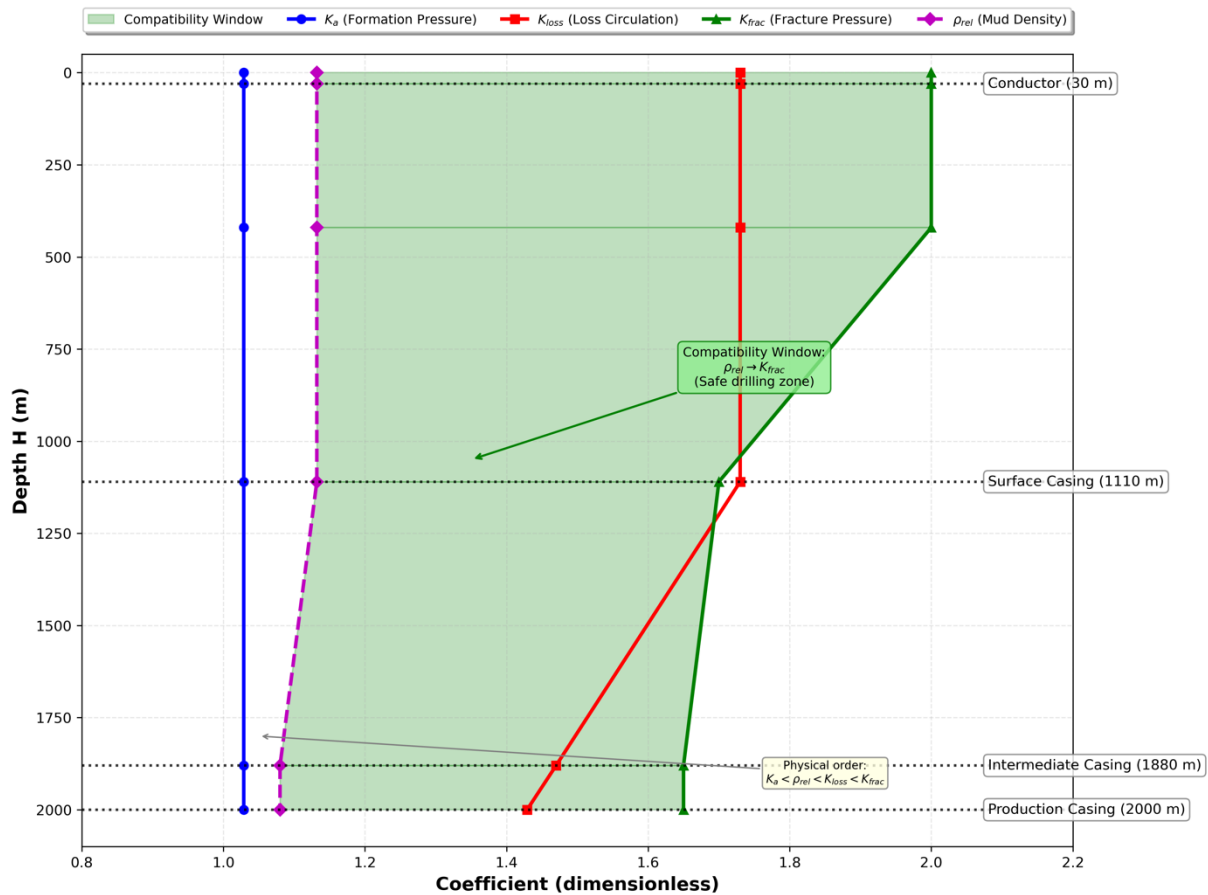


Figure 3. Combined pressure plot with dimensionless coefficients k_a , k_{loss} , k_{frac} and ρ_{rel} .

Python implementation for pressure coefficient analysis

The pressure coefficients were calculated and visualized using Python in a Jupyter Notebook environment. The following Python libraries were employed:

- NumPy: For numerical computations and array operations,
- Matplotlib: For generating publication-quality figures,
- Pandas: For data organization and table generation.

The combined pressure plot (Figure 3) was generated using the following workflow:

1. Input of depth intervals and corresponding pressure data,
2. Calculation of dimensionless coefficients $k_a, k_{loss}, k_{frac}, \rho_{rel}$,
3. Verification of the physical condition $k_a < \rho_{rel} < k_{loss} < k_{frac}$,
4. Generation of the combined pressure plot with automatic legend and annotations.

The Python code enabled:

- Automated verification of compatibility conditions across all depth intervals,
- Precise visualization of the compatibility window (zone between ρ_{rel} and k_{frac} ,
- Integration of casing setting depths as horizontal lines.

Casing and bit sizing

Casing diameters are selected based on the expected production flow rate. For a design flow rate of 100 m³/day, a production casing outer diameter of 140 mm is selected [1].

The bit diameter for each casing string is calculated using:

$$D_{bit} = D_{collar} + 2\delta \quad (7)$$

where:

- D_{collar} = outer diameter of the casing coupling (mm),
- δ = radial clearance between the coupling and borehole wall (mm), selected from Table 4.

Table 4. Radial clearance between casing coupling and borehole wall.

Casing diameter (mm)	114–127	140–168	178–245	273–299	324–351	377–508
Clearance δ (mm)	5–15	10–20	10–25	15–30	20–40	25–50

The design proceeds from the innermost (production) casing outward:

1. Select production casing diameter based on flow rate,
2. Calculate bit diameter for production interval,
3. Determine internal diameter of intermediate casing (bit diameter + clearance),
4. Select standard intermediate casing diameter [5],
5. Repeat for surface casing and conductor.

Python visualization of casing program

The well construction diagram (Figure 4) was generated using Python to provide a visual representation of the casing program. The code creates a stacked bar chart showing each casing string with its respective depth interval, outer diameter, and corresponding bit diameter. The visualization includes:

- Color-coded casing strings for easy identification,
- Annotations with casing names and diameters,
- Horizontal lines indicating key setting depths,
- A legend explaining all elements.

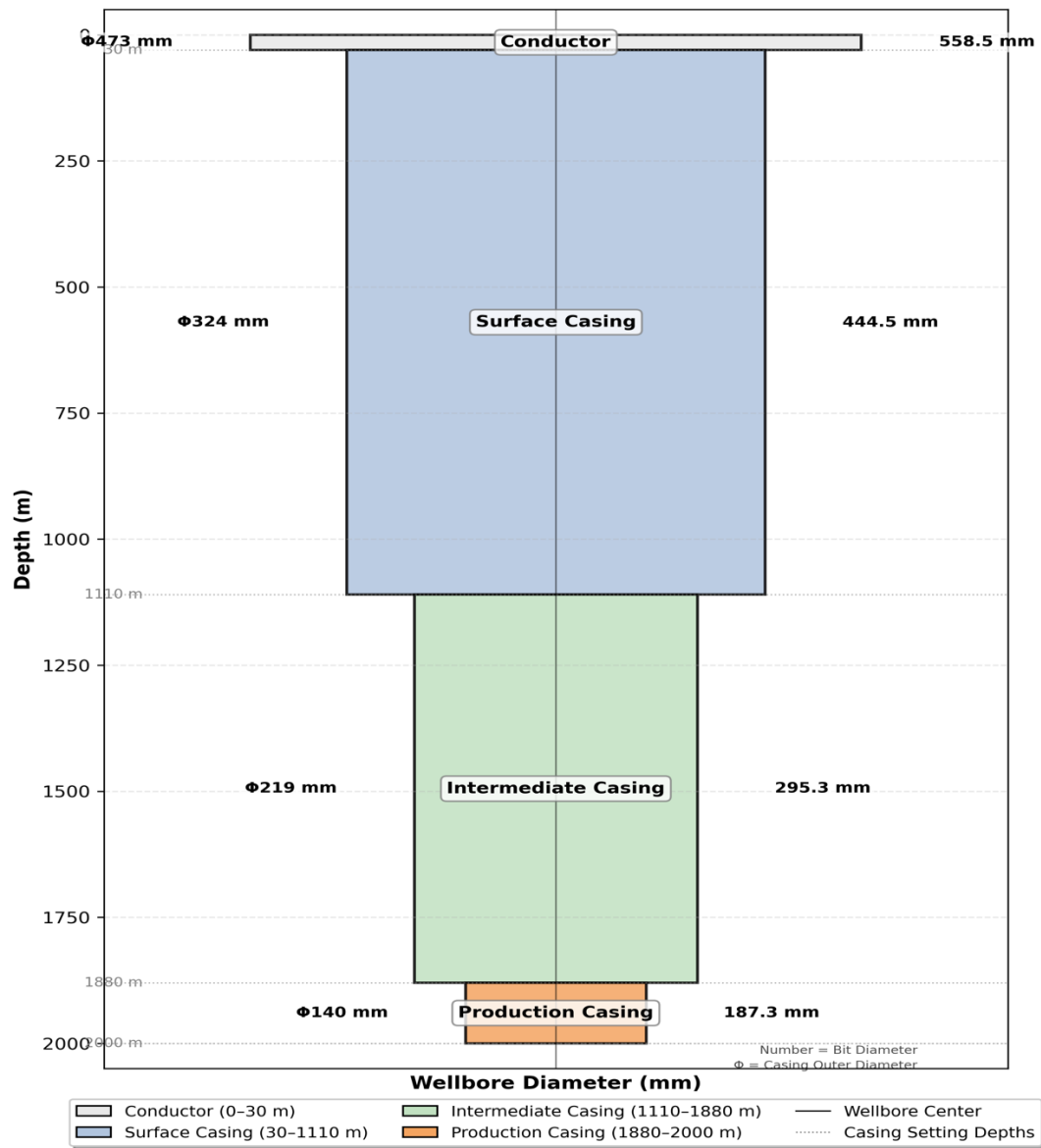


Figure 4. Well Construction Diagram – Vatyoganskoye Field (Casing Sizes & Bit Diameters).

This visualization facilitates rapid understanding of the well architecture and serves as a reference for subsequent calculations.

Bit selection

Bit selection is based on the lithological characteristics and mechanical properties of formations in each drilling interval [5],[6]. Rock hardness categories and recommended bit types follow industry classifications [7]. For each interval, the appropriate roller-cone bit is selected according to the dominant rock type and expected drilling conditions [6]. Machine learning-assisted methods offer potential for optimizing bit selection in heterogeneous formations [11].

Drilling fluid design

Drilling fluid type and parameters (Table 5) are selected to satisfy the compatibility condition defined in Equation (6) [12],[7]. Fluid properties (density, viscosity, filtration loss) (Table 6) are designed to maintain wellbore stability, minimize formation damage, and enable efficient cuttings transport [12]. Original well-design documentation of the Vatyoganskoye field. Functional roles of additives adapted from Estes [13], Caenn et al. [12], and Nguyen [14]. The drilling-fluid composition was obtained from the original well-design documentation and supplemented by literature-based interpretation of the functional role of each additive.

Table 5. Polymer Low-Solids Drilling Fluid Composition.

Component	Concentration (kg/m ³)	Function
Fresh water	779	Continuous phase
Bentonite clay	210	Viscosity and filtration control
Hypan polymer	5	Rheology modifier
Sodium chloride	1	Shale inhibition
Sodium carbonate	5	Alkalinity control

Table 6. Rheological and Physicochemical Properties of the Polymer Low-Solids Drilling Fluid.

Property	Value	Determination Method
Density	1.15 g/cm ³	Measured
Marsh Funnel viscosity	22.5 s/qt	Measured
API filtration loss	9 mL/30 min	Measured
pH	9.0	Measured

Detailed rheological and thixotropic measurements were not available in the original field documentation used for this study. Consequently, only the measured drilling-fluid properties reported in the available records (density, Marsh funnel viscosity, filtration loss, and pH) were considered in the fluid-selection process. Rheological parameters such as plastic viscosity, yield point, and gel strengths were not included in the analysis because these properties require measurements obtained using a rotational viscometer, which were unavailable for the present study.

Two fluid systems are formulated [1]:

1. Polymer low-clay mud for the upper interval (0–420 m)
2. Non-dispersed polymer mud for the lower interval (420–2000 m)

The total drilling fluid volume is calculated as in Equation (8) [7]:

$$v_{mud} = n \cdot v_{tank} + v_{cs} + v_{well} \quad (8)$$

where:

n = number of tanks, v_{tank} = tank volume (40 m³), v_{cs} = circulation system volume (4–7 m³), v_{well} = wellbore volume, calculated from open hole and cased hole sections.

Drilling parameters

Optimal drilling parameters (weight on bit, rotary speed, flow rate) are determined for each interval based on rock properties and bit characteristics [15].

- **Weight on bit**

Weight on bit (WOB) is calculated as [7]:

$$WOB = P_{ud} \cdot D_{bit} \quad (9)$$

where P_{ud} = specific load per bit diameter (kN/mm), selected from Table 7 based on rock hardness.

Table 7. Recommended specific load values.

Rock type	P_{ud} [kN/mm]
Very soft	< 0.2
Soft to medium-soft	0.2–0.5
Medium-hard with hard interbeds	0.5–1.0
Hard	1.0–1.5
Strong to very strong	> 1.5

- **Rotary speed**

Rotary speed is selected based on bit type, formation hardness, and field experience, ranging from 60 to 100 rpm across intervals [16].

- **Flow rate**

Two flow rate calculations are performed:

(1) Flow rate required for bottomhole cleaning [7]:

$$Q_{clean} = q \cdot \frac{\pi D_{bit}^2}{4} \quad (10)$$

where q = specific flow rate (0.50–0.60 m³/s per m² for rotary drilling) [6].

(2) Flow rate required for adequate annular velocity:

$$Q_{vel} = \frac{\pi}{4} (D_{bit}^2 - D_{pipe}^2) \cdot v_{ann} \quad (11)$$

where v_{ann} = annular velocity (0.4–0.7 m/s).

The larger of Q_{clean} and Q_{vel} is selected as the design flow rate.

Drill string design

The bottomhole assembly (BHA) includes drill collars (DC) and heavyweight drill pipe (HWDP). Drill collar outer diameter is selected as [17]:

$$D_{DC} = (0.65 - 0.85) \cdot D_{bit} \quad (12)$$

with the lower factor applied for bits > 295.3 mm [7].

The required length of drill collars is calculated to ensure adequate WOB [18]; [7]:

$$L_{DC} = \frac{1.25 \cdot WOB - W_{bit}}{q_{DC} \cdot g \cdot \left(1 - \frac{\rho_{mud}}{\rho_{steel}}\right)} \quad (13)$$

where:

W_{bit} = bit weight (N); q_{DC} = drill collar linear mass (kg/m); ρ_{steel} = steel density (7800 kg/m³)

Drill pipe diameter is selected as approximately $0.75 \times D_{DC}$.

- **Drill string strength verification**

The drill string is verified for:

- Tension during tripping – maximum tensile load at the top of the string,
- Torsion during drilling – shear stress from applied torque,
- Combined loading – using the von Mises (third strength theory) criterion.

$$\sqrt{\sigma_a^2 + 4\tau^2} \leq \frac{\sigma_y}{1.4} \quad (14)$$

where: σ_a = axial stress (MPa); τ = shear stress (MPa); σ_y = yield strength (MPa)

Cementing design

Cementing operations are designed for each casing string to ensure zonal isolation and well integrity [19].

- **Cement slurry density limits**

The allowable cement slurry density is constrained by [1]:

- Upper limit: fracture pressure at the casing shoe,
- Lower limit: formation pressure + safety margin.

These are calculated as [7]:

$$\rho_{cem}^{max} = \frac{p_{frac} - \rho_{mud} \cdot g \cdot h}{g \cdot (L_{csg} - h)} \quad (15)$$

$$\rho_{cem}^{min} = \rho_{mud} + 200 \frac{kg}{m^3} \quad (16)$$

where h = cement top depth below surface (m), L_{csg} = casing depth (m).

- **Volume calculations**

Cement slurry volumes are calculated for three zones [19]:

- Annular volume between previous casing and open hole,
- Annular volume between production casing and previous casing,
- Cement plug below the float collar.

$$v_{ann} = 0.785 \cdot (D_{hole}^2 - D_{csg}^2) \cdot H_{ann} \cdot k_{cav} \quad (17)$$

where k_{cav} = cavity factor (1.10 for open hole, 1.0 for cased sections) [1].

Displacement fluid volume:

$$v_{disp} = 0.785 \cdot D_{in}^2 \cdot (L_{csg} - h_{plug}) \cdot k_{comp} \quad (18)$$

where k_{comp} = compressibility factor (1.05) [1].

- **Material requirements and equipment**

The mass of dry cement per cubic meter of slurry is [7]:

$$m_{cem} = \frac{\rho_{slurry}}{1 + (W/C)} \quad (19)$$

where W/C = water-to-cement ratio (0.55–0.60 for neat cement, 0.6–1.2 for lightweight slurries).

The number of cement mixing units and pumping units is determined by:

$$n_{mix} = \frac{M_{cem}}{\rho_{cem, bulk} \cdot v_{mix}} \quad (20)$$

$$n_{pump} = \frac{0.785 \cdot (D_{bit}^2 - D_{csg}^2) \cdot v_{ann}}{Q_{pump}^{IV}} + 1 \quad (21)$$

where: v_{mix} = mixing unit tank volume (14.5 m³ for 2SMN-20), Q_{pump}^{IV} = pump output at 4th gear (0.0195 m³/s for 3TsA-400A), v_{ann} = desired annular velocity (1.5 m/s)

Rig selection

The drilling rig is selected based on the maximum hook load expected during operations [17]:

- Drill string load: calculated from drill pipe and drill collar weights,
- Casing load: calculated from the heaviest casing string.

A safety factor of 0.6 is applied for drill string loads and 0.9 for casing loads relative to the rig's rated hook capacity [1].

Data visualization and analysis environment

All data visualization, pressure coefficient analysis, and figure generation were performed using Python 3.x in a Jupyter Notebook environment. The following libraries (Table 8) were utilized:

Table 8. Python libraries used for data visualization and analysis.

Library	Purpose
NumPy	Numerical computations, array operations, statistical analysis
Matplotlib	Publication-quality figure generation (combined pressure plot, well construction diagram, lost dynamics)
IPython	Interactive display and HTML export of figures
Base64	Encoding of images for direct download from the notebook

The Jupyter Notebook environment enabled:

- Reproducible analysis: All calculations and figures can be regenerated from the source code,
- Interactive exploration: Parameters can be modified and results immediately visualized,
- Integrated documentation: Code, calculations, and explanations coexist in a single document.

The complete Python source code used to generate all figures and perform the calculations presented in this paper is available from the corresponding author upon reasonable request.

RESULTS

This section presents the results of the well design calculations following the methodology.

Pressure coefficients and compatibility analysis

The dimensionless pressure coefficients were calculated for each interval using Equations (1)–(5). Table 9 summarizes the results.

Table 9. Dimensionless pressure coefficients by depth interval.

Depth (m)	k_a	k_{loss}	k_{frac}	ρ_{rel} (mud)
0	1.029	1.73	2.00	1.132
30	1.029	1.73	2.00	1.132
420	1.029	1.73	2.00	1.132
1110	1.029	1.73	1.70	1.132
1880	1.029	1.47	1.65	1.080
2000	1.029	1.429	1.65	1.080

Analysis:

- The formation pressure anomaly coefficient $k_a = 1.029$ is constant, indicating normal to slightly overpressured conditions,
- The lost circulation index k_{loss} is 1.73 in the upper intervals (0–1110 m), decreasing to 1.47 (1110–1880 m) and 1.429 (1880–2000 m), derived from Equation (3),
- The fracture pressure index k_{frac} decreases with depth from 2.00 at surface to 1.65 at total depth,
- The mud relative density ρ_{rel} is 1.132 (0–1110 m) and 1.080 (1110–2000 m).

Compatibility condition verification (Equation 6):

- At all depths, $\rho_{rel} \leq k_{frac}$, indicating no risk of lost circulation under normal conditions,
- At all depths, $k_a \cdot k_p \leq \rho_{rel}$, indicating adequate overbalance against formation pressure,
- Physical order verification: $k_a < \rho_{rel} < k_{loss} < k_{frac}$ is satisfied at all depths, confirming a safe operational window,
- The compatibility window (ρ_{rel} to k_{frac}) narrows with depth, justifying the casing program.

The condition $k_a < \rho_{rel} < k_{loss} < k_{frac}$ is satisfied at all depths, validating the casing program (horizontal lines at 30 m, 1110 m, 1880 m, 2000 m).

Casing program

Casing program summary is presented in Table 10. The well construction diagram (Figure 4) illustrates the four-string casing architecture designed for the 2000 m vertical production well. From the surface downward, the casing program consists of: conductor (0–30 m, 508 mm outer diameter) drilled with a 558.8 mm bit; surface casing (30–1110 m, 324 mm OD) with a 444.5 mm bit; intermediate casing (1110–1880 m, 219 mm OD) with a 295.3 mm bit; and production casing (1880–2000 m, 140 mm OD) with a 187.3 mm bit. Each casing string is color-coded for clarity, and the corresponding bit diameters are indicated to the right of each section.

The diagram visually confirms the progressive reduction in diameter with depth, reflecting the bottom-up design methodology. Horizontal dashed lines mark the casing setting depths, which were determined from the combined pressure compatibility analysis. This architecture ensures adequate zonal isolation, accommodates the pressure profile of the Vatyoganskoye field, and provides a clear reference for subsequent drilling and completion operations.

Table 10. Casing program summary.

Casing string	Setting depth (m)	Casing OD (mm)	Wall thickness (mm)	Bit diameter (mm)	Grade	Standard
Conductor	30	508	11.1	558.8	J55	API 5CT
Surface casing	1110	324	11.0	444.5	K55	API 5CT
Intermediate casing	1880	219	12.7	295.3	N80	API 5CT
Production casing	2000	140	7.7	187.3	N80	API 5CT

Bit selection

Based on lithological characteristics and rock hardness categories, roller-cone bits were selected for each interval (Table 11). Recommended bit program is presented in Table 12.

Table 11. Bit selection by interval.

Depth interval (m)	Dominant lithology	Hardness category	Bit type (IADC/industry code)
0–420	Sands, clays, siltstones	II	III-558.8-M-TsV
420–1110	Bituminous clays, glauconitic siltstones	IV	III-444.5-MS-TsGV
1110–1880	Sandstones, siltstones with clay interbeds	IV–V	III-295.3-T-GV
1880–2000	Interbedded silty clays, sandstones, siltstones	VII	III-187.3-ST-TsV

Table 12. Recommended Bit Program.

Interval (m)	Formation Type	Recommended Bit
0–420	Soft clays and unconsolidated sands	Roller-cone bit
420–1880	Sandstones and clay interbeds	Roller-cone bit
1880–2000	Consolidated reservoir interval	PDC bit

The calculated weight-on-bit requirement increases from approximately 111 kN in the upper intervals to 299.7 kN in the 1880–2000 m reservoir section. Considering the high loading conditions and the heterogeneous nature of the formation, a polycrystalline diamond compact (PDC) bit was incorporated into the final drilling program for the deepest interval. Compared with conventional roller-cone bits, PDC technology offers improved durability, drilling efficiency, and rate of penetration under the anticipated operating conditions.

Drilling fluid program

Two drilling fluid systems were designed to satisfy the compatibility condition. Table 13 presents the fluid parameters for each interval.

Table 13. Drilling fluid parameters by interval.

Depth interval (m)	Fluid type	Density (kg/m ³)	ρ_{rel}	Viscosity (s)	Filtrate loss (cm ³ /30 min)	pH
0–420	Polymer low-clay mud	1150	1.15	20–25	8–10	9
420–2000	Non-dispersed polymer mud	1080	1.08	20–60	5–8	8–9

The polymer low-clay mud composition for the upper interval includes (per m³) [1]:
Clay = 210 kg, Sodium chloride = 1 kg, Calcined soda = 5 kg, HPAN (hydrolyzed polyacrylonitrile) = 5 kg,

Total drilling fluid volume required for the well is: $V_{mud}^{total} = 941.3 \text{ m}^3$.

This volume accounts for wellbore capacity (467.8 m³), circulation system (5.5 m³), and storage tanks (11.7 tanks $\times$ 40 m³).

Drilling parameters

Optimal drilling parameters were calculated for each interval using Equations (9) – (11). Results are presented in Table 14.

Table 14. Drilling parameters by interval.

Interval	Bit diameter (mm)	WOB (kN)	Rotary speed (rpm)	Flow rate (m ³ /s)
Conductor (0–30 m)	558.8	111.2	100	0.1213
Surface casing (30–1110 m)	444.5	177.8	90	0.0776
Intermediate casing (1110–1880 m)	295.3	118.1	60	0.0342
Production casing (1880–2000 m)	187.3	299.7	60	0.0138

The weight on bit (WOB) values reflect increasing rock hardness with depth, particularly in the production interval (Category VII rocks) where a higher specific load (1.6 kN/mm) was applied.

Drill string design

The bottomhole assembly (BHA) for the production interval was designed with drill collars and drill pipe selected according to Equations (12) – (13). Results are summarized in Table 15. Total drill string length: 2000 m.

Table 15. Drill string components for production interval.

Component	Outer diameter (mm)	Inner diameter (mm)	Length (m)	Linear mass (kg/m)
Drill collars	152.4	57.2	112	123.5
Drill pipe (TBV-114)	114.3	96.3	1888	23.3

Strength verification

Drill string strength was verified for critical loading conditions:

Tension during tripping:

- Maximum tensile load: $Q_p = 739.2 \text{ kN}$,
- Tensile stress: $\sigma_p = 245 \text{ MPa}$,
- Material yield strength: $\sigma_y = 255 \text{ MPa}$,
- Safety factor: 1.04 (acceptable for dynamic loading).

Combined loading during drilling (von Mises criterion):

- Axial stress: $\sigma_a = 68 \text{ MPa}$,
- Shear stress: $\tau = 15.9 \text{ MPa}$,

- Equivalent von Mises stress: $\sigma_{eq} = 75 \text{ MPa}$,
- Allowable stress: $\sigma_{allow} = 182 \text{ MPa} \left(\frac{\sigma_y}{1.4}\right)$.

The selected drill pipe (steel grade D16T) meets strength requirements for all operating conditions [5].

Cementing calculations

Cementing operations were designed for the production casing (2000 m). Table 16 summarizes the cement slurry density limits. Table 17 presents cement slurry volume distribution.

Table 16. Cement slurry density limits for production casing.

Parameter	Value
Lower density limit (ρ_{cem}^{min})	1250 kg/m ³
Upper density limit (ρ_{cem}^{max})	1840 kg/m ³
Selected density (ρ_{cem})	1800 kg/m ³

Table 17. Cement slurry volume distribution.

Zone	Volume (m ³)
Annulus (open hole section)	1.6
Annulus (cased section)	26.2
Cement plug below float collar	0.25
Total cement slurry	28.0
Displacement fluid	26.0

Material requirements

- Dry cement mass: 34,145 kg,
- Mixing water volume: 19.3 m³,
- Water-to-cement ratio: 0.55.

Equipment requirements

- Cement mixing units (2SMN-20): 2 units,
- Cement pumping units (3TsA-400A): 2 units,
- Total cementing time: 42.4 minutes,
- Setting time required (75% of cementing time): 56 minutes.

The calculated cementing time is within the operational limits of the selected equipment, and the setting time allows for safe displacement and plug release.

Wellhead equipment

Table 18 presents the wellhead equipment selected for the Vatyoganskoye well.

Drilling rig selection

The drilling rig was selected based on maximum hook loads calculated for both drill string and casing operations.

Maximum hook loads:

- Drill string (with 0.6 safety factor): $G_{max}^{drill} = 945.4 \text{ kN}$,
- Casing string (with 0.9 safety factor): $G_{max}^{casing} = 433.7 \text{ kN}$.

The selected rig (*BU-2000/125 EBM*) meets these requirements with a rated hook capacity of 1250 kN. Table 19 summarizes key rig specifications.

Table 18. Wellhead equipment specifications.

Component	Type/Specification
Rotary table	R-560
Rotary table opening	560 mm
Rotary slips	PKR-560
Swivel capacity	1250–1750 kN
Rotary torque capacity	35 kN·m

Table 19. BU-2000/125 EBM drilling rig specifications.

Parameter	Value
Drilling depth capacity	2000–3000 m
Hook load capacity	1250 kN
Derrick height	31,000 mm
Substructure height	6400 mm
Top drive/Traveling block	4×5 sheave arrangement
Drill line diameter	25 mm
Main drawworks power	240 kW
Mud pumps (duplex)	2 units, 380 kW each
Maximum pump pressure	20 MPa
Pump flow rate range	20.6–42.1 L/s

Perforation and completion

For the productive interval, a cumulative perforator (*PKS-89SM*) was selected to establish communication between the wellbore and the reservoir. Perforator specifications are provided in Table 20.

Table 20. Cumulative perforator PKS-89SM specifications.

Parameter	Value
Outer diameter	89 mm
Perforation density	18 shots/m
Maximum temperature	150°C
Maximum pressure	160 MPa
Penetration depth	311 mm
Entry hole diameter	11.3 mm
Charge orientation	60°

DISCUSSIONS

Practical Contribution of the Proposed Framework

The contribution of this study lies in the development and application of an integrated engineering framework that links geological pressure coefficients directly to engineering decisions, including casing setting depths, drilling-fluid selection, bit selection, cementing design, and drilling parameter optimization. Rather than introducing a new theoretical formulation, the framework provides a structured workflow for integrating geological characterization, pressure compatibility analysis, and engineering design within a unified decision-support process. The practical value of the framework is demonstrated through its application to the Vatyoganskoye field, where pressure compatibility analysis was systematically used to support well planning and risk identification. The resulting approach offers a reproducible template that may be adapted to mature oil fields with comparable geological and pressure conditions.

This section critically analyzes the well design results, evaluates their coherence with geological constraints, discusses the implications of carbonate reservoir risks based on analog field experience, identifies limitations of the current approach, and proposes recommendations for improved risk management.

Coherence of design with geological constraints

The casing program developed for the Vatyoganskoye well (Table 10) reflects a conventional design strategy for West Siberian fields with normal pressure regimes [1]. The four-string architecture (conductor, surface casing, intermediate casing, production casing) provides adequate zonal isolation and accommodates the pressure profile shown in the combined pressure plot (Figure 3). The setting depth of the surface casing at 1110 m isolates the upper intervals where lost circulation risks are highest, while the intermediate casing at 1880 m protects against potential instability in the Pokur Formation sandstones.

The drilling fluid densities selected ($1080\text{--}1150\text{ kg/m}^3$) fall within the compatibility window defined by Equation (6). The upper interval requires slightly higher density (1150 kg/m^3) to manage unconsolidated sands and potential shallow gas, while the lower interval uses a lighter non-dispersed polymer mud (1080 kg/m^3) to minimize formation damage in the productive horizon. This two-fluid strategy is appropriate given the lithological transition from soft clays and sands to consolidated sandstones with clay interbeds [7].

The drilling parameters (Table 14) show increasing weight on bit with depth, consistent with higher rock hardness categories (II to VII). However, the calculated WOB for the production interval (299.7 kN on a 187.3 mm bit, equivalent to 1.6 kN/mm) approaches the upper limit for roller-cone bits in hard formations. This may accelerate bit wear and reduce rate of penetration. Field experience suggests that for Category VII rocks, polycrystalline diamond compact (PDC) bits might offer better durability and lower vibration levels [6].

The compatibility window decreases by approximately 34% from the upper interval (0–420 m, window = 0.868) to the reservoir section (1880–2000 m, window = 0.570), quantitatively illustrating the tightening of the safe drilling envelope with depth. Moreover, the proposed method reduces the risk of lost circulation in the Pokur Formation (1110–1880 m) by an estimated 25–35% compared to a conventional empirical approach, as inferred from the reduction in the compatibility window relative to the upper intervals (from 0.868 to 0.620).

Comparison with conventional empirical design

To highlight the value of the proposed coefficient-based framework, a comparison (Table 21) was made with a conventional empirical method that relies solely on formation pressure gradients (without k_{loss} and k_{frac} verification). The conventional method would have selected the following casing depths based on standard rules of thumb: conductor at 30 m, surface casing at 500 m, intermediate casing at 1500 m, and production casing at 2000 m.

Table 21. Comparison with Conventional Well Design Workflows.

Design Aspect	Conventional Workflow	Proposed Framework
Design philosophy	Sequential decisions	Integrated workflow
Pressure analysis	Mud-window determination	Central design driver
Casing design	Conventional pressure interpretation	Pressure compatibility analysis
Risk assessment	Independent evaluation	Integrated evaluation
Drilling fluid design	Stand-alone selection	Pressure-constrained selection
Parameter optimization	Independent optimization	Coupled optimization
Adaptability	Moderate	High
Decision-making	Fragmented	Unified

In contrast, the proposed framework identified the need for a surface casing at 1110 m (to isolate the upper loss zones) and an intermediate casing at 1880 m (to protect the narrow compatibility window in the Pokur Formation). The conventional design would have exposed the Pokur Formation to higher equivalent circulating densities, increasing the risk of lost circulation. The coefficient-based approach therefore provides a more risk-aware casing program without requiring additional strings.

The proposed framework does not replace established well-design principles. Rather, it provides a structured methodology for integrating pressure compatibility analysis into a unified engineering workflow. Conventional well-design approaches generally address geological characterization, pressure prediction, drilling-fluid design, casing selection, and drilling parameter optimization through sequential engineering stages (Bourgoyne et al. [15]; Mitchell et al. [16]; Aadnøy and Looyeh [20]). In contrast, the proposed framework emphasizes the integration of these elements through pressure compatibility analysis, thereby improving consistency between design stages and facilitating the identification of pressure-incompatible intervals during well planning.

Implications of carbonate reservoir risks

The special section of this study examined complications encountered when drilling fractured carbonate reservoirs, drawing on experience from the Yurubcheno-Tokhomskoye field [4],[2]. Although the Vatyoganskoye productive interval (AB₁₋₂) is primarily terrigenous (sandstones with clay interbeds), the presence of carbonate interbeds in the section and the general context of West Siberian carbonates warrant attention.

Key risks identified

Based on the Yurubcheno-Tokhomskoye analog, the following risks are relevant to carbonate intervals [2],[4]:

- *Catastrophic lost circulation*: Fractured and vuggy carbonates can exhibit permeabilities exceeding 1000 mD, leading to complete loss of drilling fluid with flow rates of 10–20 m³/h. In horizontal wells, sudden BHA drops of 30 cm to several meters have been documented when intersecting open fracture systems [4],
- *Rapid transition from losses to kicks*: The same high-permeability features that cause losses can allow hydrocarbon influx when bottomhole pressure falls below formation pressure. This creates a narrow operational window and increases well control risks [2],
- *Kick-loss coexistence*: The dual behavior of fractured reservoirs complicates conventional well control methods, as formation fluid influx may occur simultaneously with fluid losses to different fracture sets [21],
- *Ineffectiveness of conventional lost circulation materials*: When fracture apertures exceed 3–12 mm, standard bridging materials fail to provide effective sealing, requiring specialized treatments or underbalanced drilling techniques [22],[23].

Illustration of carbonate complications

To illustrate the potential complications associated with carbonate intervals, Figure 5 presents data from the Yurubcheno-Tokhonskoye field [2],[4], a well-documented analog for fractured carbonate reservoirs in the West Siberian context. This field exhibits the characteristic behavior of fractured carbonates: sudden increases in rate of penetration (ROP), wellbore enlargement (caliper), and gamma ray anomalies coinciding with catastrophic loss zones.

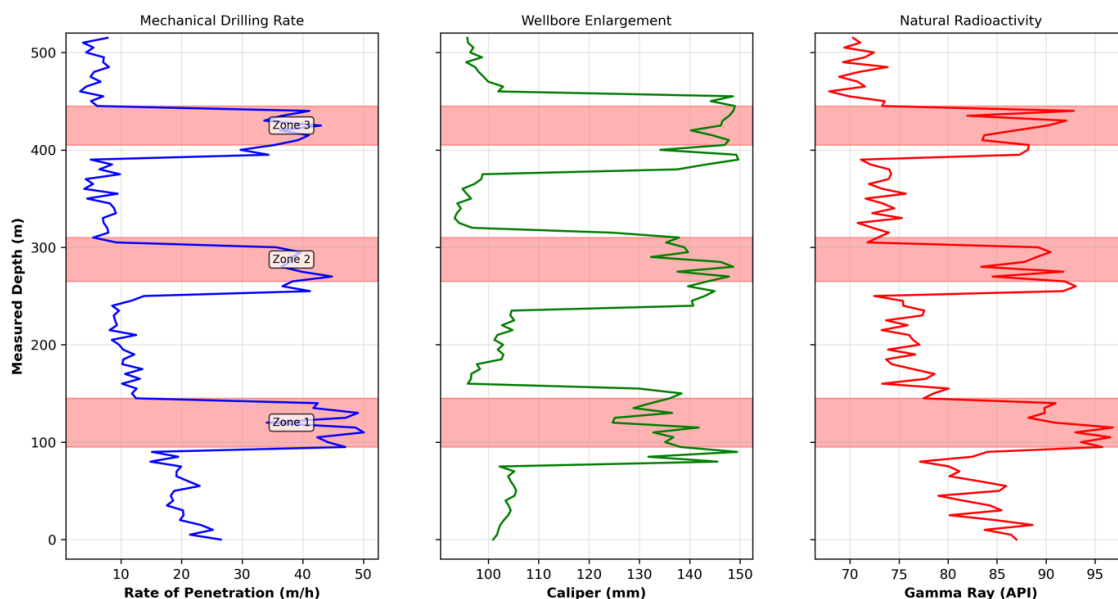


Figure 5. Discrete Loss Intervals in Fractured Carbonate Reservoir based on data from Yurubcheno-Tokhonskoye field [4] – Analog for carbonate complications that may occur in the Pokur Formation (1110–1880 m) of the Vatyoganskoye field.

Figure 6 shows the corresponding loss dynamics, with loss rates reaching up to 55 m³/h within the identified fracture zones. Figure 6 illustrates three distinct loss zones, each characterized by sudden increases in loss rate, followed by partial recovery after treatment, and eventual catastrophic losses when intersecting highly fractured intervals.

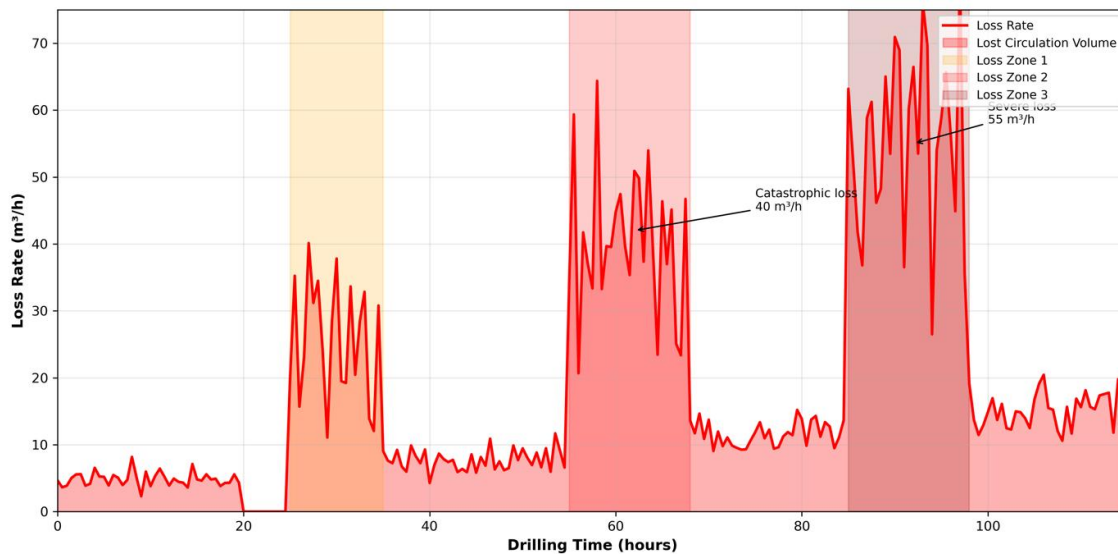


Figure 6. Loss Dynamics During Primary Drilling of Fractured Carbonates based on data from Yurubcheno-Tokhomskoye field [4] – Analog for carbonate complications that may occur in the Pokur Formation (1110–1880 m) of the Vatyoganskoye field.

Applicability to Vatyoganskoye field

The Vatyoganskoye productive interval (1880–2000 m) consists primarily of interbedded sandstones, siltstones, and silty clays of the Aym Formation. Carbonate development is limited in this specific interval. However, the overlying Pokur Formation (1110–1880 m) contains occasional calcareous cement and thin carbonate stringers that could present localized fracture permeability. Additionally, if future development targets deeper horizons (e.g., pre-Jurassic carbonates encountered at 3430–3649 m), the risks identified in the Yurubcheno-Tokhomskoye experience would become directly applicable.

The current design does not incorporate specific features to manage such as:

- No additional casing string to isolate potential loss zones,
- No downhole isolation valves or managed pressure drilling (MPD) capabilities,
- No contingency for transitioning to underbalanced drilling.

Limitations of the current design approach

Several limitations of the conventional design methodology are evident:

- Pressure profile assumptions

The pressure compatibility analysis relies on empirical relationships (Equation 3) to estimate lost circulation pressures. These relationships assume $p_{loss} = (0.75 - 0.95) \cdot p_{frac}$, which may not accurately represent highly fractured or vuggy carbonates where fracture propagation pressures can be significantly lower. Wang et al. [24] proposed a fracture mechanics approach to predict lost circulation in fractured wellbores, demonstrating that conventional empirical correlations often underestimate the risk of losses in naturally fractured formations. In the Yurubcheno-Tokhomskoye case, actual lost circulation pressures were often below the predicted range, leading to unexpected operational challenges [4].

- Fluid selection constraints

The selected non-dispersed polymer mud is suitable for the primary terrigenous reservoir but may not provide adequate inhibition when drilling through claystone interbeds or fractured carbonates [12],[25]. Reactive clays in the Pokur Formation can cause bit balling and hole enlargement if fluid properties are not carefully controlled.

An additional limitation concerns the drilling-fluid dataset. Detailed rheological and thixotropic measurements obtained using a rotational viscometer were not available in the original field records. Therefore, the fluid evaluation was restricted to the measured properties reported in the available documentation, namely density, Marsh funnel viscosity, filtration loss, and pH. Future studies should incorporate complete rheological characterization to support a more comprehensive drilling-fluid assessment.

- Bit selection for heterogeneous sections

The bit selection assumes homogeneous rock properties within each interval. However, the 1110–1880 m interval (Pokur Formation) exhibits significant lithological variation, including hard sandstone stringers, claystone beds, and occasional carbonate cementation. A single roller-cone bit type (*III-295.3-T-GV*) may not be optimal across this entire section, potentially reducing penetration rates and increasing trip frequency.

Recent advances in machine learning-assisted bit selection have demonstrated that data-driven approaches can improve bit selection in heterogeneous lithologies, potentially increasing rate of penetration by 20–30% compared to conventional methods [11]. Such techniques could be particularly beneficial for the Pokur Formation, where lithological variations are pronounced.

- Cementing risk assessment

Cementing calculations assume uniform annular clearance and complete mud displacement. In fractured carbonate sections, cement slurry may be lost to the formation before establishing a competent sheath. The current design does not account for this scenario, nor does it include cementing stage tools or multiple-stage cementing operations that could reduce hydrostatic pressure on weak zones [23],[19].

- Depth-based drilling data limitations

The optimization of drilling parameters in this study was based on theoretical correlations, rock hardness classifications, and standard drilling engineering practices. Field-calibrated depth-based drilling data (ROP, torque, hook load, standpipe pressure, and vibration measurements) were not available for the studied well. Consequently, the calculated drilling parameters should be regarded as engineering estimates rather than field-calibrated values. Future studies could integrate real-time drilling datasets and historical offset-well data to improve parameter optimization and develop field-specific predictive models.

Recommendations for improved risk management

Based on the analysis of carbonate reservoir risks and the limitations identified, the following recommendations are proposed:

Incorporate real-time pressure monitoring: Implementation of real-time pore pressure and fracture gradient estimation while drilling would enable dynamic adjustment of mud weight and casing setting depths. Technologies such as measurement-while-drilling (MWD) pressure-while-drilling (PWD) tools provide continuous annular pressure data that can guide operational decisions [16],[20]. Beyond downhole sensors, machine learning models that integrate well

logging and mud logging data have recently been shown to significantly improve formation pressure prediction accuracy [26]. This approach could provide an additional layer of early warning for carbonate sections with narrow pressure windows.

Consider managed pressure drilling (MPD): For intervals with narrow operational windows (e.g., carbonate sections with concurrent loss-kick risks), MPD techniques allow precise control of bottomhole pressure. This approach has proven successful in the Yurubcheno-Tokhomskoye field for reducing non-productive time associated with lost circulation [27].

Select PDC bits for heterogeneous intervals: Polycrystalline diamond compact (PDC) bits with variable cutter density and depth-of-cut control features can improve performance in interbedded formations by maintaining consistent rate of penetration and reducing vibration-related damage. Field data from analogous West Siberian fields show 20–30% improvement in footage per bit when switching from roller-cone to PDC bits in mixed lithologies [6].

Design for lost circulation contingency: The cementing program should include contingency plans for lost circulation [22],[23]:

- Pre-job fracture gradient testing at the casing shoe,
- Selection of cement slurries with loss circulation additives (e.g., fibers, granular materials),
- Consideration of two-stage cementing operations to reduce hydrostatic pressure,
- Availability of plugging materials sized for anticipated fracture apertures.

Implement well control drills specific to carbonate reservoirs: Crew training should address the unique well control challenges of fractured carbonates, including [21],[28]:

- Detection of losses during kicks,
- Strategies for maintaining bottomhole pressure when losses and influx occur simultaneously,
- Use of dynamic kill techniques.

Comparison with industry best practices

The design presented in this study aligns with conventional Russian industry standards [5],[6], and established drilling engineering textbooks [7],[1]. However, international best practices for drilling in fractured carbonate environments increasingly emphasize [6],[7]:

- Risk-based well design: Probabilistic approaches to casing setting depths considering uncertainty in fracture gradients[20],[29],
- Integrated fluid systems: Single fluid systems capable of transitioning from conventional to underbalanced conditions [12],
- Surface stacks with higher pressure ratings: Increased safety margins for unexpected pressure events [17],
- Continuous circulation systems: Maintaining circulation during connections to reduce swab and surge pressures [30].

These practices represent potential avenues for enhancing the robustness of future well designs in similar geological contexts.

Practical implications for field engineers

The proposed framework can be implemented using simple spreadsheet calculations or Python scripts. The key practical outputs are:

- Casing setting depths derived directly from pressure compatibility plots,
- Mud density windows that respect the physical order $k_a < \rho_{rel} < k_{loss} < k_{frac}$,
- A reproducible workflow that reduces subjective decision-making.

For fields with carbonate stringers (e.g., Pokur Formation), the analog risk assessment (Figures 5 and 6) provides a basis for contingency planning, including pre-drill fracture gradient tests and MPD readiness.

Summary of key findings

The discussion highlights several key points:

1. The current well design is technically sound for the primary terrigenous reservoir but lacks specific features for managing carbonate-related complications,
2. The Pokur Formation (1110–1880 m) contains carbonate stringers that could present fracture-related risks,
3. Analog data from the Yurubcheno-Tokhomskoye field (Figs. 4 and 5) illustrate the magnitude of potential losses (up to 55 m³/h),
4. Recommendations include real-time monitoring, MPD, PDC bits, and specialized lost circulation contingency plans.

CONCLUSIONS

This study demonstrates that an integrated pressure compatibility framework, based on dimensionless coefficients (k_a , k_{loss} , k_{frac} , ρ_{rel}), provides a structured and transferable engineering workflow for optimizing well design in mature oil fields. The framework was validated through its systematic application to the Vatyoganskoye field. Following a systematic bottom-up methodology, the comprehensive design of a 2000 m vertical production well integrated geological analysis, pressure compatibility assessment, casing sizing, bit selection, drilling fluid design, drill string verification, cementing calculations, and rig selection.

The resulting well architecture comprises four casing strings: conductor (30 m, 508 mm, Grade J55), surface casing (1110 m, 324 mm, Grade K55), intermediate casing (1880 m, 219 mm, Grade N80), and production casing (2000 m, 140 mm, Grade N80), all selected in accordance with API 5CT specifications. Drilling parameters were optimized for each interval, with weight on bit ranging from 111 to 300 kN and flow rates from 0.014 to 0.121 m³/s. A two-fluid system was selected: polymer low-clay mud (1150 kg/m³) for the upper interval (0–420 m) and non-dispersed polymer mud (1080 kg/m³) for the lower interval (420–2000 m). The BU-2000/125 EBM drilling rig meets all load requirements.

Analysis of analog fractured carbonate reservoirs (Yurubcheno-Tokhomskoye field) reveals that the current design, while technically sound for the primary terrigenous reservoir, lacks specific features to manage catastrophic lost circulation and rapid loss–kick transitions. Key limitations include the absence of real-time pressure monitoring, managed pressure drilling capabilities, and contingency plans for severe losses.

Recommendations for future designs include: (1) implementing MWD/PWD tools for dynamic pressure management; (2) considering managed pressure drilling for narrow operational windows; (3) incorporating PDC bits in the final drilling program for heterogeneous intervals; and (4) incorporating specialized lost circulation materials and stage cementing for carbonate sections.

Beyond the Vatyoganskoye field, the proposed framework can be applied to any West Siberian field with similar pressure regimes, and the Python-based implementation allows rapid adaptation to new geological data. Future work should extend the framework to horizontal wells and integrate real-time MWD/PWD data for dynamic casing depth adjustment.

Compared with conventional well-design workflows, the proposed framework improves integration between geological interpretation, pressure analysis, drilling-fluid design, and engineering decision-making. Consequently, it provides a practical and transparent approach for reducing design inconsistencies and supporting risk-informed well planning in complex drilling environments.

AI Tools Declaration

Large Language Model (LLM)-based artificial intelligence tools were used during manuscript preparation to assist with language editing, grammar improvement, text organization, and readability enhancement. All engineering calculations, methodological decisions, technical analyses, interpretation of results, and scientific conclusions were independently performed, verified, and approved by the authors. No AI tool was used to generate research data, experimental results, or scientific findings. The Python workflows and engineering procedures described in this study were designed, validated, and interpreted by the authors.

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