RESEARCH ARTICLE

A fishtail well design for cyclic steam injection—A case study from Yarega heavy oil field in Russia

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Abstract

Yarega heavy oil field (YHOF) is a naturally fractured heavy oil field where only recently steam-assisted gravity drainage (SAGD) technology has been introduced. SAGD employed in this field has so far resulted in early steam breakthrough leading to producer well abandonment and recurrent drilling procedures invariably increasing costs. Therefore, as opposed to SAGD, we propose the joint application of cyclic steam injection (CSS) technology with fishtail wells. The advantages of CSS are well documented. The addition of fishtail wells to this strategy assists in reducing the travel time the mobilized oil takes to arrive at a well perforation. Our results demonstrate that the synergy between these two strategies can further improve recoveries in heavy oil reservoirs. A reservoir simulation model of a sector in the YHOF is employed to understand heat/mass transfer mechanisms and for production enhancement recommendations. Different well configuration strategies were tested on this model. Results from the three-dimensional sector in the YHOF model suggest that in addition to the thermal development technologies employed in this reservoir, CSS coupled with fishtail wells provided favorable steam-oil ratios, cumulative energy-oil ratios, and enhanced cumulative oil recovery for a naturally fractured reservoir. Well abandonment issues arising from SAGD approach currently being applied can therefore be eliminated. Based on results from this research, we recommend the testing of a fishtail well development plan with CSS that includes a 10-day steam injection, 10-day soaking period, and 10-day production period. In comparison with continuous steam injection recovery (4.5% over 3 years), our simulation results showed an improved recovery of 7% over the same period with this concept. In addition to the technical advantage of this strategy, favorable steam-oil and energy-oil ratios imply that minimal economic costs are achieved and carbon footprints are lessened.

KEYWORDS
enhanced oil recovery, fishtail well, high-viscosity oil, numerical modeling
1 | INTRODUCTION

Heavy oil reservoirs are known to pose recovery challenges due to the high viscosities and densities of the hydrocarbons which make them flow slow and can sometimes be completely immobile. Common methods of recovery from these unconventional resources include chemical, gas, or thermal procedures. Chemical processes target minimizing viscous fingering commonly encountered when waterflooding is employed in heavy oil fields. Chemicals such as polymers, surfactants, and solvents are added to the water to lower interfacial tensions (IFT), control mobility, and alter wettability of rocks.\(^1\)\(^-\)\(^3\) Gas flooding for heavy oil reservoir development improves oil recovery by lowering IFT, reducing viscosity, and inducing swelling of the oil.\(^4\)\(^,\)\(^5\) Permanent storage of \(\text{CO}_2\) during gas injection also makes this technology attractive for environmental reasons.\(^6\)\(^-\)\(^10\)

Thermal techniques involve the application of steam or combustion in recovery. These methods along with hybrid methods have generally been the most widely employed due to their immense success.

The basic idea behind the application of thermal strategies is the transfer of heat from the injector to the heavy oil leading to increase in mobility by lowering the viscosity of the fluid. Forms of thermal methods which have been employed include steam-assisted gravity drainage (SAGD) where steam is injected into an upper well to lower the viscosity of the heavy oil. The now mobile oil subsequently drains into a lower well via gravity. Modifications of this procedure include the FAST-SAGD\(^11\)\(^,\)\(^12\) and the noncondensable gases SAGD\(^13\)\(^,\)\(^14\) which help to improve on certain undesired characteristics of the conventional SAGD. Cyclic steam injection (CSS) is another thermal technique which involves different cycles of injection, soaking, and production. In the first stage, steam is injected into the reservoir after which the well is shut-in and allowed to soak in the oil. After the oil viscosity is reduced, the well is produced. This method bears similarities to the huff-and-puff technique during \(\text{CO}_2\) flooding.\(^15\)\(^,\)\(^16\)

Steam flooding is the continuous injection of steam via vertical wells to reduce the viscosity of the oil. An added benefit of this technique is the formation of a condensed water and oil zone which assists in further mobilization of oil.\(^17\)\(^-\)\(^19\) In situ combustion (ISC) otherwise known as fire flooding as another thermal method entails the injection of a combustion agent which reacts with in situ hydrocarbons in an exothermic oxidation process leading to heat generation. Mobility of oil is thus improved as a result of the heat generation.\(^20\)\(^,\)\(^21\) Additionally, ISC leads to cost reduction and climate change mitigation as combustion agents are used and heat is generated in situ.

Other common strategies which have been investigated for heavy oil development include the Cold Heavy Oil Production with Sand (CHOPS) method\(^22\)\(^-\)\(^24\) which has been employed to reservoirs with less than 5-m depth. Cold production provides immense benefits in reservoirs where gas-oil ratios are high (10-20 m\(^3\)/m\(^3\)) and viscosities are in the range of 1000-50 000 cp.\(^25\) This process leads to the formation of foamy oil which enables fluid flow to the surface. Most times, this oil encounters sand which aid in the creation of wormhole networks.\(^26\)

Application of the CHOPS technique has been known to produce an extra 5% recovery from the lone use of cold production.\(^22\)\(^,\)\(^23\)

Other methods which have been employed include the vapor extraction processes (VAPEX) where pure hydrocarbon vapor is employed in place of steam in a process similar to the SAGD,\(^27\)\(^,\)\(^28\) toe-to-heel air injection (THAI),\(^29\)\(^,\)\(^30\) and in situ catalytic upgrading.\(^31\)\(^,\)\(^32\)

The widespread development of these technologies has seen its application in many formations across the world. Edmunds et al\(^33\) looked into prospects for bitumen recovery in Grosmont Formation in Alberta, Canada. Of the various methods tested, cyclic steam stimulations were found to be the most effective. One of the wells, 10A-5-88-19W4 produced about 100,000 bbls of oil after 10 cycles with cumulative steam-oil ratio (SOR) of six. Analogous evaluation of steam injection applicability in Iranian fractured oil fields was conducted by Bahonar et al.\(^34\) A case study was conducted using data of a naturally fractured carbonate oil field having 3.6 billion barrels of initial oil in place. The oil in this reservoir had very high density (7.24 API) and viscosity (2700 cp). Analyses indicated that steam injection could assist in increasing recovery factor up to 12%. It was determined that increase in steam quality caused a slight, almost insignificant increase in oil recovery. In addition, it was observed that maximum recovery could be achieved by keeping injection rates as low as possible. Vologodskiy et al\(^35\) performed studies on the Russkoye oil field in Russia with 1.3 billion ton of oil in place. Besides the high oil density and viscosity found in this field, development process was complicated by the high heterogeneity of the formation. Pilot tests conducted in the oil field included cold and hot water injection. After 2 years of hot water injection, water cut increased from 20% to 45%. Four months after the start of cold water injection, water breakthrough occurred which resulted in water cut increase till 99% and well shut-in. Chemical EOR in the Bamboo heavy oil field, Muglad Basin in Sudan increased recovery by approximately 57%.\(^36\) Primary depletion allowed for recovery factor to reach 18% while EOR increased recovery to 75% of the estimated ultimate recovery. Significant development of the field was inhibited by high water cuts. Initially, oil rate amounted to nearly 20,000 STB/day. The onset of water breakthrough led to increased water production thereby decreasing oil rate to about 8000 STB/day. After relatively nonsufficient primary recovery, the option of thermal injection seemed to be attractive. However, “huff-and-puff” injection of chemicals was found to be the
most effective. Chemical enhanced oil recovery process consisted of cyclic injection of chemicals into the formation that generated an oil-rich colloidal dispersion which decreased viscosity value significantly.\(^{36}\)

Despite advancements in technology development and applications in heavy oil reservoirs, there exist significant concerns in the exploitation of this resource. One common setback in application of CSS is the early onset of steam breakthrough due to steam gravity override.\(^{37,38}\) This problem has informed the need for this study where we attempt to minimize the early steam breakthroughs and improve recoveries in heavy oil reservoirs undergoing CSS by employing fishtail wells. Well configurations and technology have been proven to increase recoveries from oil reservoirs and are classified as improved oil recovery techniques.\(^{39,40}\) These configurations could vary from the spacing between the wells, design of the wells, placement of the well among others.\(^{40,41}\) Generally, the aim of these well technologies is improvement of sweep efficiency from the reservoirs. Infill drilling is a popular well development technique where more wells are drilled to reduce spacing between wells and maximize sweep.\(^{40}\) Well design patterns have over the years ranged from vertical, horizontal, and multilateral wells.\(^{41,42}\) Placement of wells involves the application of pattern flood techniques such as spot patterns, for example, five spot, seven spot, and nine spot, line drive patterns, and their modifications.\(^{43,44}\) Fishtail wells as a form of multilateral well can be said to be a well whose laterals extend from a single horizontal mother wellbore.\(^{39,45}\) The ability of fishtail wells (Figure 1) (sometimes referred to as fishbone wells) has been proven by a few authors.\(^{39,46}\) Its performance stems from the improved contact areas of the wellbore with the formation due to its branches.\(^{39,47}\) Ayokunle and Hashem\(^{39}\) performed design optimization studies using design of experiments and response surface methodology to investigate the application of fishtail wells to heterogeneous reservoirs with favorable impact of fishtail wells on improving production from reservoirs. Salas et al\(^{42}\) showed the potential of multilateral wells in improving recoveries from heterogeneous reservoirs by sweeping unswept oil. To analyze the impact of the use of well technologies and enhanced oil recovery processes to produce oil from heavy formations, Al Hadabi et al\(^{48}\) made use of steam control valves in minimizing heat loss from steam. They conducted their study using a commercial software package on a field in Oman. Their implementation of the trap valve was achieved by placing controls on flow rate and pressure of producer wells. Their results were able to prove the efficiency of using a valve as equal temperature distributions were observed across the model ensuring better recoveries. Fipke and Celli\(^{41}\) showed the successful application of multilateral well technology to improve economics of the Petrozuata project in Venezuela. Their study demonstrated the economic value of the use of multilateral technology to full-scale development projects. Zhou et al\(^{49}\) in their study affirmed the improved performance capabilities of fishtail wells compared to conventional wells when applied to heavy oil reservoirs. Zhou et al\(^{50}\) showed the effect the twin application of fishtail wells and polymer injection had on improving recovery in an oil sands reservoir. Their study also showed the reduction in cSOR by 47.8% of conventional SAGD. Although these studies have shown the potential of fishtail wells for heavy oil reservoirs, the joint application of CSS and fishtail wells has not yet been demonstrated. In this study, we simulate cyclic steam stimulation in fishtail wells to improve steam contact areas and minimize steam breakthrough in the Yarega heavy oil field in Russia.

Specifically, this research focuses on presenting results on the development of a naturally fractured heavy oil reservoir in the YHOF located in Russia. We employ numerical simulations of coupled heat and fluid flow during steam injections.
for this analysis. For the purpose of this study, the reservoir will be identified as sector “N.”

2 | GEOLOGY OF THE YAREGA HEAVY OIL FIELD (YHOF)

Yarega oil field is located 18 km from Ukhta, a city in Komi Republic of the Russian Federation. The oil field is situated within the limits of large, low-angle, and asymmetric Ukhta fold system. It is 36 km in length and 4-6 km in width.51 Commercially attractive reserves are situated in formation III related to mid-Devonian depositions of Givetian period. Formation III is located at depths between 130 and 220 m in the sandstones of middle Devonian directly on metamorphic shales of Riphean age and covered with mid-Devonian argillites (Figure 2). Above the argillites, there is a tuft-diabase layer and sand-argillite stack of the upper Devonian. The formation is represented with weakly and medium-consolidated sandstones consisting of quartz feldspar grains that are cemented with ferruginous-carbonate and clay material. Average effective thickness of the formation is 26 m. The Yarega and Lyael oil pools are very asymmetric and have flat wings (from 1 to 3°) extended along northeastern direction.52

The Ukhta fold system is about 225 km (long axis) and 60 km (short axis). In the arch of the fold, several local flat dome-like structures are found with lengths from 10 to 15 km. The Yarega oil field lies in one of these domes. Dimensions of this fold are 12.5 km (along the axis) and 1.5-4.5 km in width. The fold is asymmetric (its northeastern wing is almost three times wider than southwestern).52

All rock types are fractured (to a variable degree) and closed with disjunctive faults. There is a big influence of these faults on productive deposits (oil), because these faults affect the porosity and permeability of the formation. Detailed study of the disjunctive fault system, fractures in the formation, and crossing/underlying rocks is conducted during the building of mine shafts and corridors, and mine development techniques.53

Disjunctive disruptions of the oil field are represented with relatively large fractures. Some of them are closed/filled while others are opened or accompanied with the fracturing. These faults and fractures cut different layers of the oil field with the larger faults having lengths from 1 to 3 km with offsets of 5-10 m. Average-sized faults have lengths of hundreds of meters with offset of 2 m. Little disjunctive fractures and faults have lengths of tens of meters and offset of 0.5 m. All these fractures are easily visible inside the mine corridors and shafts. Also, sometimes the presence of these fractures is evident because of steam/water/oil breakthroughs in the neighboring wells. The network of microfractures is visible only in thin sections.53

According to mine excavation data, formation III of Yarega oil field is fractured with steep (from 60 to 80°) fractures that break the reservoirs into multiple blocks having various shapes and sizes. Diagonal system of fractures prevails (in relation to the overall extent of the structure). However in some places, northwestern and southeastern trending fractures appear more dominant. These fractures can vary in length from 10 m to as large as 2.5 km. Fracture spacing in the upper parts of the formations is 25 m, while fracture spacing in the lower formations is in the range of 7.6-12.5 m.54

The reservoirs in the Yarega oil field are composed of medium- and fine-grained sandstones, with some silt and clay zones/layers. The basement is massive quartzite of Riphean age above which lie graphitized shale formations. The Yarega reservoirs overlie these shale layers. The porosity and permeability distributions are shown in Figure 3.
2.1 | Geology of sector N

This study is focused on examining a reservoir (reservoir “N”) in Yarega heavy oil field (YHOF) for development strategies and production optimization. Reservoir N is a naturally fractured heavy oil reservoir and located in sector 2 of YHOF (Figure 4). The formation extends 130-220 m in the sandstones of upper and middle Devonian period. Average pay zone thickness of the formation is 26 m, average porosity of the formation is 25%, and average matrix permeability is 2 mm².

The reservoir is crisscrossed by fractures every 20-25 m. Significant variation of the fracture sizes and permeabilities led to division into two types—macrofractures and microfractures. Both types of fractures happen to be exposed to well-formation contact. As a result, initial oil rate of some of the wells was sometimes 5-15 metric tons/day and other times reached 100 metric tons/day.

Oil occupying the porous space of the rock has abnormally high viscosity: up to 18 000 cp. Initial reservoir pressure is 1-1.3 MPa, and oil density at reservoir conditions is 933 kg/m³ and at surface conditions—945 kg/m³. Oil has low content of sulfur (up to 1.1% of total oil mass) and paraffin (up to 0.5 of total oil mass). More detailed description is shown in Table 1. Matrix is tight, whereas the fractures act as high permeability pathways in a manner similar to dual porosity reservoirs.

3 | MATHEMATICAL MODEL

The numerical structure under which the assessment will be based is derived from the fundamental laws of conservation of mass, momentum, and energy together with closure relations involving phase equilibrium, relative permeabilities, and capillary pressures. In the following derivations, we assume reactions do not occur. Reactions have been proven to be important in certain studies but we assume they do not occur here in the timescales considered and given that the geology is that of siliciclastic rocks which are less reactive compared with other rock types. The reservoir has no communication with any aquifers, and capillary pressures are considered negligible.

The continuity equation which is a statement of the conservation of mass can be written as (assuming no source or sink).

$$\frac{\partial \rho}{\partial t} + \nabla \cdot (\rho \mathbf{u}) = 0$$  \hspace{1cm} (1)$$

where $\rho$ is rock density, $t$ is time, $\nabla$ is the divergence operator, and $\mathbf{u}$ is the Darcy velocity. By Darcy law, the velocity can be written as in Equation (2) thus obeying the conservation of momentum.

$$u = -\frac{k}{\mu} \left[ \nabla p - \rho g \nabla z \right]$$  \hspace{1cm} (2)$$
where \( k \) is permeability, \( \mu \) is viscosity, \( p \) is pressure, \( \rho_f \) is fluid density, \( \nabla \) is gradient operator, \( g \) is acceleration due to gravity.

For flow in porous media, the equations for conservation of mass and momentum can be expressed as:

\[
\frac{\partial}{\partial t} \left( \phi \rho_f \right) - \nabla \cdot \left( \rho_f \frac{k}{\mu} \left[ \nabla p - \rho_f g \right] \right) = Q_f = 0 \quad (3)
\]

where \( \phi \) is porosity, \( Q_f \) represents fluid withdrawal or injection; all other symbols have their standard meanings.

Equation for conservation of energy can be written as:

\[
\frac{\partial}{\partial t} \left[ \phi \rho_f U_f + (1-\phi) \rho_s U_s \right] - \nabla \cdot \left( \rho_f \frac{k}{\mu} \left[ \nabla p - \rho_f g \right] H_f \right) + \nabla \cdot (K \Delta T) - Q_h = 0 \quad (4)
\]

where \( U \) is internal energy, \( T \) is temperature, \( K \) is thermal conductivity, \( Q_h \) is heat source/sink, \( H \) is enthalpy, subscripts \( f \) and \( s \) represent fluid and solid phases, respectively.

In addition, to observe the effect of fractures, dual porosity models were employed in the simulations. Dual porosity models are models in which the matrix transfers flow to the fractures and from the fracture to the wellbore (Figure 5).

Change in the matrix pressure is assumed negligible in dual porosity models. Model equations for dual porosities can be summarized as below:

![FIGURE 4 Schematic map of YHOF (modified after52)](image)

| Property (units)                  | Value                                      |
|-----------------------------------|--------------------------------------------|
| Absolute upper boundary level (m) | −24 (from −62 till +16)                   |
| Absolute depth of OWC (m)         | −60                                        |
| Type of deposition                | Sheet, roof                                |
| Type of reservoir                 | Terrigenous, porous fractured reservoir     |
| Payzone area (thousand m\(^2\))   | 24 370                                     |
| Average total thickness (m)       | 44                                         |
| Average payzone thickness (m)     | 10.9                                       |
| Average matrix permeability (D)   | 2.23                                       |
| Average porosity (unitless)       | 0.25                                       |
| Initial oil saturation (unitless) | 0.86                                       |
| Initial formation temperature (°F)| 46.4                                       |
| Initial formation pressure (psi)  | 159.54-203.05                              |
| Bubble point pressure (psi)       | 65.27                                      |
| Oil density at reservoir conditions (°API) | 20.02                             |
| Oil density at surface conditions (°API) | 18.09                             |
| Oil viscosity at reservoir conditions (centipoise) | 12 000                             |
| Oil formation volume factor       | 1.02                                       |
| Water density at reservoir conditions | 62.55                              |

**TABLE 1** Reservoir properties of a middle + upper sectors of formation III of reservoir N
\[
\frac{\partial}{\partial t} \left( \rho_f \phi_f \right) = \nabla \cdot \left( \rho_f \phi_f \left[ \nabla p_f - \rho_f g \right] \right) - \dot{Q}_f + T_{m-f} = 0
\]  

(5)

where \( T_{m-f} \) is the matrix-fracture transfer term, \( f \) stands for fracture, \( m \) stands for matrix.

\[
T_{m-f} = \frac{1}{\rho_m} \left( \frac{k_m}{\mu} \right) (P_m - P_f)
\]

(6)

where \( \sigma \) is the interporosity shape factor, \( P \) is pressure, and subscripts \( m \) and \( f \) stand for matrix and fracture, respectively.

For multiphase multicomponent flow, the equations can be modified to include saturations and mole fractions in one dimension for the three phases as.

\[
\frac{\partial}{\partial t} \left[ V_f \left( \rho_w S_w w_i + \rho_o S_o x_i + \rho_g S_g y_i \right) \right] =
\sum_{k=1}^{n_f} \left[ \frac{kA}{l} \left( \frac{k_{rw}}{\mu_w} \Delta \phi_w \rho_w w_i + \frac{k_{ro}}{\mu_o} \Delta \phi_o \rho_o x_i + \frac{k_{rg}}{\mu_g} \Delta \phi_g \rho_g y_i \right) \right] +
\sum_{k=1}^{n_f} \left[ \frac{A}{l} \left( D_w \phi_w \Delta w_i + D_o \phi_o \Delta x_i + D_g \phi_g \Delta y_i \right) \right] - \dot{Q}_f + T_{m-f}
\]

(7)

\[
\dot{Q}_f = \rho_w \dot{q}_{wk} w_i + \rho_o \dot{q}_{ok} x_i + \rho_g \dot{q}_{gg} y_i
\]

(8)

where \( V_f \) is fluid volume, \( S \) is saturation, \( k \) is relative permeability, \( \phi \) is \( D \) is dispersivity coefficient, subscripts \( w, o, g, i \) represents water, oil, gas, and components, respectively, \( w, x, y \) are the mole fractions of water, oil, and gas, respectively, \( k \) represents the well layer, \( q \) is flow rate; all other symbols have their previous meanings.

Similarly, energy conservation can be written as.

\[
\frac{\partial}{\partial t} \left[ V_f \left( \rho_w S_w w_i + \rho_o S_o x_i + \rho_g S_g y_i \right) \right] =
\sum_{k=1}^{n_f} \left[ \frac{kA}{l} \left( \frac{k_{rw}}{\mu_w} \Delta \phi_w \rho_w H_w + \frac{k_{ro}}{\mu_o} \Delta \phi_o \rho_o H_o + \frac{k_{rg}}{\mu_g} \Delta \phi_g \rho_g H_g \right) \right] +
\sum_{k=1}^{n_f} K \Delta T - \dot{Q}_h + T_{m-f}
\]

(9)

The set of equations above are impossible to solve by analytical methods except simplifying assumptions are made. Therefore, numerical methods are used in this study. The finite volume method is employed here for discretization due to its advantages of local conservation in every grid block and its ease of application on unstructured grids. With the use of the commercial package CMG-STAR 2017,57 we obtain solutions to the final set of matrix equations using Newton-Raphson iterations. CMG-STARs has been used in the modeling of heavy oil-related problems for several years with great accuracy.11,58,59 A high-performance computing cluster (HPCC) system was used to run the simulations for computational speeds.

### 4 | RESERVOIR MODEL

The reservoir model employed consisted of 23 760 grid blocks with six blocks in the \( X \) direction, 20 blocks in the \( Y \) direction, and 198 blocks in the \( Z \) direction (Figure 6). The reservoir model was upscaled from a static model using flow-based upscaling algorithms to ensure properties of the reservoir are representative. The static model was developed employing data from petrophysical cores, integrated logs, and seismic surveys. The sequential Gaussian simulation (SGS) algorithm was used for populating the model with static reservoir properties. Initial reservoir temperature and pressure are 10 C and 600 kPa at 60 m. A depth average capillary-gravity method was used in vertical equilibrium calculations. Grid sensitivity studies were carried out to ensure numerical dispersion effects were minimized. Final grid size parameters and reservoir static and thermal parameters used in the simulations are summarized in Table 2 below.

Relative permeability curves for this study were derived from coreflood laboratory experiments. A core sample from one of the wells in the studied sector of Yarega oil field was used in the experiment. Oil and water were initially drained from the sample using a centrifuge. Thereafter, the core was saturated with brine using a saturator. Core was placed in a core holder, and a sample oil from the Yarega field was injected into the core to create both initial oil and
water saturations. Injection was stopped on production of oil. Thereafter, water was injected into the core to displace oil in the core. All volumes of oil and water produced from the core were measured as well as the water injected into the core. Steam/oil relative permeability curves were derived by injection of steam. The JBN method\textsuperscript{60} was used for the determination of the curves from the experimental data (Figure 7).

The system was modeled using a two-component system consisting of steam and oil. Fluid parameters used are typical of the oil in the YHOF. Phase partitioning is determined using the K-value-based compositional model at every grid block and time step. To obtain solutions to the problem, no flow boundary conditions were employed at all boundaries of the reservoir. Distance between the wells in vertical direction varies from 6 to 10 m.

### TABLE 2  Input parameters used in simulation model

| Grid parameters                      | Value (units) |
|--------------------------------------|---------------|
| Grid blocks total                    | 23 760        |
| Average grid block dimensions        | 2 m by 2 m by 0.035 m |
| Matrix Permeability                  | 0–15 000 (md) |
| Fracture Permeability                | 50 000 (md)   |
| Fracture Porosity                    | 0.02          |
| Grid Thickness                       | 7 (m)         |
| Reservoir Temperature                | 10 (c)        |
| Porosity Reference Pressure          | 600 kPa       |
| Formation Compressibility            | 1.4E–5 (1/kPa) |
| Thermal Expansion Coefficient        | 12.5e–6 (1/C) |
| Volumetric Heat Capacity             | 2 400 000 J/(m$^3$ C) |
| Injected steam quality               | 0.8           |

### RESULTS AND DISCUSSION

#### 5.1 Baseline simulation

High injectivity required for providing injection volumes of water in the form of steam was obtained only after introducing secondary media (dual porosity) with relatively high fracture permeabilities. The presence of highly permeable fractures in the considered sector has been proven in the YHOF by tracer tests conducted after drilling of the SAGD pair. Fractures in the domain assist in distribution of steam in the reservoir and provide necessary conduits of high permeability for highly viscous oil but also contribute to drastic increase of water cut after the initiation of production and early steam breakthroughs.

Fishtail well design was implemented in the sector N and compared with the other well and injection configurations such as SAGD and CSS. Fishtail configuration was chosen with four lateral branches extended to the left and right from the well stem. Branches had vertical elevation and horizontal extension in order to facilitate maximum sweep of the volume of the reservoir, thus improving oil mobility. Generally, branches were chosen to extend vertically up to 5 m from the upper reservoir boundary. In this study, the fishtail wells were placed at the middle of previously existing SAGD pairs and extended to the limit of the SAGD pairs (Figure 8).

A comparison of recovery for the different well design and injection strategies, particularly, the Fishtail-CSS, SAGD, and SAGD-CSS design configurations is made. As observed, the fishtail well configuration gave the highest production (Figure 9). In assessing further the reason for the higher recovery for the improved recovery from the fishtail
wells, steam chamber and SOR plots were made for the three designs (Figure 10). Steam chamber can be thought of as an area in the reservoir where steam agglomerates and latent heat is discharged into the immobile oil.\textsuperscript{61,62} As seen from Figure 10, the steam chamber volume occupied by SAGD was significantly greater than the volume occupied by both the SAGD-CSS and the Fishtail-CSS designs. The reason for the significant steam chamber but lower oil production is most likely due to heat losses. Heat losses during steam injection can be due to the overburden or underburden, aquifers surrounding the reservoir of interest, steam chamber condensations, or low steam conformance. As neither of the wells were shut-in during the monitoring period, we can deduce that no steam chamber condensations have occurred. Closed boundary conditions were used for the simulations; hence, the possibility of heat losses to surrounding aquifers is nonexistent. The major reason for the reduced recovery was therefore the poor steam conformance of the reservoir. Steam conformance refers to the volume of the reservoir actually contacted by the steam.\textsuperscript{63,64} Contour plots in Figure 11 show that steam injected during SAGD was able to penetrate the fractures better leading to higher initial recoveries till the fractures got depleted. In Fishtail-CSS, there was better penetration of both the matrix and the fractures leading to a more sustained production from the reservoir as can be seen from Figure 12.

The reason for this irregularity in steam conformance could be the result of the heterogeneity of the media which meant that hydraulic conductivity in the fractures would be greater than that in the matrix leading to fast upward movement of steam through the fracture blocks. Furthermore, wellbore hydraulics is also postulated as a reason for this preferential flow of steam into fractures. Factors affecting the wellbore such as irregular steam pressures during injection, formation damage, and multiple steam injection points at uniform locations could have impacted the fixed upward distribution of steam in the domain.\textsuperscript{59,65} The improved contact points by the fishtail wells, as well as the cyclic injection strategy, meant better steam conformance was achieved and a more sustained recovery was derived from the reservoir.

The importance of SORs in assessing the efficiency of any thermal process cannot be understated. Steam-oil ratios indicate the efficiency of the process, cost implications, and ultimately decreased carbon footprints. Figure 10 shows the SOR for the three cases. It can be seen that the fishtail design scenario provided the least SOR indicating the efficiency of the steam used in the reservoir. Conversely, SOR for the SAGD scenario was the highest suggesting inefficiency of the strategy and possible heat losses. Another advantage of fishtail wells is the conversion of the injector wells to producer wells at every instance of an injection cycle, hence maximizing all available perforation for production.

5.2 Energy efficiencies

In recent times, energy efficiencies of processes have generally become more important. Several industries work to ensure more value is derived for the same amount of energy input. Production of steam involves the burning of fuels which contribute to the greenhouse emissions of the world. Large amounts of produced water imply lots of post-treatment is required before the water is re-injected or disposed. Therefore, we investigate the efficiency of the system using cumulative energy-oil ratios (cEORs). Energy production is dependent on several factors among which are energy required for steam production, air compression, treatment of water, fluid injection, and fluid transportation if steam production site is far from usage location, artificial lift among others. According to work by Wang et al., the cEOR can be determined using the following equation (assuming energy
for compressing air is included and a once-through steam generator (OTSG) is utilized)

cEOR = \frac{cSOR (H_{s,sg} - H_{fw})}{\eta} \rho_w \times 10^{-6} + \frac{P_{sc} V_{air} ln P_{inj}}{V_{oil}} P_{sc} \times 10^{-3}

H_{s,sg} = (1 - x) H_l + x H_v

where $H_{s,sg}$ is the specific enthalpy of injected steam, $H_{fw}$ is the specific enthalpy of steam at ambient conditions, $H_l$ is the specific enthalpy of the liquid phase, $H_v$ is the specific enthalpy of the vapor phase, $\rho_w$ is the density of feed water, $cSOR$ is the cumulative SOR, $\eta$ is the thermal efficiency of the steam generating process, $P_{sc}$ is the atmospheric pressure of water, $P_{inj}$ is injected pressure, $V_{air}$ is injected air volume, $V_{oil}$ is oil production volume, and $x$ is the steam quality.

However, in this study, we ignore the energy derived from compressing air as this is not the focus of this study. Figure 13 shows the cEOR for the designs tested. In a similar trend to the SOR, it can be seen that SAGD processes employed in this reservoir would require more energy per m³ of oil produced from the reservoir (about four times more than the other strategies), hence providing an indication of the inefficiency of this strategy.

5.3 | Sensitivity and uncertainty analyses

5.3.1 | Fixed CSS injection cycles

Fishtail well design showed to be the most effective development strategy when implemented with cyclic steam stimulation (CSS). Cycles consisted of injection, soaking,
and production periods. Three different one-month injection soaking production cycles were assessed: 3-day injection, 3-day soaking, and 24-day production; 6-day injection, 6-day soaking, and 18-day production; and 10-day injection, 10-day soaking, and 10-day production. These cycles were carried out for the entire duration of the simulation. Results show the 10-10-10 cycle produced the best performance of the three cases (Figure 14). Though some literature studies proposed a 10% injection, 10% soaking, and 80% production optimum scenario, our simulations proved otherwise; which implies that the best strategy for CSS cycling may be peculiar to each case. The opportunity cost for this improved recovery appeared to be the increased water production by the Fishtail 10-10-10 scenario (Figure 14). The reason for the improved recovery for the Fishtail 10-10-10 can be seen from Figure 15 where the steam chamber volume for the best scenario was more than the other scenarios. In addition, the SOR for the best scenario was also low implying lower heat losses which meant improved recoveries and great economics.

5.3.2 Variable CSS injection cycles

In order to investigate whether a direct relation existed between the cumulative production and the injection period, further tests were carried out with longer durations of the injection phase. In these cases, the lengths of each cycle were extended beyond 1 month to analyze the impact of possible prolongation of any of the cycle periods (injection, soaking, and production) and their effect on displacement efficiencies. Four extra cycles were tested: 20-day injection, 10-day soaking, and 10-day production (20-10-10); 20-day injection, 10-day soaking, and 30-day production (20-10-30); 40-day injection, 10-day soaking, and 30-day production (40-10-30); and 40-day injection, 20-day soaking, and 60-day production (40-20-60). Total run time for each of these scenarios remained fixed. Oil production using fishtail well with cycle regime 10-10-10 provided the best production when compared with increased injection times for the individual periods (Figure 16). The reason for this increase in the production is due to the improved steam chamber offered by this technique and the reduced SOR.
The 40-20-60 and 40-10-30 gave the least recovery from the reservoir indicating an extended injection period may mean that heat losses into the overburden/underburden occur for a long period and thus may inhibit production from the reservoir. Results also imply that prolonged injection leads to a rapidly dissipating steam front due to heat losses. The leading edge of the steam front would lose heat to the overburden while the lagging end would be left with less latent heat to mobilize the oil. This ensures that the steam chamber volume at the beginning of the production cycle as shown in Figure 18B,D is minimal for the elongated injection period as opposed to the

**Figure 12** 3D temperature profiles for the Fishtail-CSS. The top shows the temperature profile (equivalent to steam chamber) for the fractures after 10 days and at the final time step; bottom shows the temperature profile for the matrix after 10 days and at the final time step.

**Figure 13** Cumulative energy-oil ratio for the three designs.
shorter injection cycle. Heat losses can also be confirmed from Figure 18A,C where at the end of the injection phase, the steam volume from the elongated cycle is considerably less than the volume in the shorter cycle. A longer soaking period with lower heat availability does not lead to enough mobile oil being fed into the laterals of the fishtail when production is resumed. Based on conclusions from the previous sensitivity and this sensitivity, it is recommended that a case-by-case analysis be performed on candidate reservoirs prior to deployment of any Fishtail-CSS strategy.

5.3.3 | Injection pressures

Operational parameters provide an important indication on the performance of steam-related flooding process. An important parameter which was investigated was the injection pressures. Higher steam injection pressures could mean that more steam can permeate the formation as quickly as possible. However, this also means that the steam flows to the top of the reservoir rapidly and may lead to heat losses to the overburden or underburden faster than at lower injection pressures. To assess whether our case would lead to improved oil recovery or losses to the overburden, two new injection pressures were tested. 2200 kPa (labeled as injection pressure 1) was tested as a lower value while 2800 kPa (labeled as injection pressure 2) was tested as a higher value together with original pressure of 2500 kPa to provide a range of values. Results (Figure 19) show that while higher injection pressures did not necessarily lead to significant production from the reservoir, lower injection pressures may lead to lower production rates. Water cut percentages (Figure 20) also appear to be commensurate
with the amount of oil recovered from the reservoir. With higher injection pressures, more steam would be delivered to the system and that can be seen with the very slight increase in the recovery from the reservoir. But, this increase may not be worth the amount of energy required for injection suggesting an optimum injection pressure is required.

5.3.4 | Steam quality

While keeping the injection pressure constant at 2500 kPa, steam quality was varied between 0.6 and 0.9. A higher steam quality ensures that the mixture of condensate being injected into the process contains more saturated steam than saturated liquid. The implication of this is that more latent energy is delivered to the system and therefore more heat is available to mobilize the oil in the reservoir. Sometimes in steam production, steam quality may drop as a result of several process variables. Consequently, it was imperative to study the likely effect of a variation in the steam quality delivered on reservoir performance. Figure 21 shows the minimal impact which changes in the steam quality may have on the production performance. Cumulative oil and water production plots from the three scenarios tested show minimal changes. This suggests that it may be more important to get heat into the system than it is to maintain a certain quality of heat delivered to the system. A summary of all sensitivities is shown in Table 3.

6 | CONCLUSIONS

Heavy oil reservoir development comes with certain drawbacks, among which are early steam breakthroughs, rapid heat losses, and unfavorable SORs among others. In this
study, we have proposed the use of the fishtail well configuration together with CSSs to improve oil recoveries in heavy oil developments. Three-dimensional numerical simulations were run on a reservoir in the Yarega heavy oil field in Russia. Currently produced using SAGD approach, a major problem encountered in the facility was the only onset of steam in producer wells and diminishing recoveries.

Cyclic steam injections coupled with fishtail well design were simulated and compared to the currently employed SAGD approach and a CSS injection strategy with SAGD. CSS assisted in immobilizing the oil while fishtail well design reduced the travel time for the mobilized oil to reach a nearby producer well or for the steam to lose its heat before it condenses. Recovery for the fishtail-CSS strategy was 33% higher than that of conventional SAGD after about

**FIGURE 18** Steam chamber volumes for the elongated injection period (40-20-60) annotated with (a) and (b) and the shorter injection cycle (10-10-10) annotated with (c) and (d)

**FIGURE 19** Sensitivity plots showing cumulative oil and water production for different steam injection pressures
2 years. In addition, water production with this strategy was about 83% lower. Cumulative energy-oil ratios show fishtail-CSS to be four times more efficient than conventional SAGD in producing oil. While the presence of fractures in the fishtail was able to improve the steam conformance with fishtail wells, fractures in SAGD led to a rapid upward movement of steam and poorer steam conformance. Results from this work show that the dual use of these two techniques possess the ability to improve oil production and reduce steam breakthrough. Though the study has shown advantages, results could vary if the process is subject to different operation parameters. Besides its technical advantage, our study has also shown that fishtail wells could lead to reduced SORs, which is an indication of economic viability. Though our study has shown viability, we recommend a more detailed cost analysis study be performed where the cost for drilling fishtail wells, steam generation, and environmental impacts are put into consideration.
**TABLE 3** Summary of sensitivity analyses

| Sensitivities                  | Cumulative oil production (m³) | Cumulative water production (m³) |
|--------------------------------|--------------------------------|---------------------------------|
| Fixed CSS cycles               |                                |                                 |
| Fishtail 3-3-24                | 1300                           | 1900                            |
| Fishtail 6-6-18                | 2100                           | 6000                            |
| Fishtail 10-10-10              | 2700                           | 9000                            |
| Variable CSS injection cycles  |                                |                                 |
| Fishtail 10-10-10              | 2700                           | 8050                            |
| Fishtail 20-10-10              | 2600                           | 9900                            |
| Fishtail 20-10-30              | 2000                           | 5000                            |
| Fishtail 40-10-30              | 1900                           | 4500                            |
| Fishtail 40-20-60              | 1550                           | 3800                            |
| Injection pressures            |                                |                                 |
| 2200 kPa                       | 2400                           | 7000                            |
| 2500 kPa                       | 2850                           | 9900                            |
| 2800 kPa                       | 2850                           | 11,000                          |
| Steam quality                  |                                |                                 |
| 0.6                            | 2550                           | 9000                            |
| 0.7                            | 2900                           | 9500                            |
| 0.9                            | 2850                           | 8500                            |

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