

Review article

A critical review of cold heavy oil production with sand (CHOPS): Mechanisms, modelling advances, and field applications

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ABSTRACT

Extensive oil sand deposits are found worldwide, with the largest and most significant reserves located in Canada (approximately 2.2 trillion barrels) and Venezuela, followed by smaller accumulations in Kazakhstan and Russia. Collectively, the volumes of unconventional oil contained within these oil sands surpass the conventional reserves of all other nations combined. If even 30% of this resource were technically and economically recoverable, it would be sufficient to meet North American energy demand for more than a century, based on 2002 consumption levels. These reserves therefore represent an abundant supply of oil with considerable economic significance. The extraction and transportation of oil from these deposits demand advanced technological approaches. Of the various extraction approaches available, CHOPS, Cold Heavy Oil Production with Sand, has established itself as the leading method for recovering heavy crude oil. This non-thermal process involves the controlled initiation and maintenance of sand influx into production wells, facilitated through the use of progressive cavity pumps (PCPs). The approach not only improves production rates but also provides operational reliability. As sand is mobilised, wormholes are formed within the reservoir, generating significant pressure drops along their lengths. The effectiveness of CHOPS is primarily attributed to two mechanisms: the formation of wormholes and the occurrence of foamy oil flow. Typical CHOPS recovery factors are still very low, around 5–15%; and it can be increased during the Post-CHOPS processes only 2–8%. Also, during the CHOPS process, there are some technical challenges which have been described in our current study.

1. Introduction

It is estimated that between six and nine trillion barrels of oil, representing more than two-thirds of global petroleum resources, consist of heavy viscous crude oils that remain technically challenging to extract (Xia et al., 2026; Wang et al., 2025; Alboudwarej et al., 2006). According to Liu et al., (2019), the Americas possess 72.69 billion tonnes of recoverable heavy oil resources, with South America and North America accounting for 32% and 25% of this total, respectively. The Middle East holds 17.67 billion tonnes, representing 14% of global recoverable heavy crude oil, followed by Asia, Russia, Europe and Africa in

descending order, Fig. 1 (Mohamad et al., 2022; Abd-El-Moniem, 2020). Heavy oil reservoirs are widespread globally (Zhao et al., 2026; Du et al., 2025; Ogunkunle et al., 2025, Ayal et al., 2024a). Venezuela, the United States, Saudi Arabia and Mexico represent the four leading countries, together holding 81.72 billion tonnes of recoverable heavy oil resources, equivalent to 64.4% of the global total. Within this group, Venezuela is characterised predominantly by extra-heavy oil production, whereas the other three nations primarily produce heavy oil, Fig. 2. In addition to these major producers, the largest accumulations of oil-sand and unconsolidated resources are found in Canada, followed by Russia. Canada alone holds technically recoverable oil-sand and unconsolidated

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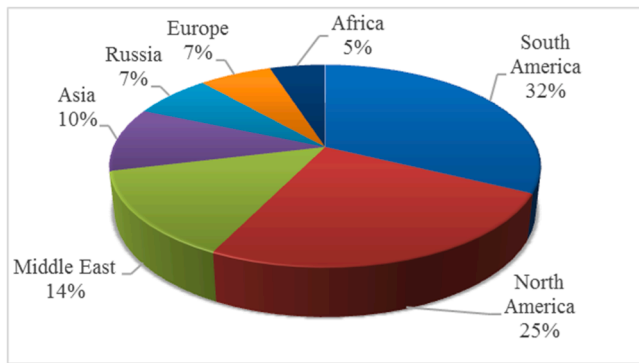


Fig. 1. Technical recoverable reserves of heavy.

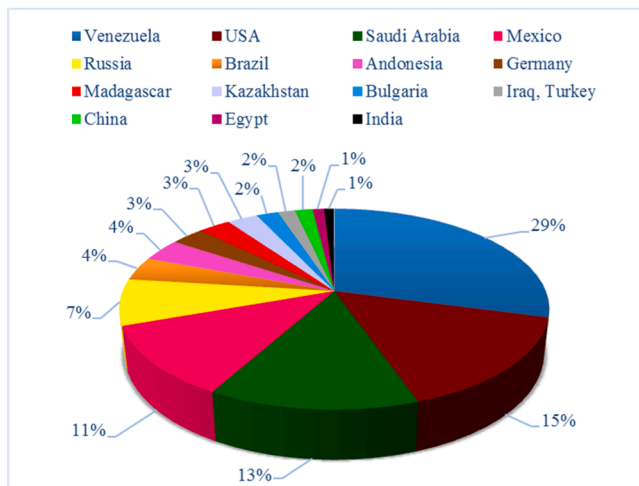


Fig. 2. Technical recoverable reserves of heavy Oil.

deposits amounting to around 30% of the global total. While Russia has not yet undertaken commercial oil-sand production, its estimated resources remain substantial, accounting for approximately 24.37% of worldwide oil-sand reserves under conservative assessments, Fig. 3 (Zhang et al., 2026; Wei et al., 2025; Ayal et al., 2024b; Zheng, 2018).

These reservoirs are typically characterised by shallow burial depths of less than 1800 m, high porosity and permeability, coarse-grained lithology, and weak cementation (Kapadia et al., 2006). Recovery of extra-heavy oil can be improved by applying thermal methods such as steam-assisted gravity drainage (SAGD), vapour extraction (VAPEX), and cyclic steam stimulation, since heat lowers the oil viscosity and allows it to flow more easily.

Nevertheless, because methane is commonly employed as the fuel for steam generation, the associated operating costs remain substantial and continue to rise, typically in the range of CAD\$10–15 per barrel. Moreover, the corrosion failure of tubing is occurred during the thermal recovery methods in the extra-heavy oil reservoirs (Fang et al., 2026; Qazvini et al., 2012). Several years ago Canadian oil companies discovered a non-thermal method to solve the above mentioned problems, referred to as CHOPS, cold heavy oil production with sand (Jiang et al., 2026; Khamitov et al., 2024; Santos et al., 2014; Wang et al., 2001.). Accordingly, this study aims to provide a thorough review of the CHOPS technique.

For this purpose, all of the CHOPS process which has been performed around the world in case of laboratory and field scale, modeling, simulation and optimization studies has been considered. In addition, the petrophysical and geomechanical properties, technical challenges, production mechanisms, experimental and field scale equipment, and post-CHOPS methods have been described.

2. CHOPS: Overview of cold heavy oil production with sand

CHOPS was first introduced in Canada during the late 1980s and reached maturity in the 1990s, becoming widely recognised as the initial production method to be considered for the development of heavy oil in unconsolidated and oil-sand fields (Loughead et al., 1992; Huang et al., 1998; Dusseault et al., 2000a). As a non-thermal recovery technique, CHOPS deliberately initiates and sustains sand influx into wells through the use of progressive cavity pumps (PCPs), thereby increasing production rates and maintaining operational reliability (Dusseault et al., 2000; 2002). In recent years, a chemical dispersant technology has been introduced in the fields at Lloydminster in Alberta, aimed at reduction of the apparent viscosity of fluids produced from wells. By lowering viscosity, this approach decreases the power demand on downhole pumps, enables higher rates of pumping, and has been reported to increase cumulative produced oil by as much as 300%. The main benefit is that it wastes no longer on high oil viscosity restrictions on pump speed (Minish et al., 2012). Cold production in Western Canada is intrinsically linked with sand co-production where the research has indicated that when more sand is produced, the oil production is usually high (Huerta et al., 1996; De-Mirabal et al., 1996). There are major heavy oil deposits at Saskatchewan and Alberta with thousands of wells to the northeast and southeast of Lloydminster under CHOPS. Such a method falls under the category of cold since it does not involve the input of thermal energy, e.g., steam injection. Due to the nature of the reservoir rock, sand is formed in large quantities together with the oil. Over the past 15–20 years, CHOPS has been in extensive use in heavy-oil reservoirs in Saskatchewan. The process is based on progressive cavity pumping (PCP), which is one of the most important innovations, which represented a serious improvement over the previous technologies as far back as 1930s. PCP systems allow an increase in the drawdown (improved suction) of the wells and considerably raise the oil recovery in the reservoir (Crabtree, 2015). CHOPS is widely employed as a non-thermal production technique of heavy crude in the oil slick of eastern Alberta and western Saskatchewan. Its recovery factor generally falls between 5% and 15%, while the average is typically less than 10%. As a result, nearly 90% of the original oil in place (OOIP) is left behind when the process is no longer economically viable, making CHOPS wells and reservoirs attractive targets for enhanced oil recovery (EOR) and further optimisation.

Compared with conventional primary production, CHOPS wells demonstrate significantly higher production rates, a phenomenon attributed to the development of high permeable zones or wormholes. The existence of wormhole formation was observed through both lab studies and field-scale experiments employing fluorescein dyes (Dusseault et al., 1999). A recent application of CHOPS has focused on the production of foamy extra-heavy oil through wells (that are horizontally completed) in the Carabobo sector of the eastern Orinoco Belt. As a primary recovery method, it utilises inherent reservoir energy, including the effects of gas dissolution and expansion, as well as the load imposed by the overburden (Arbelaez, 2023; Walin et al., 2000).

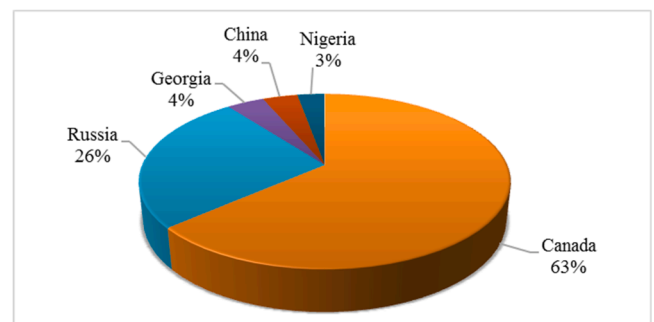


Fig. 3. Technical recoverable reserves of oil-sands.

Subsequent research has demonstrated that the deliberate production of sand facilitates the creation of wormholes within the formation, enabling greater volumes of oil to reach the wellbore. This approach yields superior production rates and recovery, with efficiencies of around 10% compared with 5–6% when sand filters are employed. A major limitation, however, lies in managing the disposal of the produced sand. One earlier practice involved spreading the material on rural roads, which was welcomed by local authorities since the oily sand reduced dust and simultaneously provided road maintenance at no cost. Nevertheless, concerns have arisen regarding the environmental implications of spreading large volumes of oil-laden sand, and in recent years disposal in underground salt caverns has become the preferred option (Shikai et al., 2023).

3. Post CHOPS Methods

Even though sand production encourages more oil production altogether, typical CHOPS recovery factors are still very low, around 5–15% (Alvarez et al., 2009). Any enhanced oil recovery method aimed to increase the oil recovery after CHOPS process becomes uneconomical is named Post-CHOPS. As a cost-effective secondary improved oil recovery (IOR) technique, more than 200 water flooding scenarios (WF) were conducted across Canada from the past six decades in fields with heavy oil reserves (Miller, 2006). However, in post-CHOPS reservoirs, water-flooding typically yields only 2–8% additional heavy oil recovery due to pronounced water channelling (Dong et al., 2006). Among the available options, cyclic solvent injection (CSI) is considered one of the most promising approaches for post-CHOPS recovery (Chang et al., 2012). This process is conceptually similar to cyclic steam stimulation (CSS), for which several analytical models have been proposed by researchers (Seba et al., 1969; Jones, 1977; Gontijo et al., 1984; Sylvester et al., 1988; Gozde et al., 1989). Commercial deployment of cyclic steam stimulation (CSS) has proven effective in a wide range of field projects (Farouq, 1994; Al-Qabandi et al., 1995). Earlier theoretical work by Shelton and Shelton (1973) explored the use of cyclic rich-gas injection for heavy oil recovery, showing that most of the recovery benefits could be realised with only moderate viscosity reduction and relatively short soaking periods. Despite its success, CSS is constrained by the weakness of its driving force, which is insufficient to move significant volumes of heated fluids toward the production well. In response to the limitations of CSS, Butler and co-workers introduced the SAGD technique, which considers paired horizontal wells to facilitate gravity-driven recovery of steam-heated heavy oil (Butler et al., 1981). A solvent-based counterpart to SAGD is vapour extraction, proposed later by Butler et al. (2000). In this approach, gravity provides the main driving force, but its effectiveness diminishes in thin reservoirs where vertical drainage is restricted (Jamaloei, 2013). The slow by nature process of solvent penetration into the viscous oil, and the low gravitational force in shallow net-pay intervals, restricts VAPEX productivity to rates that are not economical. In order to enhance predictive ability, a number of analytical correlations and scaling models have been suggested to reconcile laboratory scale observations with field scale recovery predictions (Butler et al., 1989; Das et al., 1998; Boustani et al., 2001; Karmaker et al., 2003; Yazdani et al., 2005; Nenniger et al., 2008).

Thermal recovery applied after CHOPS is generally regarded as uneconomical due to the problem of the heterogeneity of the reservoir and structural instability. Moreover, the CHOPS wells are not drilled to use in steam operations and the comparatively thin formations where this process is mostly applied render the use of steam injection ineffective. The same is true of solvent injection, where the cost and heterogeneity are also a major challenge. The possible alternative is the combination of solvent and steam. After testing with field data in Alberta, a number of the initial post-CHOPS methods, including thermal, solvent, and steam-solvent hybrid, have been modeled (Rangriz et al., 2016). Solvents-based recovery methods have a number of significant advantages over thermal techniques, including being more energy-efficient,

less expensive, higher quality of recovered oil, partial in-situ upgrading, and less harmful to the environment (James et al., 2007; Butler et al., 1991; Jha et al., 1995; Qazvini et al., 2012). During these processes, the injected fluid enters the heavy oil and dissolves in the viscous fluid and changes the composition of oil-solvent mixture. This interaction facilitates mass transfer and enhances recovery through mechanisms that include lowering interfacial tension, inducing oil swelling, and reducing viscosity (Li et al., 2012; 2013). Given that CHOPS typically leaves 85–95% of the oil unrecovered by the time the production becomes economically unviable, Current research is increasingly directed toward follow-up methods that can recover additional oil from unconsolidated, solution-gas-rich reservoirs while keeping energy use and emissions relatively low. A potential approach is CO₂-based EOR. Injection of CO₂ reduces the viscosity of oil, and if a portion of the injected CO₂ is retained in the formation, the technique simultaneously serves as a carbon storage mechanism. Properly designed, CO₂ follow-up strategies can improve overall recovery factors; for instance, at first 4 production years, cyclic CO₂ injection has achieved incremental recovery of 2.4% with a great return on energy (Sharifi et al., 2017). Another innovative approach is the injection of sodium silicide in cycles in reservoirs after CHOPS, which has been shown to increase the oil recovery factor. Sodium silicide reacts rapidly with reservoir water, generating heat and hydrogen while transforming it to alkali silicates. The principal recovery mechanism is pressure maintenance, which provides additional reservoir energy, supplemented by viscosity reduction. Together, these effects can extend production for a further 5–10 years and add an estimated 25–50% to recoverable reserves under favourable economic conditions (Krumrine et al., 2014). Mathur et al. (2017) investigated the Ugnu deposits of Alaska's North Slope (ANS), which contain more than six billion barrels of oil in place. Their study highlighted a distinctive feature of Alaskan heavy crude oil reservoirs: the close proximity of the hydrocarbon-bearing zone to the permafrost layer, which makes thermal recovery methods impractical. Under such conditions, miscible gas scenarios and polymer flooding represent favourable non-thermal secondary and tertiary recovery options. The team assessed the effect of polymer injection in a reservoir previously produced using CHOPS, reporting an incremental recovery of nearly 12% compared with natural depletion.

Anderson et al., (2019) performed several core-flood tests on oil sands to examine the effect of many commercially available solvents and to determine the most suitable option for a CSI pilot test. The evaluation was based primarily on oil recovery and solvent recovery, with tests conducted on blends of CH₄/C₃H₈, CO₂/C₃H₈, CH₄/C₂H₆, pure C₂H₆, and N₂. Additional sensitivity studies explored the effects of depletion rate and blowdown pressure. Among the solvents tested, pure ethane achieved the highest recoveries for both oil and solvent and required the fewest operating cycles. Nevertheless, because of the limited commercial supply of C₂H₆ and previous field experience with CH₄/C₃H₈ in Husky Edam's (cyclic solvent injection pilot test), a CH₄/C₃H₈ blend was ultimately proposed for pilot implementation at Manatokan East, near Bonnyville, Alberta. Coskuner (2020) studied on the Lloydminster field in Saskatchewan. Enhanced oil recovery following CHOPS has been widely investigated, as the primary CHOPS mechanism typically recovers only about 8% of the OOIP. This leaves a substantial target for EOR methods. To illustrate, an incremental recovery of just 2%—equivalent to 25% of primary recovery—would yield an additional 1–1.5 billion barrels of oil. Although steam injection has proved highly effective in many heavy oil reservoirs, over 95% of the Lloydminster resource occurs in formations less than 10 m thick, where excessive heat losses to adjacent strata render steam-based methods impractical. In contrast, EOR processes requiring only mild heating, or no heating at all, can be viable in such thinner reservoirs. Two mild heating techniques have already been tested in the field: the horizontal well hot oil circulation and hot water vapour technique. Martinez et al. (2017) developed several compositional models at the laboratory scale to evaluate the CSI schemes. Their approach provides a practical framework for scaling

solvent transport mechanisms from laboratory observations to field-scale applications, enabling more reliable assessments of solvent behaviour in post-CHOPS settings. This work represents an initial step toward establishing a systematic workflow for modelling solvent processes within wormhole networks operating across multiple scales. When the injected solvent was purified and pre-heated, heavy oil recovery improved as a result of increasing in heat and mass transfer, along with in situ de-asphalting caused by asphaltene precipitation. The N-Solv process, under these conditions, was estimated to deliver production rates more than fifteen times higher than those observed with conventional VAPEX. Beyond increasing output, the N-Solv technique also shows potential for upgrading oil quality, reducing energy requirements, and lowering global greenhouse gas emissions. However, since these outcomes were achieved from laboratory studies, the numerical forecasts carry inherent uncertainty and may lack full accuracy (Rezaei et al., 2010). Field-scale trials are therefore essential to validate the process and confirm its applicability under real reservoir conditions. Zhang et al. (2014) carried out six CSI experiments using three physical models of varying scales. Through numerical simulations, they examined key sources of uncertainty in upscaling the CSI technique, including capillary pressure, multi-phase relative permeability curves, rates of reactions in the model, and dispersion coefficients. Their results suggest that conducting simulations on physical models at multiple scales can significantly reduce the uncertainty in forecasting CSI performance at the field-scale.

Consequently, during the post CHOPS methods, the most important mechanism leading to increase oil rates is oil viscosity reduction. However, based on the post CHOPS methods, there are lots of technical challenging such as; reservoir heterogeneity, number of cycles, soak time, solvent/steam loading, and comingled or slug injection strategies. These are key parameters in this process and should be evaluated in physical and numerical models before testing the post CHOPS in the field scale. Furthermore, Table 1 summarizes the post CHOPS researches which have been performed in the field scale in Canada and USA.

4. Petrophysical and geomechanical properties

CHOPS serves as a primary recovery technique for heavy crude oil, with reservoir properties playing a crucial role in determining its effectiveness. Nevertheless, identifying the most influential reservoir parameters and quantifying their relationship with production performance remains a significant challenge (Cai et al., 2014). Typical CHOPS reservoirs extend over areas of approximately one kilometre in width and vary in thickness from 3 to 5 m sand layers to thirty-five meters sand intervals. They are characterised by permeabilities ranging from 0.5 to 5 Darcy, porosities of 28–32%, and average fluid saturations of about 88% oil and 12% water (Naderi et al., 2015). Canadian unconsolidated heavy oil reservoirs are generally 3–35 m thick, having porosity of 28–32% and permeability of 0.5–15 D. A typical CHOPS stratus is 10 m thick, oil saturation of 88%, water saturation of 12%, permeability of 2 D with a depth of 400 m and pressure of 3 MPa (Dusseault, 2007). Table 2 outlines the reservoir characteristics of a standard CHOPS well, and Table 3 provides its geometric and geomechanical parameters. In this representative case study, the reservoir was simulated as a three-layer system under isotropic horizontal stress conditions (Arbelaez, 2023).

CHOPS method has been successfully performed in more Canadian heavy oil fields to produce from unconsolidated sandstones (Oil viscosity typically ranges from 500 to 10,000 cP, with reservoir depths of 400–900 m, temperatures of 15–33 °C, and formation thicknesses between 4 and 25 m; the porosity is around 0.30 and the oil saturation is approximately 0.85, with neither a free water leg nor a significant gas cap usually present) (Walin et al., 2000). The mean characteristics of unconsolidated sandstone reservoirs were presented in Table 4 (Dusseault et al., 2002).

Also, typical Canadian CHOPS reservoir properties are provided in Table 5 (Anderson et al., 2019).

Table 6 presents another production profile representative of a CHOPS reservoir in the of the heavy-oil belt of Western Canada. The data that were taken from the field indicate that the rates of production increase and reach a peak in tandem with rising sand production. After several years, water production begins to rise and eventually surpasses oil output, marking the point at which the process is no longer economically viable. The co-production of sand leads to the development of wormholes within the porous media, creating significant pressure drops along their lengths (Sharifi et al., 2015).

5. Theory and mechanisms

The efficiency of CHOPS is largely governed by two key mechanisms: the wormholes generation and the flow behaviour of foamy oil (Xiao et al., 2012). Experiences in the field operations, tracer tests, as well as laboratory inquiries have persistently shown that there is a strong relationship between the pace of oil production and sand co-production. The boom in oil production can be greatly attributed to the fact that a highly conductive system of wormholes has been developed in the reservoir (Smith, 1988; Metwally et al., 1995). Wormholes are created in the heavy oil reservoirs where the sand production is permitted. These structures are created within a short period of time and may have a length of up to hundreds of meters (Sawatzky et al., 2002). The wormholes form an unbalanced area around the well which might even be felt in seismic (Lines et al., 2007). Wormhole initiation and propagation are regarded as important processes of improving oil recovery (Chugh et al., 1997). To sustain the growth of wormholes, there are two following conditions: the grains of sand can only be carried away when the pressure gradient at the tip of the wormhole is high enough, and can only be pumped to the wellbore when the pressure drop along the wormhole is also high (Tremblay, 2005). The other notable recovery mechanism associated with solution-gas drive is the non-Darcy two-phase flow that is denoted as foamy oil. The term was coined when field operators noticed that the produced fluids tended to form a stable foam of oil-continuous foam of the customary viscosity that was unusually high (Maini, 2001). As the pressure in the reservoir decreases lower than the saturation pressure, the dissolved gas starts to exsolve in the crude oil. Due to the unprecedented viscosity and molecular weight of the heavy oil, however, the gas does not instantly form a continuous phase but rather it is suspended as numerous small bubbles over some time (Sheng et al., 1999; Lilloco et al., 2001; Uddin, 2005). These entrained bubbles offer an additional driving force and also decrease the effective viscosity of the oil, which increases the mobility of the oil (Maini, 1996; Sheng et al., 1999). Wormhole formation and foamy oil flow may affect the pressure behaviour of CHOPS wells at the same time (Xiao et al., 2013). Overall, CHOPS is caused by two mechanisms that are interconnected, foamy oil flow and sand failure followed by sand production. Sand production is the initiation of a change in the formation stresses of pore-pressure, which causes shear or tensile failure.

This kind of failure creates areas of greater permeability, which boost oil production in CHOPS wells. Simultaneously, foamy oil behaviour reduces the in situ viscosity of the crude, and increases the apparent critical gas saturation, as gas bubbles are trapped in the viscous phase. The overall effect of these mechanisms explains the enhanced recovery normally realized in CHOPS reservoirs.

6. Technical, economic and practical challenges

There are a number of challenges that are linked to CHOPS production. Most notable among them is the extremely high viscosity of cold heavy oil to the point of being over a hundred thousand cPs. Although the improvements in downhole PCPs, rod strings, wellheads, and power units have been significant within the last two decades, they have not been enough to generate oils with viscosities of one hundred thousand cPs and above since the drag caused by the fluids in the production tubing becomes too high (Minish et al., 2012). The slurry stream

Table 1

The post CHOPS methods which have been performed in the field scale in Canada and USA.

Num.	Author	Year	Field Location	Title	Conclusions
1)	Miller K.A.,	2006	Alberta and Saskatchewan, Canada	Improving the state of the art of Western Canadian heavy oil water flooding technology	Western Canadian heavy oil waterfloods all exhibit very poor sweep efficiency due to a very adverse mobility ratio, initial reservoir heterogeneity and low profit margin-related erratic operating histories. The pressure-cycling process can create a favorable condition for recharged gas to contact the remaining oil in the reservoir.
2)	Dong et al.,	2006	Saskatchewan, Canada	Methane pressure-cycling process with horizontal wells for thin heavy-oil reservoirs	Oil recovery from CSI is mostly limited to high permeability regions created during CHOPS. Since it appears that production decline from a steam-soaked well is harmonic, the initial production data from a well may be extrapolated in this manner to obtain additional reservoir information.
3)	Chang et al.,	2012	Lloydminster, Alberta, Canada	Field scale simulation of cyclic solvent injection (CSI)	The model allows calculation of injection parameters and production rate from very viscous oil, pressure depleted, gravity drainage reservoirs.
4)	Seba et al.,	1969	Yorba Linda, California, USA	A mathematical Model of Repeated Steam Soaks of Thick Gravity Drainage Reservoirs	The predicted response of the reservoir to steam injection by both the analytical and numerical models is similar.
5)	Jones et al.,	1977	Midway Sunset, Western Kern County, California, USA	Cyclic Steam Reservoir Model for Viscous Oil, Pressure Depleted, Gravity Drainage Reservoirs	The importance of accurate field data, especially relative permeability data, to steam stimulation modeling cannot be overemphasized.
6)	Gontijo et al.,	1984	Midway Sunset, Western Kern County, California, USA	A Simple Analytical Model for Simulating Heavy Oil Recovery by Cyclic Steam in Pressure Depleted Reservoirs	The main features that make the model different from others are oil and water saturation which is based on a material balance and oil flow which can be into or out of the heated zone.
7)	Sylvester et al.,	1988	Midway Sunset, Western Kern County, California, USA	An Improved Cyclic Steam Stimulation Model for Pressure-depleted Reservoirs	Ultimate oil recovery by CSS in terms of the oil in place could be in excess of 20% or could be much lower.
8)	Gozde S. et al.	1989	Huntington Beach and Midway Sunset, California, USA	An Analytical Cyclic Steam Stimulation Model for Heavy Oil Reservoirs	The rate of drainage of heavy oil to a horizontal well calculated to be of the order of 0.16 m ³ /d per meter (0.3 barrels per day per foot) of well.
9)	Farouq S. M.,	1994	Cold Lake, Alberta, Canada	CSS-Canada's super strategy for oil sands	A mixture of propane and butane is more effective than butane alone and works almost as well as propane in the Vapex process.
10)	Butler et al.,	1981	Cold Lake, Alberta, Canada	Theoretical studies on the gravity drainage of heavy oil during in-situ steam heating	ECSP improves the performance of CSP at relatively low-to-intermediate pressures (below 600 psig) and utilizes the viscosity reduction and gas drive mechanisms during the early production.
11)	Butler et al.,	2000	Atlee-Buffalo, Alberta, Canada	Improved Recovery of Heavy Oil by Vapex with Widely Spaced Horizontal Injectors and Producers	At low permeabilities, the drainage rate is a linear function of the square root of permeability and at high permeabilities, the drainage rate is non-linear.
12)	Jamaloei B.Y.,	2013	Brintnell, Alberta, Canada	Enhanced Cyclic Solvent Process (ECSP) for Thin Heavy Oil Reservoirs	Although there is enhancement in extraction rates in the porous media, rates are still proportional to the square roots of permeability.
13)	Butler et al.,	1989	Athabasca, Alberta, Canada	Solvent Analog Model Steam-assisted Drainage	It appears that incorporation of dispersion effects into mass transfer models of the VAPEX process reduces the discrepancy between the experimental results and analytical models at identical values of Peclet number.
14)	Das et al.,	1998	Peace River and Athabasca and Cold Lake, Alberta and Tangleflags, Saskatchewan, Canada	Mechanism of the Vapor Extraction Process for Heavy Oil and Bitumen	The dependence of the stabilized oil rate on the square root of permeability has been confirmed.
15)	Boustani et al.,	2001	Athabasca and Panny and Dover, Alberta, Canada	The Role of Diffusion and Convective Dispersion in Vapour Extraction Process	The corresponding dispersion of butane in Cold Lake bitumen was found to be four orders of magnitude higher than previously reported molecular diffusion of butane in heavy oil and bitumen.
16)	Yazdani et al.,	2005	Fort McMurray, Alberta, Canada	Effect of Drainage Height and Grain Size on Production Rates in the VAPEX Process: Experimental Study	Based on the correlation for solvent based gravity drainage, the key requirement to achieve commercial extraction rates in Athabasca is to supply heat with the solvent. The correlation predicts an oil production rate for VAPEX in Athabasca of 8m ³ /day and an oil production rate for N-Solv of 140m ³ /day at 40°C and 400m ³ /day at 60°C.
17)	Kapadia et al.,	2006	Cold Lake, Alberta, Canada	Determination of Gas Dispersion in Vapor Extraction of Heavy Oil and Bitumen	The use of hot fluids as well as solvent-aided process would be effective in increasing oil recovery from non-wormhole domain, but at the expenses associated with solvent cost.
18)	Nenniger et al.,	2008	Athabasca, Canada	How fast is Solvent Based Gravity Drainage?	Warm VAPEX experiments using superheated pentane show promising production rates when compared to conventional VAPEX.
19)	Rangriz et al.,	2016	Alberta, Canada	Field scale modeling of CHOPS and solvent/thermal based post CHOPS EOR applications considering non-equilibrium foamy oil behavior and realistic representation of wormholes	Ethane is an effective solvent in producing Cold Lake bitumen and that the cyclic VAPEX process has the potential to be a breakthrough recovery technology.
20)	James et al.,	2007	Alberta and Saskatchewan, Canada	VAPEX, warm VAPEX, and hybrid VAPEX– The state of enhanced oil recovery for in situ heavy oils in Canada	
21)	Jha et al.,	1995	Cold Lake, Alberta, Canada	Vapour extraction (VAPEX) process for recovery of heavy oil and bitumen	

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Table 1 (continued)

Num.	Author	Year	Field Location	Title	Conclusions
22)	Qazvini et al.,	2012	Saskatchewan, Canada	Feasibility Study of Solvent-Based Huff-n-Puff Method (Cyclic Solvent Injection) To Enhance Heavy Oil Recovery	At the same operating conditions, the CO ₂ huff-n-puff process is more efficient than the CH ₄ based process (the RF is more than 70%).
23)	Li et al.,	2012	Lloydminster, Saskatchewan, Canada	Phase behavior of C ₃ H ₈ -n-C ₄ H ₁₀ -heavy oil systems at high pressures and elevated temperatures	The measured saturation pressure increases with temperature for a given system, while swelling factor maintains almost constant in a wide temperature range.
24)	Li et al.,	2013	Lloydminster, Saskatchewan, Canada	Enhanced swelling effect and viscosity reduction of solvent(s)/CO ₂ / heavy-oil systems	A significantly increased swelling effect of heavy oil can be obtained by adding either C ₃ H ₈ or n-C ₄ H ₁₀ into the CO ₂ stream. An enhanced viscosity reduction of the CO ₂ /heavy-oil system can be also achieved in the presence of either C ₃ H ₈ or n-C ₄ H ₁₀ .
25)	Sharifi et al.,	2017	Cold Lake, Alberta, Canada	CO ₂ -based heavy oil recovery processes for post-CHOPS reservoirs	CO ₂ yields a reduction of heavy oil viscosity and oil swelling within the reservoir. The incremental recovery factor at the end of four years of operation is 2.4%.
26)	Krumrine et al.,	2014	Lloydminster, Alberta and Saskatchewan, Canada	Investigation of Post CHOPS Enhanced Oil Recovery of Alkali Metal Silicide Technology	Silicide reacts with formation water to create insitu hydrogen gas, alkali silicate and heat to promote improved recovery. Silicide modeling shows that increase production can be expected for an additional 5–10 years, adding 25–50% to recoverable reserves.
27)	Mathur et al.,	2017	Ugnu, Alaska, USA	Life After CHOPS: Alaskan Heavy Oil Perspective	Oil recovery factor and sweep efficiency can be increased by combining the conventional water flood EOR with polymer injection.
28)	Anderson et al.,	2019	Manatokan East near Bonnyville, Alberta, Canada	Solvent Screening Study for a Post CHOPS Cyclic Solvent Injection Pilot	Ethane CSI should perform better than methane and propane CSI, but there were economical hurdles. Based on the commercial availability of methane and propane, it is recommended for the post CHOPS field pilot in advance of the coreflood results.
29)	Coskuner et al.,	2020	Lloydminster, Alberta and Saskatchewan, Canada	Enhanced Oil Recovery in Post-CHOPS Cold Heavy Oil Production with Sand Heavy Oil Reservoirs of Alberta and Saskatchewan Part 1: Field Piloting of Mild Heating Technologies	The combination of polymer flooding with horizontal wells and EOR processes involving mild heating (for example Hot Water Vapour Process) can yield additional viscous oil recovery.
30)	Martinez et al.,	2017	Orinoco, Venezuela and Lloydminster, Canada	A Practical Approach for Scale-Up of Solvent Transport Mechanisms in Post-CHOPS EOR Applications	Considering identical surface solvent injection rate, effective dispersivity would enhance oil production and reduce gas production due to an increase in mixing between solvent and oil.
31)	Rezaei et al.,	2010	Cold Lake and Lloydminster, Canada	Improving the performance of vapour extraction of heavy oil and bitumen using the warm VAPEX process	The live and dead oil production rates were both improved by superheating the hydrocarbon solvent during the warm VAPEX process. Cold Lake bitumen benefited more from the warm VAPEX process than the Lloydminster heavy oil.
32)	Zhang et al.,	2014	Alberta and Saskatchewan, Canada	Upscaling Study of Cyclic Solvent Injection Process for Post-CHOPS Reservoirs through Numerical Simulation	Capillary pressure plays a critical role in matching the lab-scale CSI performance. However, the capillary pressure does not always play a positive role in terms of the recovery factor.

Table 2
Characteristics of a typical CHOPS reservoir.

Reservoir characteristics	Values
Wellbore radius (in)	2.5
Reservoir radius (ft)	100
Reservoir pressure (psi)	770
Temperature (°F)	150
API Gravity (° API)	15
Gas-specific gravity	0.7
Bubble point pressure (psi)	100
Oil saturation (%)	85
Water saturation (%)	15
Gas saturation (%)	0

is brought to the surface and then fed directly into separators with a capacity of about 100–150 m³ and kept at temperatures of 60–80 °C. In such circumstances, the sand and the oil are separated, the methane and the liquid are separated and the water and the oil are separated. The tanks are then emptied periodically to get rid of the accumulated liquids as well as the sand which accumulates at the base. The separated sand has been managed in a number of ways, which include washing, landfill disposal, storage in dissolved salt caverns, and road spreading or injection in slurry form (Walin et al., 2000). Advanced numerical modelling techniques have been employed to forecast when sand

Table 3
Geometry and geomechanical characteristics of a typical CHOPS reservoir.

Parameters	Layer 1	Layer 2	Layer 3
Depth (ft)	1680	1700	1720
Formation height (ft)	20	20	20
Porosity (%)	20	30	20
Horizontal permeability (mD)	50	1000	50
Vertical permeability (mD)	5	100	5
Vertical pressure gradient (psi/ft)	1	1	1
Maximum horizontal pressure gradient (psi/ft)	1	1	1
Minimum horizontal pressure gradient (psi/ft)	1	1	1
Young modulus (psi)	1.0E06	1.0E06	1.0E06
Poisson ratio (fraction)	0.30	0.25	0.30
Cohesion (psi)	1000	300	1000
Friction angle (°)	15	15	15
Dilation angle (°)	15	15	15

production is likely to begin during cold heavy oil recovery. However, most of these models have proved unreliable in estimating sand production dynamics or its relationship with oil output. Conventional reservoir simulators have also been adapted to model cold production with sand, but these typically lack the capability to incorporate the complicated processes that fails in unconsolidated zones (Rivero et al., 2010). Continuous sand production results in dynamic changes to

Table 4
Mean characteristics of unconsolidated sandstones.

Parameters	Range
Depth (ft)	1200 – 2800
Porosity (%)	28 – 32%
Permeability (D)	0.5 – 4.5
Oil Viscosity (cP)	500 – 15000
Oil Saturation	0.72 – 0.88
Gas Saturation (%)	0.0
Pore Pressure (psi)	378 – 1160
Grain size (μm)	120
Clay content (%)	< 5% in oil-saturated zone
Asphaltene content (%)	12% (11 °API) – 5% (17 °API)
Gas in solution	> 90% CH ₄ and < 10% CO ₂

Table 5
Typical Canadian CHOPS reservoir properties.

Parameters	Values
TVD Depth (m)	300–600
Pay Thickness (m)	2–15
Porosity (%)	30–35
Matrix Permeability (D)	1–5
Dead Oil Viscosity (cP)	1000–100000
Oil API (°)	8–20
Initial Oil Saturation (%)	60–90
Initial Reservoir Pressure (kPa)	2300–3500 (80% hydrostatic gradient)
Initial Reservoir Temperature	12–17 °C
Thief Zones	Variable bottom water and top gas
Ultimate Recovery Factor	1–15%
Sand Cut	0–30% Formation dependent
Water Cut	10–95%
Gas-Oil-Ratio	3–10 m ³ / m ³

Table 6
Properties of Cold-Lake CHOPS reservoir.

Properties	Values
Depth to reservoir top (m)	291
Net pay (m)	~6
Porosity (%)	6 – 40
Oil saturation (%)	40 – 80
Solution gas-to-oil ratio (m ³ /m ³)	10
Horizontal rock permeability kh (mD)	30–8500
kv/kh	0.8
Effective rock compressibility (1/kPa)	5 × 10 ⁶
Rock heat capacity (kJ/m ³ °C)	2600
Rock thermal conductivity (kJ/m day°C)	660
Reference pressure (kPa)	2500
Reference depth (m)	291
Initial reservoir temperature	20
Dead oil viscosity (cP) 20 °C	26000
Water thermal conductivity (kJ/m day°C)	53.4
Gas thermal conductivity (kJ/m day°C)	5
Oil thermal conductivity (kJ/m day°C)	11.5
Foamy-oil kinetic parameters	N ₁ = 1.441/day G ₁ = 0.1/day
K-values	Kv ₁ = 5.4547 × 10 ⁵ kPa
Wormhole radius (m)	0.075
Dilation critical velocity (m/day)	1.15 × 10 ^{−3}
Number of grid blocks	118 × 147 × 50 (vertical)
Dimensions of grid blocks (m)	20 × 20 × ~ 1 (vertical)

reservoir properties such as porosity, permeability, compressibility, and in situ stress conditions, which further complicates the modelling of post-CHOPS EOR applications. This underlines the necessity of dynamic geological models for simulation studies (Rangriz et al., 2013). Technical considerations also arise when CHOPS is transferred to fields worldwide, owing to site-specific geological and reservoir parameters 'variations. A major concern is whether the planned production rate will be sufficient to prevent sand accumulation in the wellbore. During

CHOPS completion design, it is critical to determine whether the anticipated production would be sufficient to lift sand to the surface. This issue is particularly acute in horizontal wells, where sand can amass around/in the wellbore and potentially cause well failure. A theoretic study of sand transportation in heavy-oil fields by Boyun et al., (2010) introduced the concept of a critical rate of production, defining the rate necessary to lift sand in wells with different directions from vertical to horizontal. The growth of complicated, non-homogeneous, highly permeable channels (wormholes) during CHOPS adds another layer of complexity to process analysis and scalability. One of the major challenges lies in accurately estimating wormhole growth dynamics. Existing models generally provide simplified representations of wormhole networks, often reducing them to extended wellbores. Although wormhole propagation caused by sand failure is widely believed to follow fractal behaviour, there is still no established workflow for integrating geomechanical constraints into the generation of these fractal patterns (Yu et al., 2019).

A post-CHOPS reservoir is complicated to exploit with EOR due to the presence of wormholes, which create a dual permeability system. Any injected material will disperse through the wormhole network, which is mostly swept of oil, and won't interact significantly with the residual oil in the lower permeability reservoir matrix. Most CHOPS wells are also produced down to atmospheric pressure, leaving the reservoir with no pressure drive or solution-gas drive (Anderson et al., 2019). The presence of wormholes in the reservoir must be accounted for when designing post-CHOPS recovery processes. A central concern is how stable those high permeable channels are throughout the re-pressurisation operations. Wormholes may remain open as stable, high-permeability channels that facilitate fluid injection, or alternatively collapse to improve conformance for injected fluids (Oldakowski et al., 2018). Beyond wormhole stability, two of the principal challenges associated with CHOPS as a primary recovery method are its limited recovery efficiency and its environmental footprint. Oil recovery is typically restricted to a maximum of 15%, constrained by the high costs of production, sand handling and by production interruptions caused by sand-related workovers. The environmental impact of CHOPS is considerable, arising from disturbance of the surface because of short spacing of wells, emissions and fluid treatment, and the long-standing clearance of produced sand. Simulation studies have shown that the super sump system could offer substantial improvements over conventional CHOPS operations. Reported benefits include recovery factors 50% larger, operational costs reduced by 30%, energy-efficiency improved by 75%, and emissions lowered by 95%. Cost estimates further suggest highly favourable economics relative to standard CHOPS processes (Arnold et al., 2012). Therefore, CHOPS relies on sand influx for increased production, but excessive sand can damage equipment, reduce wellbore stability, and require costly surface handling. The sand production process should be closely monitored and may involve special methods such as sand screens, gravel packs or downhole sand separation. Another phenomenon that gives rise to a complex multi-phase flow system is the foamy oil phenomenon, in which gas bubbles are suspended in the heavy oil. This behavior is frequently difficult to model in traditional reservoir simulation models and predict and maximize production. Furthermore, CHOPS wells have been found to be an important source of methane, due both to vented gas and fugitive leaks. It is very important that these emissions are properly measured and minimized in order to ensure environmental sustainability. Also, high sand cuts and artificial lift (e.g., PCPs) may pose operational issues associated with wear and tear of pumps, torque demand, and fluids. The government of Alberta requires improved downhole instrumentation e.g. densimeter to monitor and manage these conditions better. Moreover, it may not be easy to make away with the mass of generated sand on the surface, and it will be necessary to use special separation and disposal techniques. The conventional approaches are transporting sand to the dumping areas by means of trucks, which may be expensive and hazardous to the environment. Other firms are looking into other options such as salt cavern

in-situ disposal. Lastly, geomechanical activity of the reservoir such as wormhole proliferation and alteration of rock characteristics are vital factors that should be understood to maximize production. New simulation techniques are being developed to model these complex phenomena.

7. CHOPS process, experimental works

Laboratory investigations show that high-permeability channels tend to remain as stable conduits during the course of CHOPS operations. Oldakowski et al. (2018) investigated wormhole stability by exposing the system to potentially disruptive conditions, namely cold- and hot-water circulation, heating, and pressurisation using hydrocarbon gases including methane and ethane. These experiments were carried out in a triaxial cell roughly 19 centimetres wide and 18 centimetres high, filled with water-wet sand saturated with heavy oil (Fig. 4). In this setup, wormholes were initiated by injecting dead oil at a satisfactorily acceptable rate to trigger sand production, after which different destabilising conditions were introduced to examine their effects. Passing cold water through the wormhole caused gradual erosion of its walls, which in time resulted in the collapse of the sand pack after over a week. When hot water was used, this erosion progressed at a much faster rate. Heating alone did not lead to the collapse of the pack, although it did weaken the wormhole walls, leading to an increase in diameter of more than twice the original size. The reduction in heavy oil viscosity under heating conditions also lowered the apparent strength of the surrounding sand. In experiments involving methane, pressurisation followed by controlled depressurisation left wormholes stable. By contrast, when ethane was injected under pressure, the adjacent sand matrix collapsed within two weeks. As with the heating scenario, the dissolution of ethane into the heavy oil reduced viscosity and weakened the sand, ultimately destabilising the wormhole. These observations highlight that wormhole stability is strongly influenced by both thermal and solvent-related effects, with important implications for post-CHOPS recovery strategies.

Ma et al. (2018a) examined the combined application of CO₂-cyclic solvent injection (CSI) with gas flooding (GF) and compared its performance against CO₂-CSI with water flooding (WF). Ten sand-pack laboratory experiments were carried out to evaluate and compare the recovery achieved through WF, CO₂-CSI, and the combined CO₂-CSI with gas or water flooding following primary production. Results indicated that the optimum injection strategy for maximising heavy oil recovery was to introduce CO₂ and water immediately after each CSI production cycle. Moreover, the CSI + GF process achieved its highest recovery factor at a moderate CO₂ injection rate. Taken together, the combined CO₂-CSI and GF/WF method appeared to be a promising option for recovering the remaining oil in post-CHOPS reservoirs. Fig. 5 illustrates the experimental setup employed for primary production, WF, CO₂-CSI, and the combined CO₂-CSI with GF/WF.

Narayan et al., (2016) developed an experimental CHOPS apparatus to investigate how rock compressive strength and flow-related parameters, such as oil viscosity, net and total confining pressure, and injection rate, affect core permeability. The laboratory apparatus developed at the University of Alaska Fairbanks is shown in Fig. 6, while a schematic representation is provided in Fig. 7. Results indicated that, at a fixed pressure across all rates, 99.8% of the variance in permeability at lower pore volumes injected could be attributed to viscosity of oil, the rate of injection, and their interaction. Once the injected pore volumes were increased, these variables and their interaction accounted for only 40.63% of the variance in permeability.

Chemical flooding such as alkaline-surfactant and polymer (ASP) could be a proper way to target CHOPS reserves. Laboratory experiment by Mai et al. (2009) presented that alkaline-surfactant (AS) flooding could be a viable method to increase oil recovery at the conclusion of water flooding. Also in another work ASP flood was tested by Bryan et al. (2013) showing that addition of AS to polymer can lead to a more

efficient oil recovery compared to polymer alone. Alshmakhy et al. (2009); (2012) performed sand pack experiments to evaluate the effect of foaminess of the oil on the performance of solution gas drive. They picked a fluorinated hydrocarbon type surfactant (foaming agent) with high foam stability after mixed with the oil and ran depletion tests to conclude that foaminess had a key role in solution gas drive performance only at low rates of depletion and surfactant reduced gas mobility as it increased foaming which resulted in lower gas oil ratio. Du et al., (2013) experimentally examined how wormhole characteristics and sand-pack model properties influence CSI performance by using three different cylindrical sand-pack models (Fig. 8). In this study, propane was used as the solvent. The outcomes indicated that CSI performance improves with greater wormhole coverage. In addition, wells exhibiting horizontal wormholes tended to demonstrate superior CSI performance. The experimental setup is illustrated in Fig. 9.

However, the screening of the CHOPS and post-CHOPS process in laboratory scale can decrease the technical challenges and make better decisions to improve field scale recovery.

In summary, laboratory studies on CHOPS have mainly focused on investigating wormhole stability, multiphase flow behaviour, and the evaluation of post-CHOPS recovery methods. Also, several experimental setups containing heavy oil-saturated sand to examine the effects of thermal conditions, water circulation, and hydrocarbon gas injection on wormhole stability were conducted. In addition, sand-pack experiments have been conducted to evaluate CO₂ cyclic solvent injection (CSI) combined with gas/water flooding, the influence of mechanical and flow parameters on permeability evolution, and the performance of chemical recovery methods such as alkaline-surfactant (AS) and alkaline-surfactant-polymer (ASP) flooding. Other experimental investigations using sand-pack models and solvents such as propane have focused on the effects of wormhole characteristics and reservoir properties on CSI performance. Overall, these laboratory investigations provide valuable insights into sand production mechanisms, wormhole behaviour, foamy oil flow, and the screening of post-CHOPS recovery techniques for improving field-scale recovery.

Although laboratory studies have significantly improved the understanding of CHOPS mechanisms and post-CHOPS recovery processes, conflicting conclusions remain regarding the factors controlling wormhole stability and recovery performance. For example, wormhole stability is strongly affected by thermal and solvent-related effects. While heating and solvent injection can improve oil mobility by reducing viscosity, they may also weaken the surrounding sand structure and compromise wormhole integrity under certain conditions. Therefore, the impact of these processes depends strongly on reservoir properties, fluid characteristics, and operating conditions. Previous studies have also shown that no single post-CHOPS recovery method is universally superior. CO₂-based cyclic solvent injection, gas/water flooding, and chemical flooding methods such as AS and ASP have demonstrated potential for improving recovery; however, their effectiveness varies depending on wormhole characteristics, reservoir heterogeneity, and injection strategy. This highlights the need for selecting recovery methods based on reservoir-specific conditions rather than applying a general approach. Despite valuable laboratory findings, most published studies are limited by small-scale experimental setups, simplified reservoir conditions, and insufficient field-scale validation. The lack of comprehensive field data on sand production, wormhole evolution, and multiphase flow behaviour remains a major challenge for reliable modelling and optimization. Future studies should integrate laboratory experiments, advanced numerical simulations, and field monitoring to better evaluate CHOPS improvement strategies and reduce uncertainties in recovery predictions.

8. CHOPS process, modelling, simulation and optimisation works

Shao et al. (2002) proposed an elastoplastic damage model to

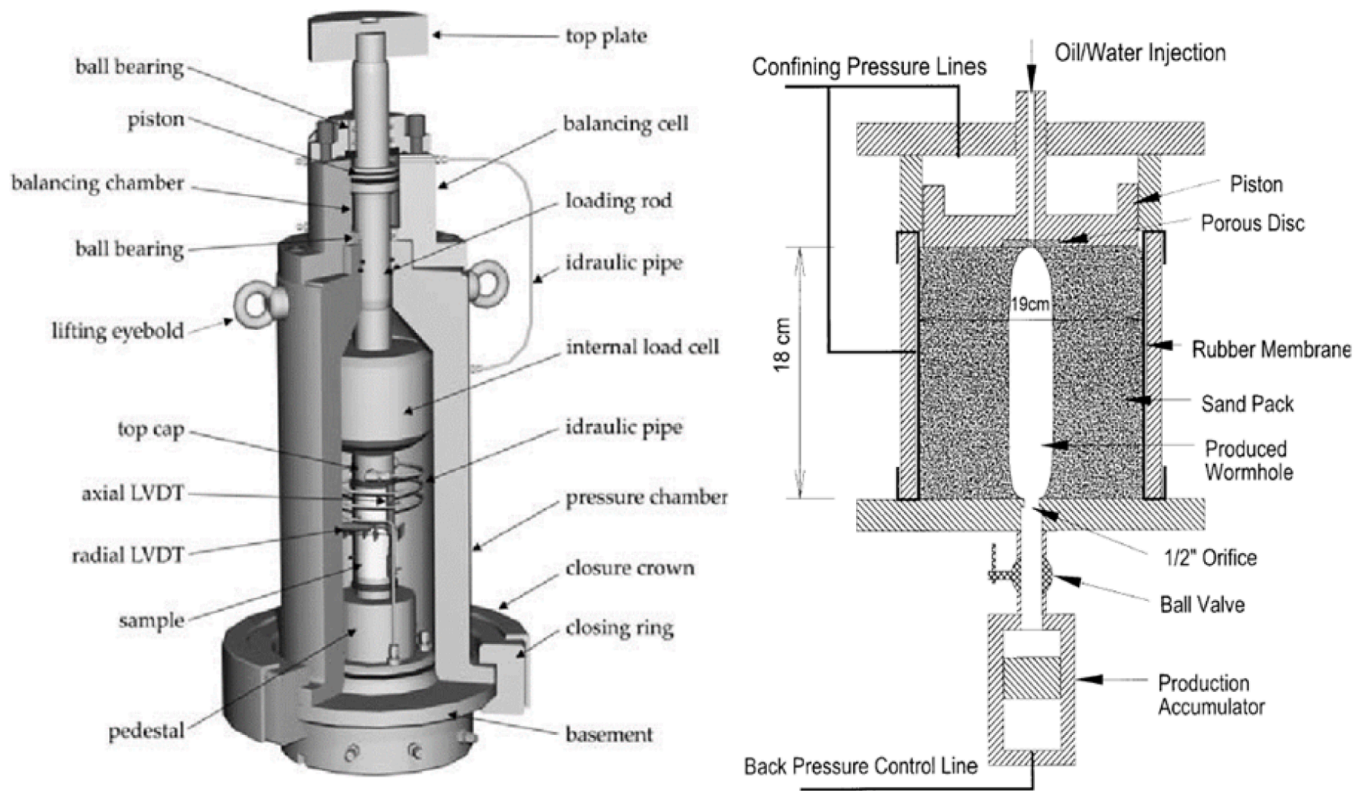


Fig. 4. Schematic of triaxial cell for testing the wormholes stability (Oldakowski et al., 2018).

describe sand production associated with rock dilation and the onset of wormhole formation. In their constitutive approach, the mechanical behaviour of sands was represented using the Drucker-Prager failure criterion.¹ Expanding on this type of modelling, Yu et al. (2020) constructed a computational mesh based on a fractal pattern generated through diffusion-limited aggregation (DLA), with finer grid resolution in regions where wormholes were present (Figs. 10 and 11). They proposed a new computational scheme that links compositional flow simulation with sand fluidisation and production, incorporating a sand-arch stability criterion² at the wormhole tip. According to this approach, wormholes continue to propagate along the fractal pathway whenever the pressure gradient at the tip surpasses the threshold required for sand-arch stability. To simulate CHOPS behaviour, they designed and implemented a workflow that combines compositional flow modelling with sand-arch failure and fluidisation, both controlled by the stability criterion and the assumed fractal growth pattern. Porosity was updated progressively in accordance with the sand fluidisation process. These procedures were implemented in MATLABVR (The MathWorks, Inc., Natick, Massachusetts, USA) and coupled with the Computer Modeling Group numerical reservoir simulator (version 2017). Dynamic wormhole growth was regulated by applying the sand-arch stability criterion to determine whether an existing wormhole should continue to extend along the designated statistical fractal pathway.

Shikai et al. (2023) combined a modified PGB sand failure criterion³ with models for foamy oil behaviour, relative permeability, and a normalised damped-IEnKF framework to create an ensemble-based simulation for analysing wormhole initiation and propagation. The approach was conditioned on production data for the stream including oil, associated gas, water, and produced sand. A code in MATLAB was developed

to simulate sand failure by linking it to the CMG modelling package, where foamy oil dynamics were standardised using two chemical reactions. To enhance accuracy while keeping computational demands manageable, the calibration of sand failure was performed at shorter time steps than those adopted for the data assimilation process. This integration highlights the value of combining geomechanical modelling with ensemble-based data assimilation to improve prediction and optimisation of CHOPS performance. The integrated workflow, incorporating the damped-IEnKF algorithm, is shown in Fig. 12 and proceeds through four main stages:

1-Initialisation – A set of PGB-CHOPS models is generated using initial estimates of the parameters to be evaluated.

2-Simulation – The CHOPS process is simulated for each model in the ensemble. Specifically, for each model:

- For each case, the simulator first extracts rock and fluid properties, including porosity, permeability, and pressure, for all grid blocks at each time interval.
- Next, the sand-failure norm is assessed using these extracted properties, and the volume of produced sand is determined for the grids that satisfy the failure criterion.
- The porosity is then updated on the basis of the calculated sand volume, after which permeability is recomputed using the Kozeny-Carman correlation.
- The new porosity and permeability are re-input into the simulator, which is then restarted and run to the next interval.

3-Data assimilation – When the pre-specified assimilation time is reached, model parameters are iteratively updated using the damped-IEnKF algorithm until sufficient accuracy is achieved. Each iteration contains a verification step in which Stage 2 is repeated from the initial time point.

4-Progression – The updated ensemble is moved forward to the next assimilation time point by repeating Stage 2.

¹ Appendix A (Section 1)

² Appendix A (Section 2)

³ Appendix A (Section 3)

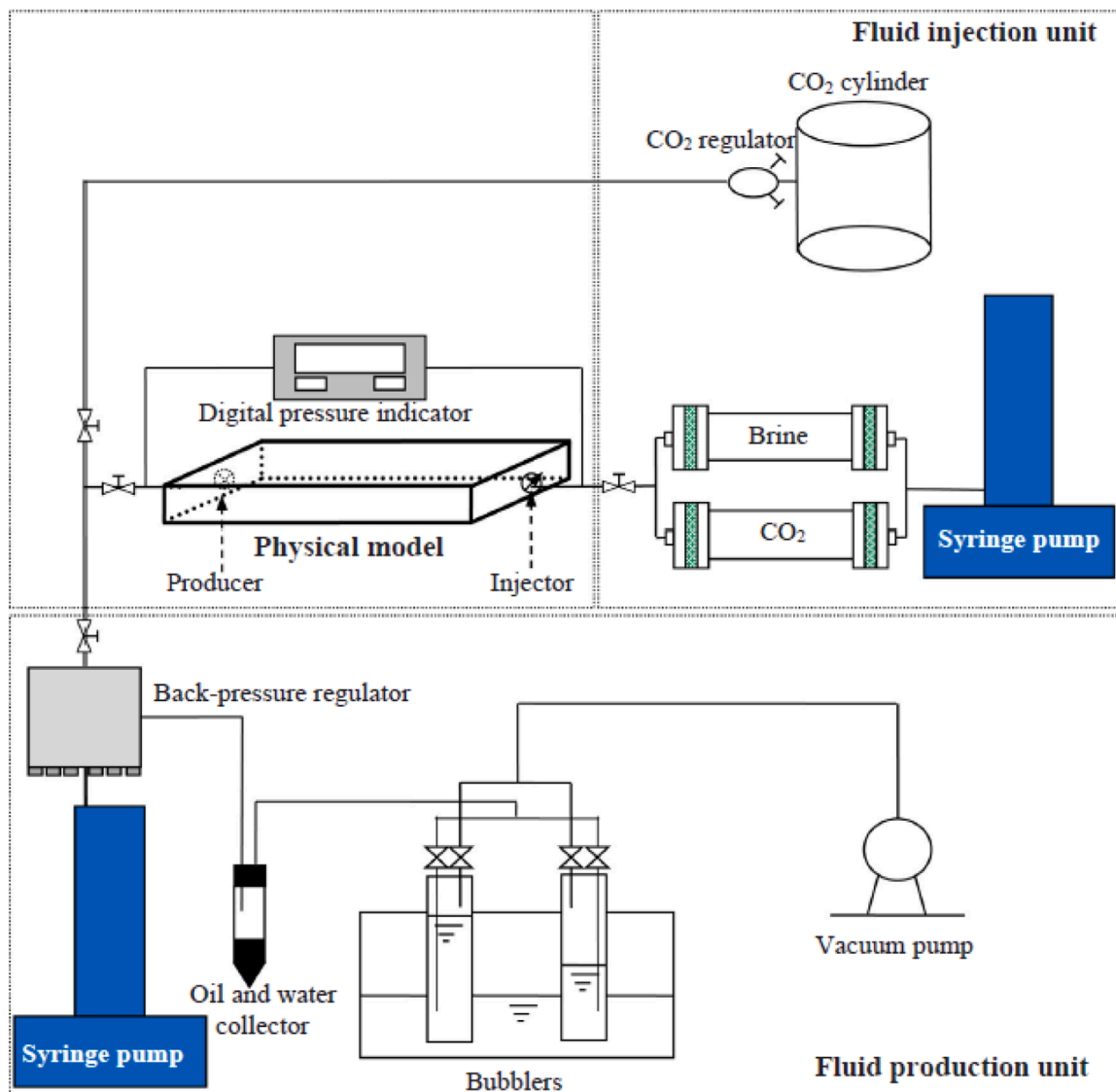


Fig. 5. Schematic diagram of the experimental set-up for conducting the primary production, subsequent CSI and/or water/gas flooding in Tests (Hongze and Gu, 2018).

Comparable ensemble-based diagnostics have been applied to post-fracture clean up in unconventional gas wells, where analysis of early-time flow back is used to infer relative permeability, fracture conductivity and storage effects. These studies provide a useful analogue for framing CHOPS data assimilation and parameter identifiability during transient clean up phases (Nasriani et al., 2018; Nasriani, Jamio-lahmady, 2019).

Aghabarati et al., (2008) integrated seismic interpretation with reservoir simulation to investigate CHOPS performance in a Saskatchewan heavy oil field, with the objective of gaining clearer insight into reservoir characteristics and recovery behaviour. Geostatistical methods were first employed to evaluate the porosity at the initial condition, using seismic. The Sand production was then modelled by an erosional velocity approach,⁴ with simulations run against oil production performance. Finally, simulated porosity results were compared with porosity estimates derived from a second seismic survey conducted in 2001, thereby providing a means to validate simulation outcomes with seismic data. Two principal mechanisms can lead to sand production: shear

failure and tensile failure. The study site, Plover Lake, lies within the Canadian heavy oil belt that spans Alberta and Saskatchewan, producing from the Devonian–Mississippian Bakken Formation. These laminations are associated with NE–SW trending shelf-sand tidal ridges, which could reach up to 30 m in thickness, 5 kilometres in width, and 50 kilometres in length. Before the setup of PCP pumps, well oil rates ranged from 1 to 5 m³/d, but increased three- to five-fold after PCP implementation. Cumulative sand production records indicate initial sand cuts of 30–60%, declining to around 5% as oil production rates dropped. A well was chosen for detailed modelling. The reservoir simulation was conducted using the QuikLook simulator, while depth conversion for the reservoir top and base was performed by means of the kriging with external drift geostatistical method. Two modelling cases were considered: one excluding sand production, and the other history-matched to production from the selected Well (Fig. 13). Their findings underscore the importance of understanding how high-permeability channels, or wormholes, affect sweep efficiency when assessing post-CHOPS improved oil recovery options such as VAPEX and thermal methods.

The validation of the new CHOPS simulator produced satisfactory results in both production and geomechanics when compared with commercial software packages (CMG and ABAQUS), with efforts made

⁴ Appendix A (Section 4)



Fig. 6. Laboratory set-up for CHOPS process (Narayan et al., 2016).



Fig. 8. Sand pack models (Du et al., 2013).

to align the models as closely as possible by running equivalent cases. The validation procedure incorporated a verification stage to confirm that boundary conditions were properly applied and that the main validation variables followed the expected trends. For the multiphase flow model, benchmarking was carried out against CMG, assessing production parameters such as pressure, saturation, flow rate, and cumulative output. Two reference cases were examined: a single-phase system involving oil and gas, and a two-phase system of oil and water. Notable differences between the simulators limited the extent of alignment. For example, CMG applies mean pressure rather than oil pressure, treats saturations differently (not as explicit variables), adopts different correlations for PVT properties, and uses distinct boundary conditions. The two-phase model yielded closer agreement between the simulators

than the one-phase case. Validation of the elastoplastic formulation was carried out using ABAQUS, covering both elastic and elastoplastic scenarios under isotropic as well as anisotropic horizontal stress regimes, and applied to models with single-layer and multi-layer configurations. Mechanical pertinent parameters including displacement, strain, and stress were compared, and the alignment was found to be strong, with boundary conditions well imposed and results deemed adequate across all variables. The coupled simulation was benchmarked against CMG, evaluating both elastic and elastoplastic responses under isotropic and anisotropic horizontal stress conditions, within a single-layer, two-phase oil–water framework. Production and mechanical variables were assessed, with results judged acceptable for pressure, adequate for saturation, and showing only minor differences in production and

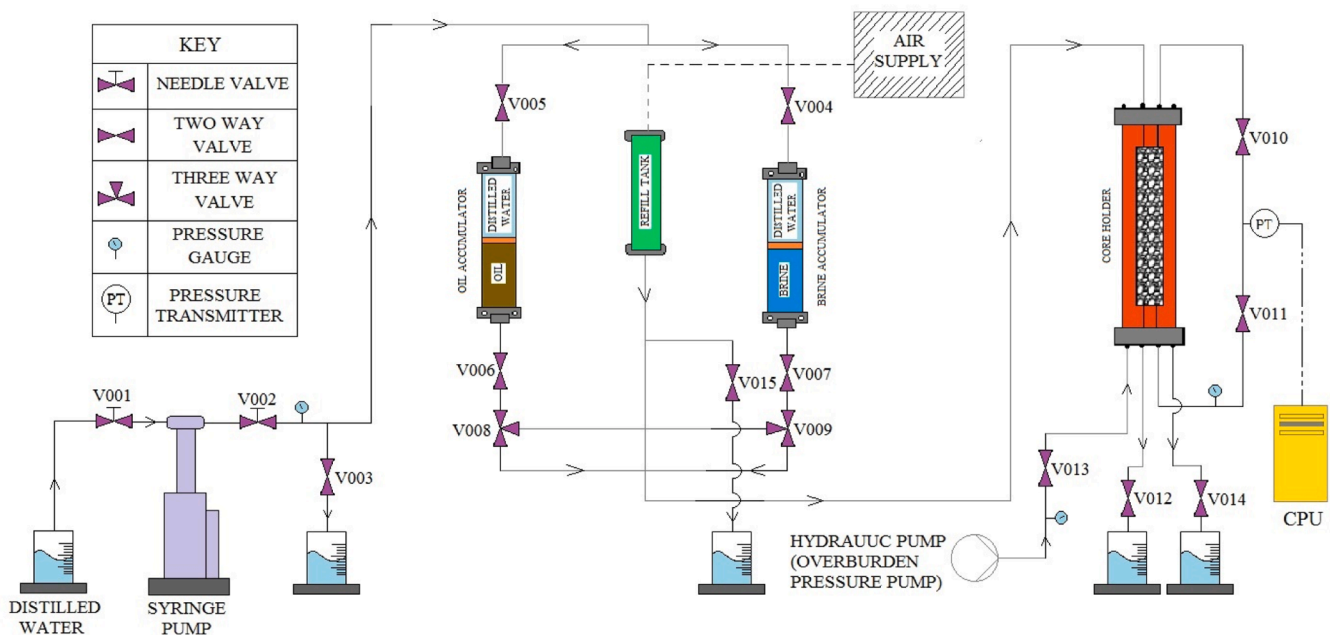


Fig. 7. Schematic of experimental set-up for CHOPS process (Narayan et al., 2016).

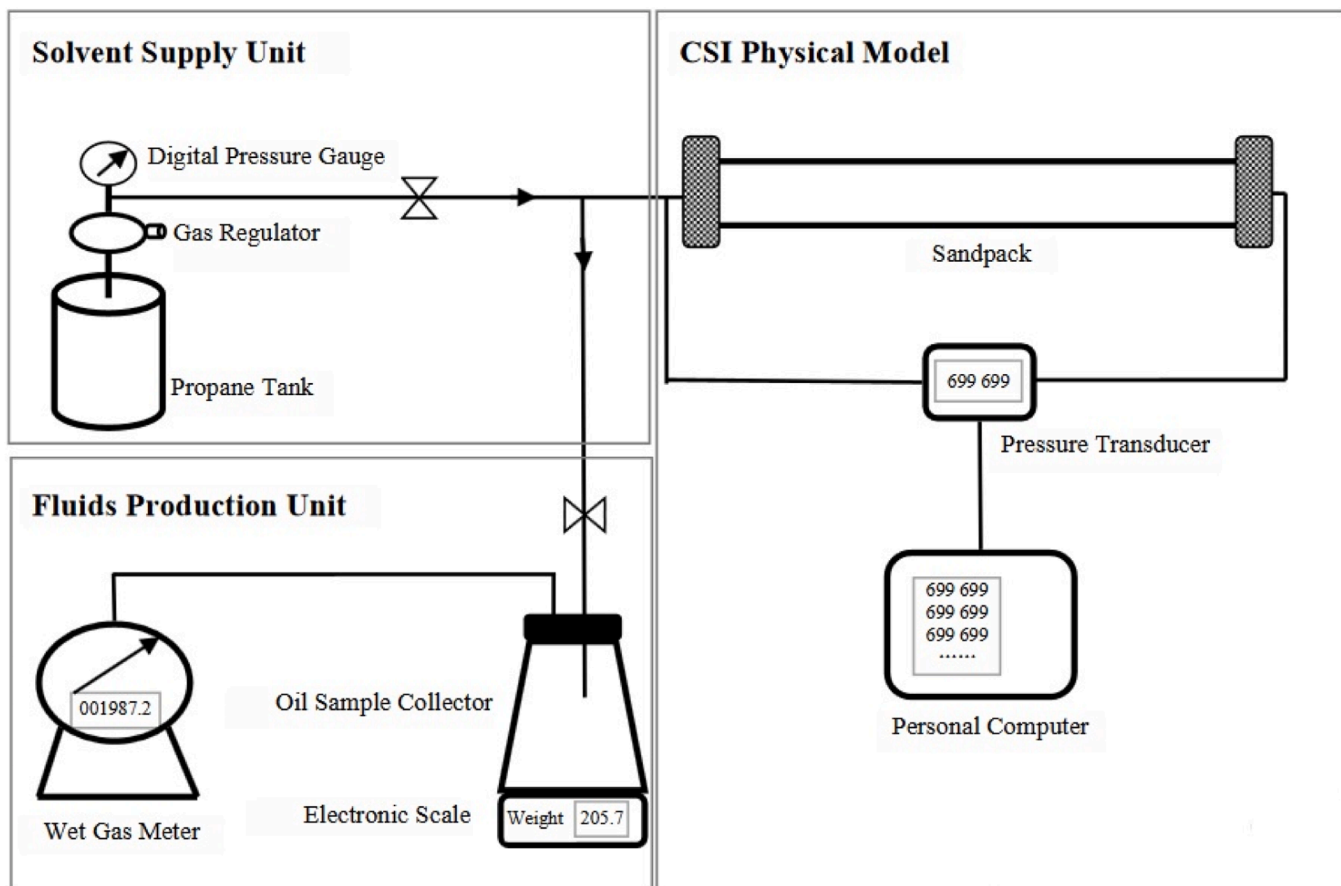


Fig. 9. Schematic of the experimental sand pack set-up (Du et al., 2013).

cumulative rates. Displacement, strain, and stress results were satisfactory, displaying correct trends and properly imposed boundary conditions. In elastoplastic cases, lower strain and stress values were observed, particularly in plastic strain. However, sand production could not be validated against CHOPS field data, as the simulations did not reproduce the typical levels of sand observed in practice (Arbelaez, 2023).

Rivero et al., (2010) developed a CHOPS model that linked a geomechanical modelling package (finite-element) with a reservoir simulation package (finite-difference). Within this setup, the geomechanical module accounted for sand failure and production, while stress variations were derived from the pressure field computed by the reservoir simulator. The resulting modifications in the reservoir pertinent parameters, such as porosity and permeability, were then transferred back into the reservoir simulator, where they were incorporated into the fluid flow calculations. As production advanced, wormholes were progressively generated, with individual wormholes extending further from producing wells. The standard black-oil PVT formulation, frequently employed in reservoir simulation, was found to be inadequate for representing foamy oil behaviour. To overcome this, the model incorporated a more advanced description of fluid properties based on kinetic reaction mechanisms.⁵ For validation, the approach was applied to a portion of a play operated by Husky Energy in the Lloydminster region of Saskatchewan, Canada. The model successfully matched fluid production rates in most wells and reproduced the production trends. A pressure versus sand rate relationship was first established to history-match a well and was then extended to forecast sand output in the remaining wells, achieving close agreement with observed data.

Despite this success, the methodology is constrained by its dependence on a correlation between porosity loss caused by sand failure and the associated permeability increase, a relationship that is problematic to quantify empirically and therefore must be adjusted as a parameter in history-match.

Vanderheyden et al. (2013) employed a Lagrangian–Eulerian approach to simulate multiphase flow systems where fluid–structure interactions are coupled with substantial deformation, material damage, and failure.⁶ Their model incorporated a generalised criteria in sand failure coupled with a pressure equation that was non-linear, in addition to equations for foamy oil and sand flow. The simulation results reproduced key characteristics of CHOPS production, including asymmetry and slugging behaviour. Istchenko et al. (2012) proposed using the history match results against field data to refine pertinent parameters, with the model subsequently applied to forecast production scenarios in CHOPS. Wang et al. (2001.) advanced an integrated methodology by coupling a 3-phase, 3D model with a geomechanics model,⁷ validated against field data of Frog Lake in Alberta. Their analysis compared initial production with no sand against production with sand production (CHOPS). They noted that while heating may provide a temporary boost in CHOPS well performance, conductive heat penetration is too slow to sustain viscosity reduction unless high-rate steam injection (fracturing) is employed. Moreover, thermal effects are unlikely to influence sand production or wormhole growth, as heat transfer cannot reach the distal wormhole tips where yielding occurs. Beyond production rate improvements, wormhole development in vertical wells was also associated with higher recovery factors compared with non-CHOPS horizontal

⁵ Appendix A (Section 5)

⁶ Appendix A (Section 6)

⁷ Appendix A (Section 7)

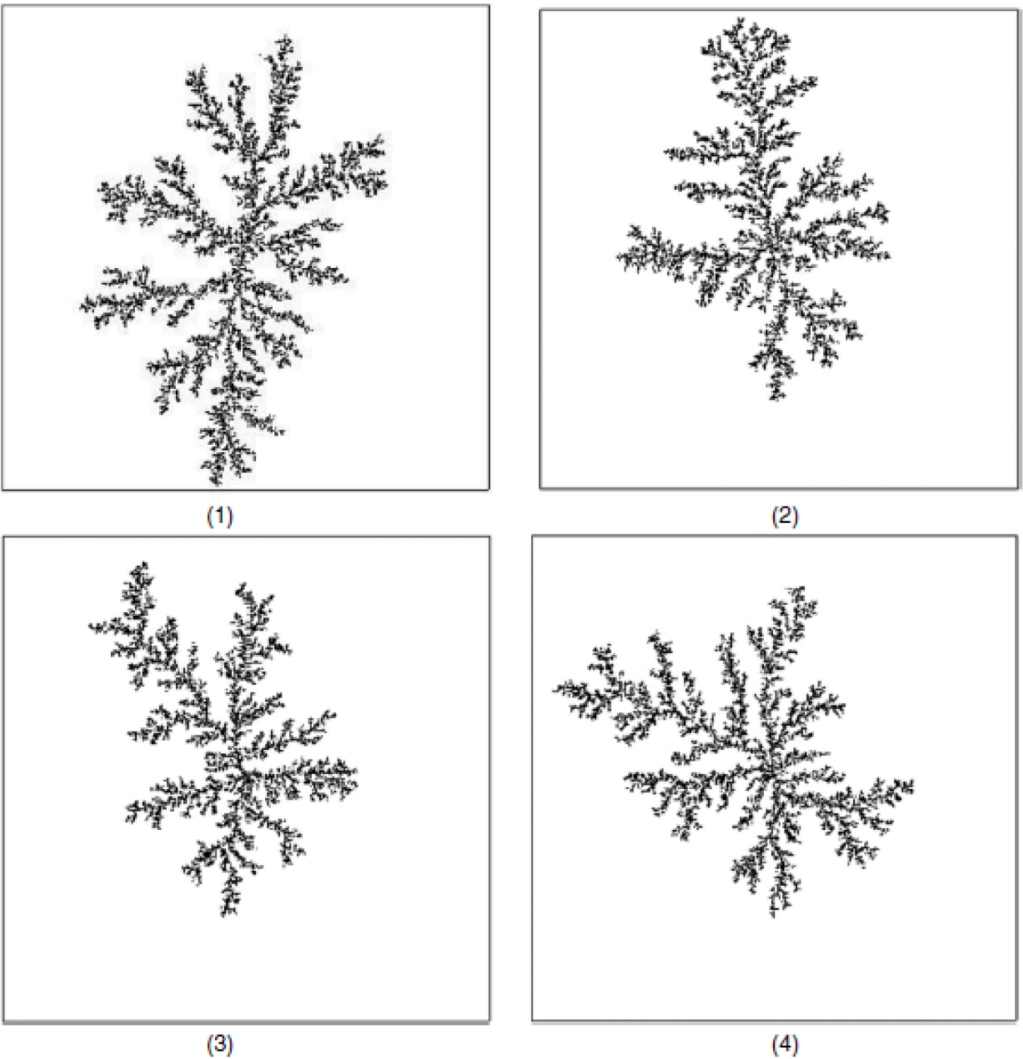


Fig. 10. Multiple fractal patterns generated by DLA model (Yu et al., 2020).

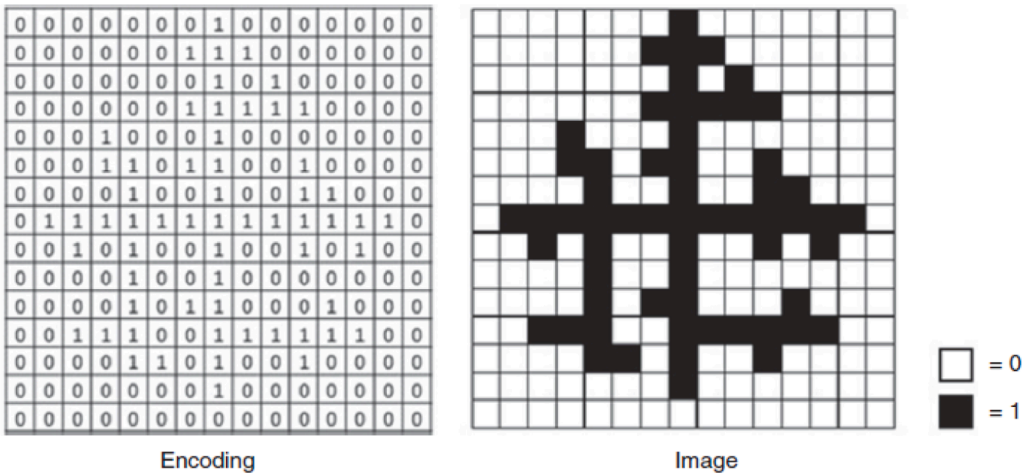


Fig. 11. Binary representation of a wormhole network (Yu et al., 2020).

wells. In practice, vertical CHOPS wells in suitable reservoirs can achieve 12–20% recovery of OOIP, while non-CHOPS typically yield only 8 to ten percent recovery, owing to the absence of channels and quick decline in production. Horizontal CHOPS wells may still offer

efficiency advantages because their larger drainage surface facilitates the development of multiple wormholes, resulting in greater overall heavy oil seepage, albeit at a slower rate per unit area compared with vertical wells. However, reservoir thickness places a constraint on their

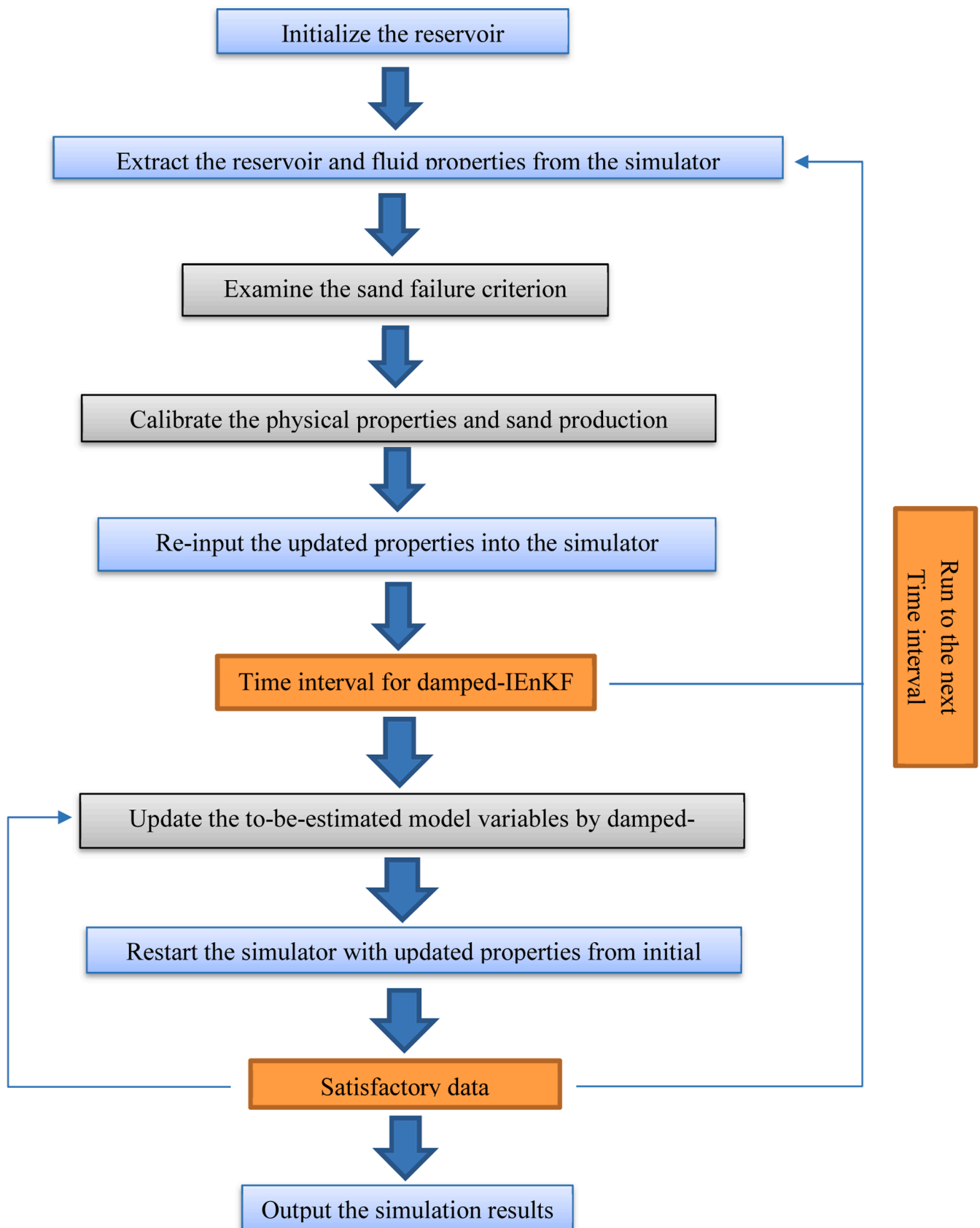


Fig. 12. Flowchart for an integrated CHOPS simulation (Shikai et al., 2023).

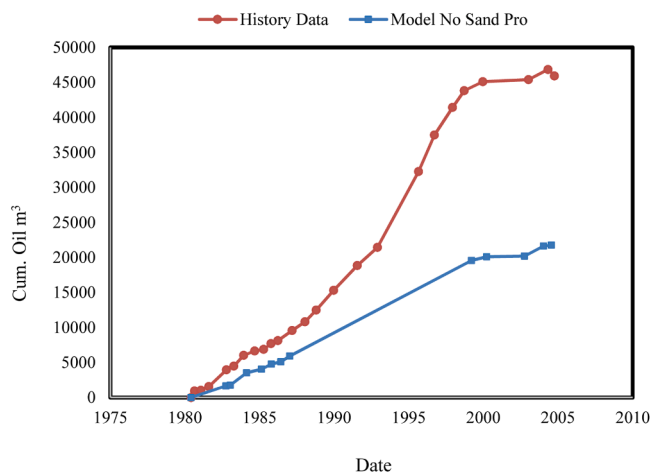


Fig. 13. History matching of cumulative oil production (Aghabarat et al., 2008).

performance, since wormhole penetration depth is restricted by the top and bottom boundaries of the reservoir. Consequently, the comparative advantages of sand influx seen in vertical wells are not expected to be fully reproduced in horizontal CHOPS wells. Liu et al., (2004) further contributed by developing an extensive semi-analytical model that coupled flow with wormhole dynamics to investigate their influence on CHOPS performance. The model employed the source and Green's functions technique, a technique commonly used for analysing unsteady flow in horizontal and multilateral wells. Within this framework, the influence of wormhole geometry, including shape, scale, diameter, branching, and associated pressure drop, on cold production was systematically investigated. The analysis focused on a CHOPS well situated within a box-shaped drainage system bounded by closed edges. Fluid behaviour was described as 3D flow of a fluid through a homogeneous, anisotropic porous medium, expressed using the diffusivity equation in combination with Darcy's law.⁸ The pressure drop at a given pressure node (i , j), produced by the inflow of a channel segment (i , j), which represents the j -th segment of the i -th wormhole series with segment length ΔL s and inflow rate q_i , was calculated by using the source and Green's functions method along with Laplace transformation of the time variable. The results demonstrated that wormhole geometry, particularly the extent, size, and branching, has a major impact on CHOPS performance. Though pressure drawdown along wormholes played a comparatively smaller role, neglecting this effect entirely could result in an overestimation of well productivity. This modelling approach underscores the need for accurately characterising wormhole geometry in predictive simulations to ensure reliable forecasting of CHOPS well behaviour.

Han et al., (2004) proposed a sanding model designed to predict the incremental oil recovery associated with a given quantity of sand. This model could be used to optimise CHOPS operations by balancing oil production. This helps limit sand flux and, in turn, lowers operating expenses, including costs related to sand disposal. With moderate recovery factors of about 15–20%, production rates ranging from 20 to 300 bbl/day, effective sand handling, and no requirement for thermal input, CHOPS has grown to contribute more than 20% of Canada's total oil production. In 2002, Canada produced approximately 2.9 million barrels of oil per day, of which over 0.6 million barrels of oil per day originated from CHOPS. Due to the distinctive characters of heavy oil fields, CHOPS wells may achieve productivities 10–20 times greater than those projected by Darcy's law calculations.⁹ In North Sea fields,

the implementation of this approach resulted in average rate increases of 30–40%, with some high-rate wells (1000–3000 m³/day) achieving gains exceeding 80%. In these cases, the dominant mechanism was the removal of mechanical skin near the wellbore. Gas bubble expansion as they migrate down the pressure gradient towards the well was identified as a key driver of heavy oil production, forming an essential component of the CHOPS process. Notably, laboratory experiments have demonstrated that the dispersed gas bubbles in the oil alone do not increase heavy oil mobility. Major flow enhancement due to bubble effects and foamy oil behaviour seems to need simultaneous sand flux. Canadian field experience has demonstrated that CHOPS can recover factors in excess of 20 % in recently recovered wells that have the right characteristics. A typical 40-month history of oil and sand production in a CHOPS well in the Edam area, east of the Lloydminster heavy-oil block, in Saskatchewan, Canada, is shown in Fig. 14. The sands of the reservoir in this area are at shallow depths of 400–500 m, low reservoir pressures of 3–4 Mpa, the porosity of 30–36 % and the permeability of 0.5–3 Darcies. The qualities of oil are identified by the 10–25 API gravities and viscosities ranging between 50 and 50 K mPa and s. In the absence of significant co-production of sand, vertically drilled wells normally give constant but low of 3–4 m³/day. In comparison, CHOPS operations provide production rates at least 10 times higher.

Preliminary calculations with this model highlight several important relationships:

- Enhancements in reservoir transport parameters, particularly permeability and porosity improvements due to sand removal, play a greater role in sustaining long-term production than changes in relative fluid velocity predicted by Darcy's law.
- Foamy oil behaviour, including bubble growth, increased compressibility, and reduced density, exerts a substantial influence on production flowrates. An improvement factor of three is observed when foamy behaviour is considered, compared with less than a doubling of oil rates when it is ignored. Additionally, foamy flow lowers pressures in the elastoplastic near the wellbore, creating greater overall pressure drawdown in the reservoir.

Liu et al. (2005) developed an extensive model to characterise the transient flow behaviour of mature CHOPS wells, providing a means to estimate potential wormhole configurations and assess pressure drops along wormholes. In such systems, channels that are created by high sand production serve as the principal conduits for fluid flow within the reservoir. The reservoir flow was first described using the Muskat and

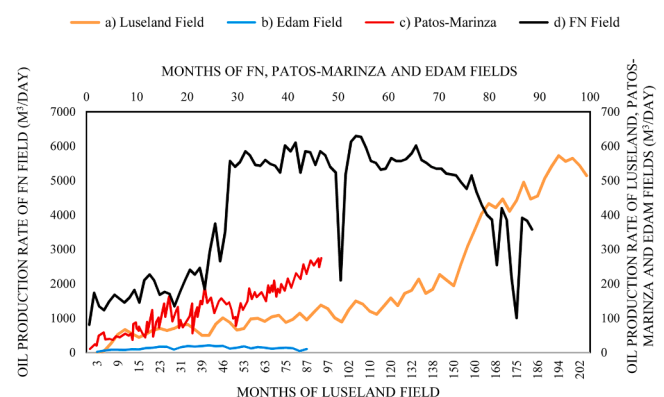


Fig. 14. Production performance curves of a) Luseland, b) Edam, c) Patos-Marinza and d) FN oil fields.

Meres multiphase equations, the dimensionless diffusivity equation, and the application of source and Green's functions with Laplace transformation for the time component. Wormhole flow was then represented using the Ergun equation to estimate pressure drops along higher

⁸ Appendix A (Section 8)

⁹ Appendix A (Section 9)

porosity, unconsolidated sand within wormhole segments. Reservoir and wormhole flows were coupled through a mass balance approach. The results indicated that higher cumulative sand production during the wormhole rapid-growth phase leads to an enhanced well productivity, particularly when wormholes propagate longitudinally. Pan et al. (2010) introduced and compared several numerical modelling approaches, including pseudo-bubble-point models, modified fractional-flow formulations, kinetic models for foamy oil flow,¹⁰ and related models for wormhole network growth. In a study by Sharifi et al. (2015), a fluidised sand algorithm was applied to simulate wormhole development in a Cold Lake formation, using current wellbore characters in a simulator. The algorithm expanded wormholes as the recovery process progressed. Results indicated that while different realisations of the geological model produced varying wormhole networks, production histories were consistent and heavy oil, associated water, and sand production could be matched to field data using a set of parameters across all realisations. These findings reveal that the well–wormhole model is capable of predicting process dynamics and identifying general growth directions of networks of wormhole in the reservoir. The principal mechanisms driving CHOPS are the flow of foamy oil, sand production, and sand failure. Foamy oil assists in mobilising sand and fluids, thereby enabling wormhole development. Since conventional PVT models cannot adequately represent foamy oil behaviour, a kinetic model was adopted, implemented through the reaction-kinetics functionality in CMG STARS. Sand mobilisation was represented by a sand failure criterion based on minimum fluidisation velocity. Individual wormholes were modelled in CMG STARS as extensions of existing wellbore features. Because STARS does not inherently support dynamic wellbore growth, a Dynamically Wellbore Module was introduced, which constantly restarted the simulator and applied wormhole growth criteria. Where criteria were met, wormholes were extended in the specified direction; otherwise, simulations were re-run until the criteria were satisfied (Istchenko et al., 2011). Complementary rock physics modelling was performed by Riazi et al. (2014) using well-log data in the region to evaluate how substitution of fluid affects elastic parameters such as density and P-wave and S-wave velocities. This was carried out using the Gassmann equation¹¹ in combination with the Batzle and Wang fluid relationships.¹² Subsequent 4D calibration was applied to time-lapse seismic data to minimise non-reservoir anomalies and isolate production-related changes. The calibrated seismic data were then subjected to model-based post-stack and pre-stack inversion in order to extract elastic properties at both horizontal and vertical scales across a CHOPS field located in Saskatchewan, Canada. Recent research on post-CHOPS recovery and reservoir characterisation has increasingly focused on three interrelated themes: understanding the dynamics of wormhole growth and foamy oil flow, optimising hybrid enhanced oil recovery processes, and coupling geomechanical behaviour with reservoir hydraulics. Together, these approaches aim to improve recovery efficiency, reduce uncertainty, and address the limitations inherent in conventional CHOPS operations.

• Sand–Wormhole Dynamics and Foamy Oil Behaviour

By combining rate transient analysis (RTA) with a pressure-gradient-based (PGB) sand-failure criterion, Jiang et al. (2024) examined the development and expansion of wormholes in CHOPS under conditions involving foamy oil behaviour. Their findings indicated that wormhole extent and productivity are strongly influenced by the degree of sand failure and by the properties of foamy oil. Sand output was governed by the breakdown pressure gradient as well as wormhole conductivity, whereas oil rates were primarily dictated by the overall coverage and intensity of wormholes. The

study also highlighted that the presence of foamy oil improved recovery efficiency and increased wormhole coverage relative to conventional oil systems. Taken together, this integration of RTA and PGB provides a structured diagnostic framework for assessing CHOPS performance under a variety of reservoir conditions.

• Hybrid Enhanced Oil Recovery Optimisation

Ma et al., (2018b) introduced a hybrid optimisation algorithm to improve the economic performance of post-CHOPS reservoirs. The approach considered combinations of CO₂-cyclic solvent injection (CO₂-CSI) with waterflooding (WF) or gas flooding (GF). Their study concluded that the CO₂-CSI + GF process provided the highest net present value (NPV). Across all cases, optimum NPV was obtained when producer bottom-hole pressures were kept at their lowest values.

• Coupled Mechanical–Hydraulic Modelling

Hou et al. (2024) developed an integrated optimisation technique for crossbreed injection of steam–solvent in depleted CHOPS fields, explicitly incorporating networks of wormholes and foamy oil flow. More broadly, recent literature emphasises that to fully evaluate the effects of sand production on reservoir performance, it is essential to consider not only flow-related factors such as porosity increases but also the coupling of geomechanical properties with hydraulic behaviour. This can be achieved through detailed modelling and simulation of the CHOPS process. Such approaches allow multiple realisations of fractal wormhole networks to be constrained against observed production data, thereby enabling sensitivity assessments of CHOPS performance under varying wormhole configurations. By further integrating CHOPS models with normalised data assimilation techniques, researchers have developed ensemble-based frameworks capable of quantitatively describing the dynamic evolution of wormhole propagation in CHOPS reservoirs. Inevitably, all models require calibration, with several reservoir parameters tuned to reproduce field observations of oil, water, and sand production. Among these, fluidisation velocity emerges as the critical history-matching parameter governing wormhole growth. By incorporating wormhole networks and foamy oil dynamics, and using net present value (NPV) as the optimisation criterion, modified algorithms can be applied to design and optimise production–injection strategies for CHOPS developments.

In summary, CHOPS represents a distinctive primary recovery technology for heavy oil, combining the interplay of wormhole development, foamy oil flow, and sand mobilisation. While the method has enabled significant production gains in unconsolidated reservoirs, recovery factors remain modest, and the challenges of sand handling, environmental impact, and reservoir instability persist. Advances in modelling and simulation, particularly those that integrate geomechanics, foamy oil behaviour, and ensemble-based data assimilation, have provided valuable insights into wormhole dynamics and production optimisation. Nonetheless, further refinement of these models, supported by high-quality field data, is essential to reduce uncertainty and to develop post-CHOPS recovery strategies that are both technically effective and economically viable.

In summary, studies on CHOPS modelling and simulation have mostly examined on developing integrated approaches to describe sand production, wormhole development, foamy oil behaviour, and reservoir performance. Various numerical models have been proposed, including elastoplastic damage models based on failure criteria, fractal-based wormhole growth models, coupled geomechanical–reservoir simulation frameworks, and ensemble-based data assimilation methods. These approaches have incorporated sand failure, fluidisation, porosity and permeability evolution, multiphase flow, and foamy oil dynamics using numerical tools such as CMG, MATLAB, and finite-element/finite-difference simulators. In addition, semi-analytical models, seismic-based reservoir characterization, and history-matched simulations have been applied to investigate wormhole geometry, pressure behaviour, production performance, and reservoir changes during CHOPS

¹⁰ Appendix A (Section 10)

¹¹ Appendix A (Section 11)

¹² Appendix A (Section 12)

operations. Recent studies have further integrated machine-assisted optimization, hybrid EOR modelling, and coupled mechanical–hydraulic simulations to evaluate post-CHOPS recovery strategies. Overall, these modelling efforts provide a comprehensive framework for understanding wormhole propagation, sand mobilization, foamy oil flow, and the optimization of CHOPS production and recovery processes.

Although significant progress has been achieved in modelling CHOPS behaviour, published studies have reported different levels of success due to differences in modelling assumptions, coupling strategies, and available validation data. Early models mainly focused on sand failure and wormhole development using geomechanical approaches, whereas later studies incorporated foamy oil behaviour, multiphase flow, and data assimilation techniques. However, there is still no universally accepted modelling framework capable of fully representing the complex interaction between sand production, wormhole propagation, stress redistribution, and foamy oil dynamics. Different modelling approaches have shown specific advantages and limitations. Fully coupled geomechanical–reservoir models provide a more realistic representation of sand failure and reservoir deformation, but they are often computationally expensive and require extensive calibration. In contrast, semi-analytical and simplified wormhole models offer improved computational efficiency and provide valuable insights into the influence of wormhole geometry and conductivity, but they generally rely on assumptions regarding wormhole structure and flow behaviour. Recent data-driven and ensemble-based approaches improve prediction capability by integrating production data; however, their performance remains dependent on the quality and quantity of available field observations. A major limitation of existing CHOPS simulation studies is the lack of comprehensive field-scale validation. Many models have been evaluated using laboratory experiments, synthetic cases, or limited production histories, while direct measurements of wormhole growth, sand production, and reservoir-scale changes remain scarce. Consequently, important parameters such as sand failure criteria, fluidization velocity, porosity–permeability relationships, and wormhole growth mechanisms often require empirical calibration. Furthermore, differences between commercial simulators and coupled research models, including variations in PVT descriptions, boundary conditions, and treatment of foamy oil behaviour, can lead to discrepancies in predicted production performance. Future modelling efforts should therefore focus on developing integrated and computationally efficient frameworks that combine geomechanics, multiphase flow, advanced data assimilation, and real-time field monitoring. Such approaches can reduce uncertainty in wormhole prediction, improve history matching, and provide more reliable tools for optimizing CHOPS and post-CHOPS recovery strategies.

9. CHOPS process, field case studies

Dusseault et al. (2002) reported on a CHOPS project undertaken in the Taobao oil field, Jilin Province, China. The reservoir consists of unconsolidated sands with high porosity of around 35% and permeability of approximately 5 Darcy, indicating favourable conditions for CHOPS application. Operations were initiated in about 22 wells. Reported sand cuts ranged widely from 0.1% to 10% by volume, a broader variation than typically observed in Canadian fields. Water cuts were modest, varying between 0% and 52%, with an average of 5–8%. The study reviewed both the geological framework and production history of the Taobao project. Petrophysical and reservoir characteristics are summarised in Table 7. Prior to CHOPS implementation on 1 March 2001, overall field production was low, at about 360 barrels per day across all wells. Following CHOPS, production rates varied considerably, between 6 and 70 barrels per day, with older wells tending to perform at the lower end of this range. The results suggest that the Taobao oil field shares many geological and production characteristics with heavy oil fields in Canada and Venezuela. Higher sand cuts were generally

associated with higher oil production, while the presence of active edge water had little detrimental effect on well performance. Overall, the CHOPS wells at Taobao demonstrated success in both technical and economic terms.

Weatherill et al. (2005) reported the deployment of CHOPS technology in the Patos-Marinza heavy-oil field, which is situated in southern Albania. Discovered in 1928, the field is among the largest onshore oil accumulations in Europe and has an estimated OOIP of more than 300 million m³. The field spans roughly 5 km by 14 km, with oil gravities ranging from 0.86 to 1.05 (3–33°API). By June 2004, more than 2400 wells had been drilled with an average spacing of roughly 3.6 ha, resulting in cumulative production of about 19 million m³. Despite this extensive development, primary recovery was forecast at only 6% of OOIP, with most wells achieving less than 10% recovery. Key reservoir properties are summarised in Table 8. In mid-2004, after a change in operatorship, an intensive programme of well interventions and CHOPS implementation was launched. A production plot covering the period 2002–2005, shown in Fig. 14(c), demonstrates the significant impact of this programme. Results showed that:

- Production increased steadily from the start of CHOPS operations in 2002, reaching about 275 m³/d by July 2005 as more wells were added.
- Additional production of nearly 240 cubic metres per day was achieved through the installation of new pumping systems, which enabled greater drawdown, facilitated sand co-production, and supported CHOPS development. This represented almost a tenfold rise in overall output.
- From the time when the development programme began in mid-2004, incremental production has remained stable at approximately 180 m³/d.

The experience at Patos-Marinza mirrors outcomes observed in other international CHOPS applications, such as the Taobao oil field in China and heavy oil fields in western Canada. In all cases, conventional primary recovery methods delivered low recovery factors, typically less than 10%, whereas CHOPS significantly enhanced production despite challenges related to sand management. These comparisons underline the wider applicability of CHOPS as a viable technology for unconsolidated heavy oil reservoirs beyond its original Canadian context, demonstrating both technical effectiveness and economic viability under diverse geological settings.

Wang et al. (2005) reported on the application of CHOPS in the Fula oil field, on the southern flank of the Muglad Basin in Sudan. The reservoir, comprising unconsolidated sandstones at a depth of around 3500 ft, was developed through initial field trials in which 20 heavy oil wells were equipped with progressing cavity pumps (PCPs) to manage sand production effectively. Key reservoir properties are summarised in Table 9. Integrated completion strategies were adopted to enhance heavy oil recovery, emphasising the need to mitigate the limitations of conventional sand-control methods while harnessing the benefits of controlled sand production.

Table 7
Reservoir rock and fluid Properties of Taobao Oil field.

Properties	Values
Depth (m)	150–200
Porosity (%)	33–39
Permeability (D)	5.1
BHSP (MPa)	3.2
BHST (°C)	18
S _w (%)	5
S _g (%)	0
Viscosity (cP)	1851
Thickness of pay zones (m)	3–11
Lithology	Unconsolidated Fine Sands

Table 8

The Patos-Marinza heavy oil field properties.

Properties	Values
Depth (m)	60–1800
Porosity (%)	15–40
Permeability (mD)	1–2000
Oil Gravity (Kg/m ³)	993
Oil Density (tonnes/m ³)	0.86–1.05
Effective Permeability (mD)	320
Dead Oil Viscosity (mPa.s)	10000
Live Oil Viscosity (mPa.s)	494
Marinza:	691
Patos:	
Solution Gas-Oil Ratio (SGOR) (m ³ /m ³)	26
Oil Formation Volume Factor (m ³ /m ³)	1.05
Rock Compressibility (10 ⁻⁶ kPa ⁻¹)	3.0
1990s Mean Reservoir Pressure (kPa)	9230
Corresponding Depth (m)	1480
Initial Reservoir Pressure Gradient (kPa/m)	10.84
Ground Temperature at 50 m (C)	18
Geothermal Gradient (C/100 m)	1.65

Following drilling, PCPs were employed to deliberately initiate sand influx, while screen liners were installed to restrict the entry of particles larger than 0.5 mm into the wellbore, allowing finer sands to be co-produced with the oil. Under conventional recovery techniques, single-well productivity was typically in the range of 140–210 BOPD. During the early stages of field development, sand control using screen liners combined with rod pumps achieved daily production of approximately 220 BOPD. However, once the screen liners were removed and PCPs were deployed to implement CHOPS, oil production rose to 436 BOPD with a sand cut of around 6% at the wellhead. The productivity index of CHOPS was about ten times greater than that achieved under sand-control operations with screen liners.

Young et al. (2010) investigated the feasibility of CHOPS in Alaska's North Slope, a major petroleum basin that includes two of North America's largest producing fields, Prudhoe Bay and Kuparuk River. Despite its vast resource potential, development has been constrained by the difficulties associated with heavy oil recovery in Arctic environments. Estimates place the oil in place between 18 and 27 Bbbl, with gravities of 11–12°API, distributed across several reservoir intervals. This interval comprises clean, unconsolidated sands interbedded with silty mudstone layers that lack reservoir quality. Oil properties improve eastward with depth of burial, yielding less viscous crude that may be amenable to cold production supported by solution-gas drive. In contrast, the shallower, more viscous oils to the west are considered more suitable for thermally assisted recovery. Surface-driven progressing cavity pump (PCP) systems, although widely applied in CHOPS vertical wells in Canada and horizontal wells with sand segregation in Venezuela, encounter restrictions when applied to deviated wells with high sand influx. To assess CHOPS potential under such conditions, a flow-back assessment was performed on a well. Downhole gauges were installed, and the well was open to production with a surface-driven PCP pump (Fig. 15). The trial demonstrated that lift performance was constrained by torque, resulting from drag forces between the drive rods and the oil. A subsequent appraisal well, MPS-41, was drilled with the objective of collecting high-quality PVT samples using an open-hole modular dynamic tester (MDT), followed by a cased-hole drill-stem test (DST) (Fig. 16). The results revealed unexpectedly high

permeability and a substantial amount of dissolved gas in the upper interval, indicating that extensive sand production may not be necessary for effective primary recovery. This led to the conclusion that horizontal well development could represent a viable alternative to conventional CHOPS deployment in this setting. In contrast with experiences in regions such as China, Sudan, and Albania, where substantial sand influx has been closely tied to productivity gains, the Alaska case indicates that favourable reservoir quality and dissolved gas drive may reduce reliance on aggressive sand production, highlighting the importance of tailoring CHOPS strategies to local geological conditions. Wang et al., (2011) reported the successful application of CHOPS in the B heavy oil reservoir of the FN field in Sudan. oil, with an API of 18° and viscosity between 6000 and 10,000 mPa.s at 29 °C, was characterised by low gas-oil ratios of 7–30 scf/bbl (Table 10). Between 2004 and 2006, seventy producing wells were commissioned with an optimised perforation ratio of 30% of total net pay. Water cuts were maintained below 10% with an annual offtake rate of 2%. From 2007 onwards, forty infill wells, including horizontal completions, were drilled to mitigate water coning. By 2010, the recovery factor had reached 13% with a water cut of 46%, outperforming many comparable heavy oil reservoirs. Average producer uptime exceeded 85%. During appraisal, four wells were drilled to delineate reservoir boundaries and tested under CHOPS conditions with PCP lift. One appraisal well directly compared productivity with and without sand control, demonstrating that CHOPS achieved outputs of up to 500 BOPD, two to three times greater than sand-controlled production. PCP types available on the market were carefully screened to meet lifting demands at depths below 1000 m in the presence of sand. PCPs were generally installed 100 m above the top perforation (Fig. 17). Produced sand and oil flowed into a sand trap, where sand was separated by gravity and deposited at the base through a slotted pipe (Fig. 18). Fig. 14(d) illustrates the production performance of the FN field between 2004 and 2011.

Sanyal et al. (2011) presented valuable field data and performance analysis from a CHOPS pilot project in Kuwait. The reservoir comprises four oil-bearing sand layers separated by shale breaks, each zone ranging from approximately 10–30 ft in thickness. Their evaluation focused on three pilot wells, all of which exhibited negative skin values consistent with typical CHOPS performance. Special core analysis from one of the wells revealed oil-phase permeabilities between 16% and 87% of the corresponding air permeability. Andarcia et al., (2014) also gave further evidence of a wormhole formation during CHOPS by carrying out cold production tests in a thin heavy-oil-bearing sand in the Llanos Basin, Colombia. In the tests, hydraulic communication was recorded with a neighboring well 25 m away the test well. Interestingly, lightweight ceramic proppant, which was initially meant to be used in gravel packing of the adjacent well, would enter the producing well as soon as the influx of sand started. The passage of synthetic ceramic particles of a diameter greater than 1000 microns through the porous medium was a confirmation of the formation of high-conductivity channels, or wormholes. Table 11 summarises the reservoir properties to be used in these studies. Combined with some field work in Canada, China, Sudan, Albania and Alaska, the Kuwait and Colombia pilots also indicate that CHOPS can be used in very diverse geological and operational environments further justifying its universal applicability as a key heavy oil recovery method.

Sharifi et al. (2017) created a model that matched history to examine a petroleum reservoir in Cold Lake region of Alberta, Canada. Table 12 summarises the main reservoir characteristics that will be utilised in the simulation. In their analysis, they give us a succinct analysis of the results that were achieved after the fourth year of operation which are presented in Table 13. The paper emphasizes the ability of calibrated reservoir models to simulate the production history as well as the dynamic effects of wormhole development, foamy oil flow, and sand production on the long-term performance. As the modelling work is presented in relation to the diverse field case studies as described previously in Canada, China, Sudan, Albania, Kuwait, Colombia, and

Table 9

The Fula oil field Properties.

Properties	Values
Depth (m)	1200–1300
Porosity (%)	31
Permeability (D)	2
API Gravity (°)	19–21

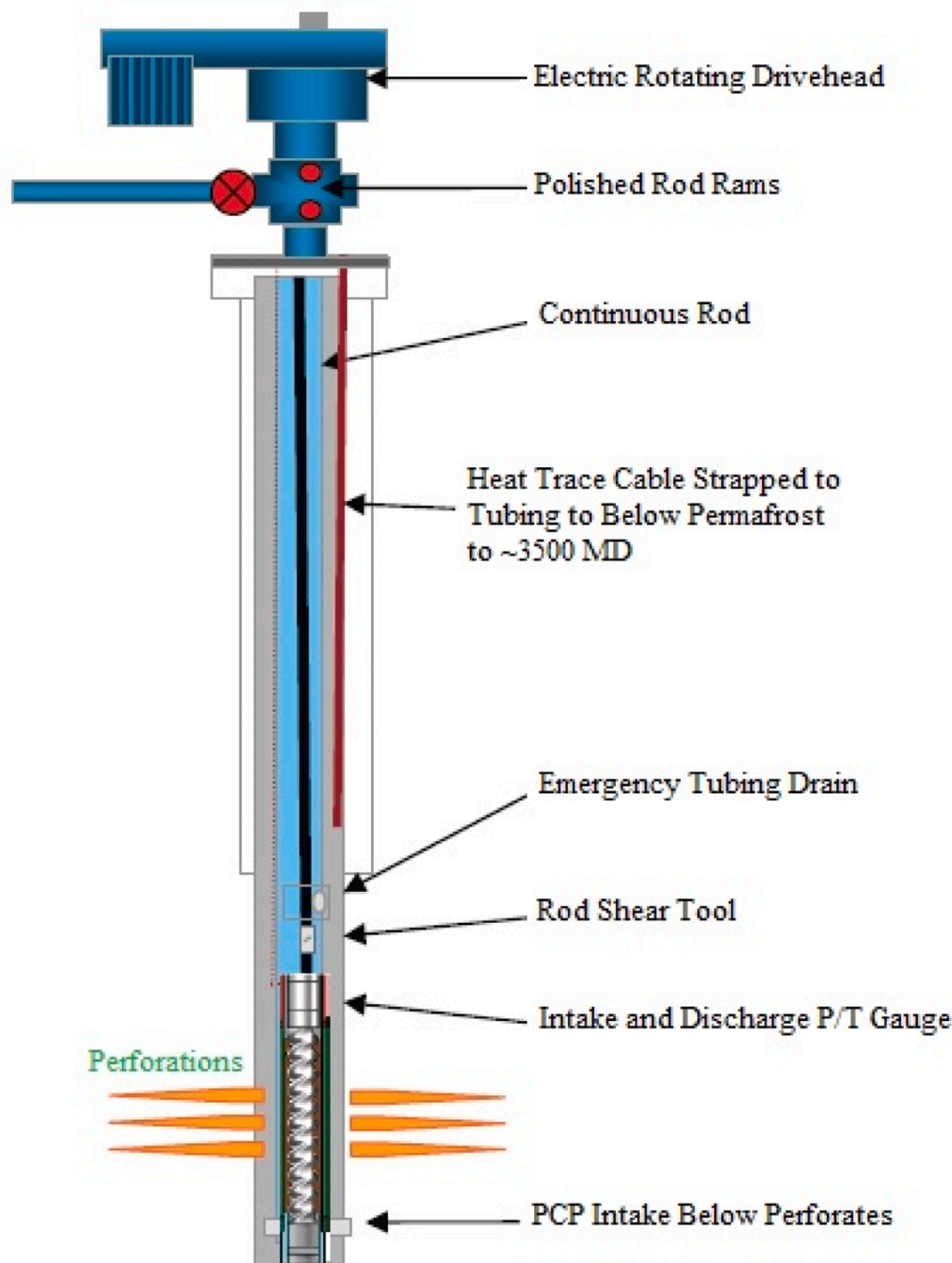


Fig. 15. Wellbore sketch with PCPs (Young et al., 2010).

Alaska, this modelling work explains the complementary nature of simulation in the validation of CHOPS behaviour. The process is proven to be practically viable in a wide variety of geological settings by field observations, and history-matched models, like this one, present a quantitative framework with which recovery efficiency can be predicted and post-CHOPS optimisation strategies guided.

The successful application of CHOPS in several Canadian reservoirs was investigated by Dusseault et al., (2000b). In Luseland field, old vertically completed wells were changed to CHOPS in 1994–1996. Some of its properties and results are listed in Table 14 and Table 15, respectively. Fig. 14(a) is a plot of the oil production rates of the Luseland field from its inception (1982) to 1998.

Fig. 14(b) presents a representative 36-month oil production history

for a CHOPS well in the Edam area, located east of the Lloydminster heavy-oil zone in Saskatchewan, Canada.

Reservoir characteristics for this case are summarised in Table 16. In the absence of substantial sand co-production, vertical wells in this area typically produced at steady but modest rates of 3–4 m³/d. By contrast, once CHOPS was applied, production rates increased by at least an order of magnitude (Han et al., 2004). The Edam case reinforces the strong relationship between sand influx and enhanced productivity, demonstrating how wormhole development and foamy oil flow can sustain markedly higher oil rates compared with conventional cold production. It also exemplifies the broader trend observed across Canadian heavy oil fields, where CHOPS has consistently converted reservoirs of otherwise marginal economics into commercially viable projects.

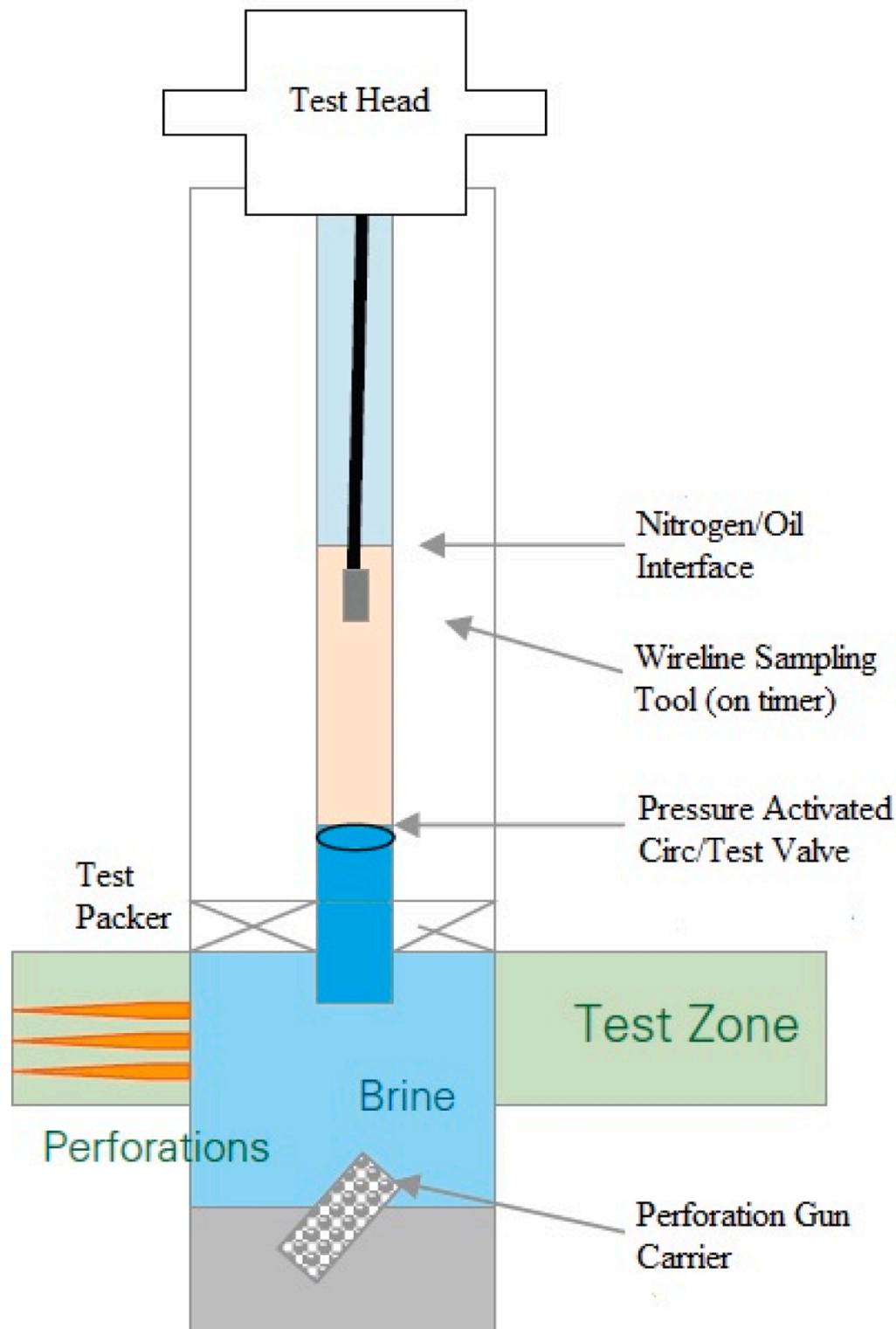


Fig. 16. Drill stem test sketch (Young et al., 2010).

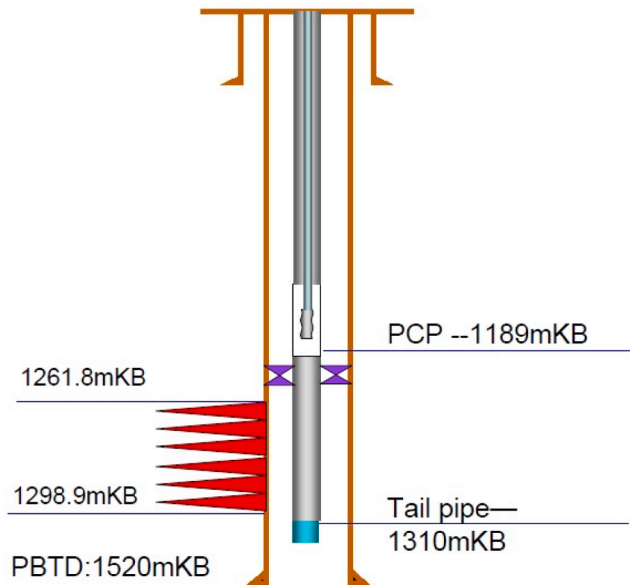
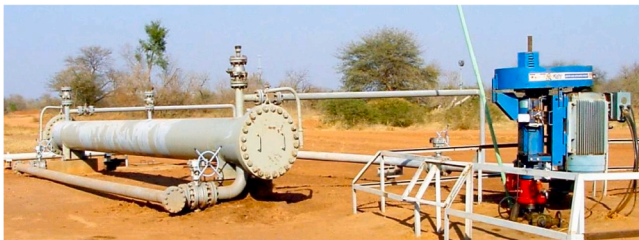
Riazi et al., (2014) investigated the Dee Valley heavy oil field, situated east of Lloydminster near the Alberta–Saskatchewan border and operated by Husky Energy Ltd. Production from the field began in the 1970s and continues today, targeting nonconsolidated Sparky sandstone at a depth of approximately 464 m. The reservoir, classified as a thin heavy oil system, has been developed using CHOPS as the primary recovery method. Key reservoir parameters are presented in Table 17. To

track reservoir behaviour, model-based post-stack and pre-stack seismic inversion were applied to time-lapse seismic data, allowing elastic properties to be extracted at both horizontal and vertical scales. The seismic inversion results showed strong correlation with production changes observed in the field, demonstrating the value of seismic methods for characterising CHOPS performance. Compared with modelling-focused studies in Cold Lake (Sharifi et al., 2017) and Taobao

Table 10

The characteristics of FN oil field of Sudan.

Properties	Values
Depth (m)	1250
Average Net Pay Thickness (m)	35
In-situ Viscosity (mPa.s)	300
Surface Viscosity (mPa.s)	6000–10000
Porosity (%)	26–34
Oil Saturation (%)	61–86
Permeability (mD)	3000
Field Average Surface Temperature (°C)	29
API Gravity (°)	18
GOR (SCF/BBL)	7–30

**Fig. 17.** Typical borehole lifting structure with PCPs (Wang et al., 2011).**Fig. 18.** Surface sand trap (Wang et al., 2011).**Table 11**

The Llanos Basin field properties.

Properties	Values
Depth (ft)	2660
Initial Reservoir Pressure (psi)	1150
Reservoir Temperature (° F)	155
Viscosity (cP)	2500
Solution Gas (SCF/STB)	1–3
Porosity (%)	28–30
Net Pay Thickness (ft)	5–10
Water Saturation (%)	10–25
API Gravity (°)	8.5

Table 12

Properties of Cold-Lake CHOPS reservoir.

Properties	Values
Depth to reservoir top (m)	291
Net pay (m)	~6
Porosity (%)	6 – 40
Oil saturation (%)	4 – 80
Solution gas-to-oil ratio (m ³ /m ³)	10
Horizontal rock permeability k _h (mD)	30–8500
k _v /k _h	0.8
Effective rock compressibility (1/kPa)	5 × 10 ⁻⁶
Rock heat capacity (kJ/m ³ °C)	2600
Rock thermal conductivity (kJ/m day °C)	660
Reference pressure (kPa)	2500
Reference depth (m)	291
Initial reservoir temperature, °C	20
Gas phase viscosity (cP)	0.00864 (1.574 + 0.0044 · T(°C))

Table 13

CHOPS process results after four years in the Cold-Lake field.

Process	Cum. oil prod. (m ³)	RF%
Cold Production	158614	10.3
Water flooding	32167	2.1
Cyclic CO ₂ injection (CCI)	38837	2.4
Hot water flooding	31004	2.0
Hot WAG, ratio = 1	29100	1.9
CO ₂ -hot water, ratio 25:75	102146	6.6
CO ₂ - hot water, ratio 50:50	88943	5.6
CO ₂ -hot water, ratio 75:25	64543	4.0
CO ₂ -hot water, ratio 99:1	56476	3.6
CO ₂ -hot water, ratio 99.5:0.5	48343	3.0

Table 14

Luseland field properties.

Properties	Values
Depth (m)	730
BHSP (MPa)	6.3
Bubble point (MPa)	< 6
BHST (°C)	30
Porosity (%)	~30
Permeability (D)	2–4
S _w (%)	28
Thickness (m)	5–15
Viscosity in situ (cP)	1400
Dead oil viscosity (cP)	12000–30000
API gravity (°)	11–13.4
Solution gas type	> 90% CH ₄
Gas solution const.	0.20 bar ⁻¹
	~50 scf/B · 500 m

Table 15

Luseland field history.

Well No	Cumulative produced oil m ³	Well life (month)	Average oil production (m ³ / month)
a	40	8	5
b	705	6	118
c	4870	59	82
d	6850	30	228
e	10940	48	227

production-driven reservoir changes, offering a complementary perspective on CHOPS behaviour.

CHOPs in the Lloydminster reservoirs typically recovers only 5–10 % of the OIIP. Among the post-CHOPS strategies evaluated, cyclic solvent injection has emerged as the most promising follow-up method. For the Effective Permeability model, 2-D radial primary production simulations were first performed for an actual Lloydminster well using AITF's

(Dusseault et al., 2002), the Dee Valley case highlights how seismic monitoring provides an independent means of validating

Table 16
The Edam oil field properties.

Properties	Values
Depth (m)	400–500
Formation Pressure (MPa)	3–4
Porosity (%)	30–36
Permeability (D)	0.5–3
API Gravity (°)	10–25
Viscosity (mPa.s)	50–50000

Table 17
The Dee Valley oil field properties.

Properties	Values
Depth (m)	464
Initial Pressure (kPa)	3900
Porosity (%)	18–38
Horizontal Permeability (mD)	32–18033
API Gravity (°)	11.5

sand transport and foamy oil models and the post-CHOPS reservoir results were then converted to a Cartesian grid for the CSI simulations. Some initial Pre-CHOPS reservoir conditions are listed in Table 18. Increasing gas exsolution rates and performing non-isothermal simulations resulted in increased oil production by 9% and 11%, respectively (Chang et al., 2012).

In order to have a brief comparison between oil production rates of fields of Patos-Marinza, FN, Luseland and Edam, we have tried to plot them together in Fig. 14; however, the time data and scale of fields are not the same. However, based on the Fig. 19, the distribution of CHOPS process in the field scale around the world has been illustrated as follows: Canada 42%, Sudan 17%, China 9%, USA 8%, Kuwait 8%, Albania 8%, and Colombia 8%. In addition, Fig. 20 shows the distribution of all publications which have been used during our current study. Based on the Fig. 20, Canada and the USA have the most work in the heavy oil reservoirs, especially on the CHOPS process by 76 and 9% respectively around the world.

In summary, field studies have demonstrated the successful implementation of CHOPS in a wide range of unconsolidated heavy oil reservoirs worldwide. Several field applications, including Taobao in China, Patos-Marinza in Albania, Fula and FN in Sudan, North Slope in Alaska, and reservoirs in Canada, Kuwait, and Colombia, have evaluated CHOPS performance through production monitoring, well testing, and reservoir characterisation. These studies mainly focused on the use of progressing cavity pumps (PCPs), controlled sand production, and reservoir management strategies to enhance oil recovery. The results showed that CHOPS application generally increased production by promoting sand influx, wormhole development, and improved reservoir connectivity, with higher productivity often associated with greater sand production. Different field investigations also applied complementary techniques, such as seismic monitoring, history-matched reservoir simulation, and post-CHOPS recovery modelling, to evaluate reservoir behaviour and optimise future recovery strategies. Overall, the

Table 18
Initial pre-CHOPS conditions of Lloydminster reservoir.

Properties	Values
Pressure (kPa)	3300
Temperature (°C)	23.4
Dead oil viscosity (mPa.s)	18775
GOR (Std m ³ /m ³)	7
Thickness (m)	3.57
Porosity (%)	18.14
Permeability (mD)	311.82
S _o (%)	46
S _w (%)	54

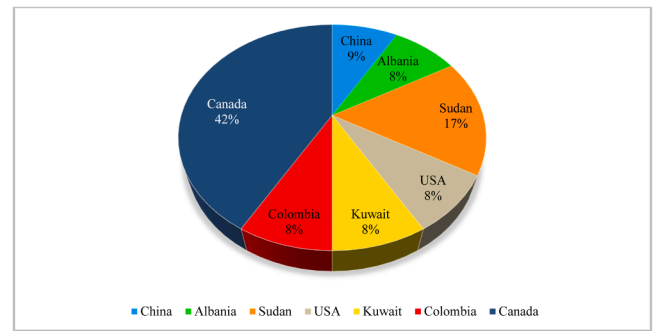


Fig. 19. Distribution of CHOPS process in the field scale around the world.

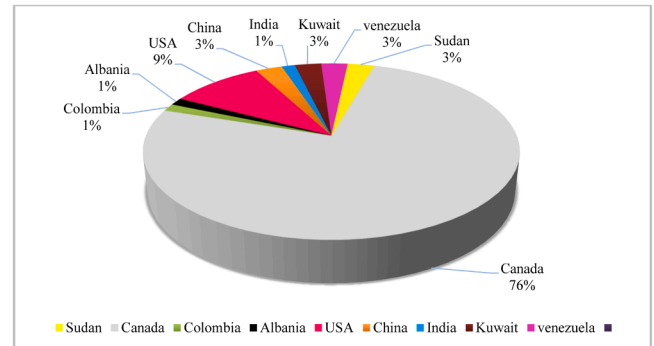


Fig. 20. Distribution of all publications which has been used in the current study.

reported field experiences confirmed the applicability of CHOPS in diverse geological settings and highlighted its effectiveness as a primary recovery method for unconsolidated heavy oil reservoirs.

Field-scale applications have demonstrated the technical and economic feasibility of CHOPS across diverse geological settings, including Canada, China, Sudan, Albania, Kuwait, Colombia, and Alaska. However, field experiences also indicate that CHOPS performance is highly dependent on reservoir-specific conditions. In several cases, such as Taobao, Patos-Marinza, FN, and Canadian heavy oil fields, increased sand production was directly associated with higher oil productivity, confirming the importance of wormhole development and sand mobilization. In contrast, the Alaska case demonstrated that favourable reservoir quality, high permeability, and sufficient dissolved gas content may reduce the necessity for aggressive sand production. These differences highlight that sand production should not be considered the only controlling factor, and CHOPS performance results from the combined effects of reservoir properties, foamy oil behaviour, geomechanical conditions, and operational strategy. Comparison among different field applications also reveals significant variations in recovery performance. While CHOPS has improved production rates by several folds compared with conventional cold production, recovery factors remain generally limited, commonly below 20% of OOIP. The differences observed between fields are related to variations in oil viscosity, reservoir thickness, permeability, gas content, water behaviour, and well completion practices. For example, successful applications in Canada and Sudan benefited from effective PCP implementation and sand management strategies, whereas challenges related to artificial lift performance and sand control can limit applicability in other environments. Despite the successful field demonstrations, several limitations remain in the transferability of CHOPS technology. Many reported field cases lack detailed information regarding long-term wormhole evolution, sand production history, pressure behaviour, and reservoir-scale changes, which restricts the ability to develop predictive models applicable to different reservoirs. Furthermore, most successful applications have

been conducted in unconsolidated heavy oil reservoirs with favourable permeability and porosity, while the performance of CHOPS in more complex reservoirs remains uncertain. Overall, field studies confirm that CHOPS is a flexible technology with broad applicability; however, its success cannot be guaranteed by reservoir properties alone. Future developments should focus on improved reservoir screening criteria, integration of field monitoring technologies, and coupling of field observations with advanced simulation models to optimize CHOPS implementation and identify suitable post-CHOPS recovery strategies.

10. Future Research Directions for Improving CHOPS Performance

Although Cold Heavy Oil Production with Sand (CHOPS) has proven to be an effective and economically attractive method for producing heavy oil from unconsolidated reservoirs, several technical limitations still restrict its recovery potential. Future research should therefore focus on developing innovative approaches to improve production efficiency, increase ultimate recovery, reduce operational uncertainties, and enhance the environmental sustainability of the process. One of the most important future research areas is the optimization of sand production and wormhole development. Although sand influx is considered a key mechanism responsible for improving oil mobility and creating high-conductivity flow channels, uncontrolled sand production can lead to wellbore instability, excessive surface handling requirements, and operational problems. Future studies should investigate the optimum balance between sand production and reservoir stability through advanced geomechanical models, laboratory experiments, and real-time field monitoring. Improved prediction of wormhole initiation, growth, and connectivity could enable operators to control sand production more effectively and maximize reservoir drainage. Further improvements in CHOPS performance require a deeper understanding of foamy oil mechanisms. Gas bubble nucleation, expansion, and transport play a significant role in maintaining reservoir pressure and enhancing oil mobility; however, these processes remain difficult to quantify at field scale. Future research should combine pore-scale visualization techniques, micro-CT imaging, digital rock physics, and advanced multiphase flow simulation to develop more accurate models of foamy oil behaviour. These developments could improve production forecasting and provide better guidelines for operating pressure management. The application of advanced reservoir monitoring technologies represents another promising direction for improving CHOPS. The integration of real-time data acquisition systems, including distributed temperature sensing (DTS), distributed acoustic sensing (DAS), pressure monitoring, and production surveillance, could provide valuable information about reservoir changes during operation. Such technologies may allow early identification of wormhole development, flow channel evolution, and production problems, leading to more efficient reservoir management strategies. Future improvements can also be achieved through the development of advanced numerical simulation approaches. Conventional reservoir models often simplify the complex interaction between geomechanics, sand failure, multiphase flow, and foamy oil behaviour. Therefore, coupled geomechanical-reservoir simulation frameworks should be further developed to better represent CHOPS mechanisms. In addition, artificial intelligence (AI), machine learning (ML), and physics-informed neural networks (PINNs) could be applied to improve history matching, predict production performance, and optimize operational parameters using large field datasets. Another important research direction is improving post-CHOPS recovery strategies. Since primary CHOPS recovery typically remains limited, future studies should investigate more efficient combinations of CHOPS with enhanced oil recovery (EOR) technologies. Hybrid methods involving solvent injection, cyclic steam stimulation, CO₂ injection, and other low-carbon recovery processes should be optimized according to reservoir conditions and wormhole characteristics. A better understanding of residual oil distribution after CHOPS will be essential for designing effective

recovery strategies. Operational improvements should also focus on reducing equipment limitations and production losses. Development of more durable artificial lift systems, improved progressive cavity pump (PCP) designs, and optimized sand separation and handling facilities could increase well reliability and reduce maintenance requirements. In addition, improved well completion designs may help control excessive sand production while maintaining sufficient reservoir connectivity. From an environmental perspective, future CHOPS development should emphasize reducing greenhouse gas emissions and improving overall sustainability. More accurate measurement and mitigation of methane emissions, improved produced-water management, and integration with carbon capture, utilization, and storage (CCUS) technologies could reduce the environmental footprint of heavy oil production. Life-cycle assessment (LCA) approaches should also be incorporated into future studies to evaluate the long-term environmental performance of CHOPS compared with other heavy oil recovery methods. Finally, future field development should prioritize systematic data collection and collaboration between industry and research institutions. The limited availability of high-quality field data remains one of the major challenges in improving CHOPS models and forecasting methods. Continuous recording of sand production, gas production, pressure changes, and production behaviour would significantly improve reservoir characterization and enable more reliable optimization of future CHOPS operations. Overall, future advancements in CHOPS will depend on the integration of reservoir engineering, geomechanics, multiphase flow modelling, digital technologies, and sustainable production practices. These developments could significantly enhance recovery efficiency, reduce operational risks, and extend the application of CHOPS as a competitive and environmentally responsible technology for heavy oil production.

11. Conclusion and future outlook

In unconsolidated sand reservoirs characterised by high porosity (>25%), high permeability (>1 Darcy), low oil gravity (<20°API), and depths ranging from 60 to 1800 m, with in situ oil viscosities of 200–3000 cP, economic recovery can be achieved through the non-thermal method known as cold heavy oil production with sand (CHOPS). A notable advantage of CHOPS is its applicability to relatively thin reservoirs, typically 3–10 m thick, where thermal methods are uneconomic. In such reservoirs, grain sizes generally range from 80 to 150 µm, initial water saturations are low, and initial pressures typically fall between 3 and 10 MPa. Even though sand production encourages more oil production altogether, typical CHOPS recovery factors are still very low, around 5–15%. Also, it can be increased during the Post-CHOPS processes only 2–8% using cyclic steam stimulation, steam-assisted gravity drainage, cyclic solvent injection, VAPEX, and CO₂-based enhanced oil recovery. Future developments should therefore focus on maximizing ultimate recovery while preserving the economic advantages of non-thermal production. Sand production in CHOPS leads to the formation of wormholes within the reservoir, creating significant pressure gradients along their length. Together with foamy oil flow, wormhole development represents one of the two principal mechanisms underpinning the effectiveness of the CHOPS process. Future studies should integrate advanced laboratory visualization techniques, high-resolution imaging, geomechanical modelling, and field-scale numerical simulations to establish more reliable predictive models for wormhole development and reservoir performance.

However, CHOPS production faces several technical challenges, primarily related to sand management, foamy oil behavior, and methane emissions. The process of sand influx to enhance oil production also introduces challenges in maintaining wellbore stability and managing the sand at the surface. Additionally, the foamy oil phenomenon, where gas bubbles remain dispersed within the oil, creates complex multiphase flow and requires specialized modeling and simulation techniques. The complex behaviour of foamy oil remains insufficiently

understood. Bubble nucleation, growth, coalescence, and transport directly affect pressure depletion, mobility, and production rates, yet current multiphase flow models often fail to fully capture these processes. Future research should combine pore-scale experiments, micro-fluidic visualization, digital rock analysis, and multiphase flow simulations to improve the physical description of foamy oil and enhance production forecasting under varying reservoir conditions.

Furthermore, CHOPS wells often experience higher methane emissions than conventional oil production, necessitating improved measurement and mitigation strategies. Furthermore, performing the experimental works, modeling, and simulation study can provide better vision to make a decision during the field case studies. For economic reasons, CHOPS wells are seldom cored, and records of sand and gas production are often not maintained, which complicates the process of history matching. Systematic measurement of such data would provide significant value in forecasting and optimising post-CHOPS recovery strategies. Future field developments should emphasize systematic collection of production data, continuous reservoir surveillance, and comprehensive monitoring programs. Such datasets would substantially improve model calibration, uncertainty quantification, and the optimization of post-CHOPS recovery strategies. Overall, the future advancement of CHOPS will depend on interdisciplinary collaboration among reservoir engineering, geomechanics, multiphase flow physics, data science, and environmental engineering. Continued progress in these areas has the potential to significantly improve recovery efficiency, reduce operational risks, minimize environmental impacts, and

reinforce CHOPS as one of the most cost-effective and sustainable technologies for the development of unconsolidated heavy oil reservoirs.

CRediT authorship contribution statement

Dhifaf Sadeq: Writing – review & editing, Writing – original draft, Supervision, Methodology, Investigation, Data curation, Conceptualization. **Hamid Reza Nasriani:** Writing – review & editing, Writing – original draft, Visualization, Validation, Project administration, Methodology, Investigation, Data curation, Conceptualization. **Asghar Gandomkar:** Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Farshid Torabi:** Writing – review & editing, Writing – original draft, Validation, Supervision, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Aidina Khajeali:** Writing – review & editing, Writing – original draft, Validation, Software, Methodology, Investigation, Data curation. **Omar Al-Fatlawi:** Writing – review & editing, Writing – original draft, Methodology, Investigation, Conceptualization.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

The following formulas are related to the CHOPS process, modeling, simulation, and optimization works section.

Section 1 . The Drucker- Prager criterion failure surface which used by [Shao et al., \(2002\)](#) in their proposed elastoplastic damage model:

$$f(\hat{\sigma}^{eff}) = \hat{q}^{eff} - A\hat{p}^{eff} = 0 \quad (1)$$

$$\text{with } \hat{p}^{eff} = \hat{\sigma}_{kk}^{eff} / 3 \quad (2)$$

$$\text{and } \hat{s}_{ij} = \hat{\sigma}_{ij}^{eff} - \hat{p}^{eff} \delta_{ij} \quad (3)$$

$$A = A_0 (1 - d) \quad (4)$$

$$f(\hat{\sigma}^{eff}, \eta) = \hat{q}^{eff} - \eta A \hat{p}^{eff} = 0 \quad , \quad 0 \leq \eta \leq 1 \quad (5)$$

Section 2 . The sand-arch stability criterion which used by [Yu et al., \(2020\)](#) to couple the compositional flow simulation with sand fluidization and production:

$$Pcr = \left(\frac{dp}{dr} \right)_{critical} = \frac{2fC_u}{R_c} \quad (6)$$

$$R_c = x_{max}^2 / z_{max} \quad (7)$$

$$C_u = \frac{a + b}{(\phi - c)} \quad (8)$$

$$C_u (kPa) = \frac{12.78 + 1.01}{(\phi - 0.291)} \quad (9)$$

Section 3 . The modified PGB sand failure criterion which [Shikai et al., \(2023\)](#) coupled with some other models together to characterize the wormhole growth:

$$\Delta p_m \vec{S}_m - (\vec{a} + \lambda \eta \rho \vec{g}) V_m = 0 \quad \text{if} \quad \Delta P_m > P_{bd} \text{ and } PV_d > PV_u \quad (10)$$

Section 4 . The erosional velocity approach which used by [Aghabarati et al., \(2008\)](#) for modeling sand production:

$$-\frac{\partial p}{\partial t} + \nabla \cdot [(1 - \phi) \dot{U}_s] + \frac{\dot{m}}{\rho_s} = 0 \quad (11)$$

$$-\frac{\partial [\phi (S_{fs} - 1)]}{\partial t} + \nabla \cdot [\eta_{slip} S_{fs} V_m + (1 - \phi + S_{fs}) \dot{U}_s] = 0 \quad (12)$$

$$\frac{\dot{m}}{\rho_s} = \lambda(\varphi_{\max} - \varphi)S_{fs}\left(1 - \frac{S_{fs}}{S_{fsc}}\right)\|V_m\|\text{if}\|V_m\| \geq \|V_m^{Cr}\| \quad (13)$$

$$\frac{\dot{m}}{\rho_s} = 0 \text{ if } \|V_m\| < \|V_m^{Cr}\| \quad (14)$$

Section 5 . Kinetic reactions of fluid PVT behavior treatment that Rivero et al., (2010) used in their model:

1. $[g_d] \rightarrow [b_d]$, 2. $[g_d] + [b_d] \rightarrow 2[b_d]$, 3. $[b_d] \rightarrow [b_c]$, 4. $[g_d] + [b_d] \rightarrow 2[b_c]$

$[g_d]$ is dissolved CH_4 gas oil phase

$[b_d]$ is dispersed CH_4 gas bubbles in oil phase

$[b_c]$ is connected CH_4 gas bubbles in gas phase (free gas)

$$r_d^{(1)} = A_1(c_{gd} - c'_{gd}) \quad (15)$$

$$r_d^{(2)} = A_2(c_{gd} - c'_{gd})^2(c_{bd}) \quad (16)$$

$$r_c^{(3)} = B_1(c_{bd}) \quad (17)$$

$$r_c^{(4)} = B_2(c_{gd} - c'_{gd})^2(c_{bd}) \quad (18)$$

$r_d^{(1)}$ and $r_d^{(2)}$ are rates of transfer of dissolved gas into dispersed bubbles for reactions 1 and 2, respectively. $r_c^{(3)}$ and $r_c^{(4)}$ are transfer rates of dissolved gas and dispersed bubbles into continuous bubbles for reactions 3 and 4, respectively. c_{gd} is concentration of the dissolved gas. A_1 , A_2 , B_1 and B_2 are transfer coefficients.

$$c_{gd} = \Phi S_o \rho_o x_{gd} \quad (19)$$

S_o is oil saturation, ρ_o is oil density, Φ is porosity and x_{gd} is mole fraction of the dissolved gas.

$$c'_{gd} = \Phi S_o \rho_o x'_{gd} \quad (20)$$

$\dot{c}_{gd}$ is equilibrium concentration of the dissolved gas and $\dot{x}_{gd}$ is equilibrium mole fraction of the dissolved gas.

Section 6 . Non-linear diffusion equation for pressure (Eq. 23) and foamy oil and sand flow equations (e.g. oil and sand velocity (Eqs. 21, 22) and foamy oil viscosity (Eq. 26)) which Vanderheyden et al., (2013) used in their methodology:

$$\theta_o u_o = -K_o \varphi \frac{k_o}{\mu_o} \nabla_p \quad (21)$$

$$\theta_s u_s = -K_o \varphi \frac{k_s}{\mu_o} \nabla_p \quad (22)$$

$$\frac{\partial p}{\partial t} + u_o \cdot \nabla_p = \frac{c_o^2 \rho_o}{\theta_o} \nabla \cdot \left(K_o \varphi \frac{k_o + k_s}{\mu_o} \nabla_p \right) + c_o^2 \rho_o \left(1 - \frac{\rho_g}{\rho_l} \right) \left(\frac{\partial S_g}{\partial t} + u_o \cdot \nabla S_g \right) \quad (23)$$

$$\rho_o = (1 - S_g) \rho_l + S_g \rho_g \quad (24)$$

$$\frac{1}{c_o^2 \rho_o} = \frac{1 - S_g}{c_l^2 \rho_l} + \frac{S_g}{c_g^2 \rho_g} \quad (25)$$

$$\mu_o = \mu_l (1 - S_g)^{-2} \quad (26)$$

$$\theta_o \rho_o \frac{du_o}{dt} = -\theta_o \nabla_p + \nabla \cdot (\theta_o \sigma_\nu) - \theta_o \theta_s f_{so} \quad (27)$$

$$\theta_s \rho_s \frac{du_s}{dt} = -\theta_o \nabla_p + \nabla \cdot [\theta_s (\sigma_\nu + pI)] + \nabla \cdot (\theta_s \sigma_\nu) + \theta_o \theta_s f_{so} \quad (28)$$

Section 7 . Mass conservation equations which used by Wang et al. (2001.) in their geomechanics/reservoir coupling approach:

$$\frac{d\varnothing_s}{dt} + \nabla m_s + q_s = 0 \quad (29)$$

$$\frac{d\varnothing_j}{dt} + \nabla m_j + q_j = 0 \quad (30)$$

$$\frac{\partial[(1 - \varnothing)\rho_s]}{\partial t} + [\nabla(1 - \varnothing)\rho_s V_s] + q_s = 0 \quad (31)$$

$$\frac{\partial[S_j \varnothing \rho_j]}{\partial t} + [\nabla S_j \varnothing \rho_j V_j] + q_j = 0 \quad (32)$$

$$s_g + s_w + s_o = 1 \quad (33)$$

The equation of fluid motion:

$$u_j = s_j \phi (v_j - v_s) = -\frac{kk_{rj}}{\mu_j} \nabla P_j \quad (34)$$

Mass conservation for the fluid phase in Eq. 32 can be expressed as:

$$\frac{\partial [s_j \phi \rho_j]}{\partial t} - \nabla \cdot \rho_j \left(\frac{kk_{rj}}{\mu} \cdot \nabla P_j \right) + V_s \cdot \nabla (s_j \phi \rho_j) + s_j \phi \rho_j \nabla V_s + q_j = 0 \quad (35)$$

The above equation can be simplified as:

$$s_j \frac{\partial \varepsilon_v}{\partial t} + \phi \frac{\partial s_j}{\partial t} + C_j \phi s_j \frac{\partial P_j}{\partial t} - \nabla \cdot \left(\rho_j \frac{kk_{rj}}{\mu} \nabla P_j \right) + q_j = 0 \quad (36)$$

$$\nabla V_s = -\frac{1}{(1-\phi)\rho_s} \frac{d((1-\phi)\rho_s)}{dx} = \frac{\partial \varepsilon_v}{\partial t} \quad (37)$$

The conventional mass conservation equation employed in most reservoir simulators is given by:

$$\frac{\partial (\phi \rho_j s_j)}{\partial t} - \nabla \cdot \left(\rho_j \frac{kk_{rj}}{\mu} \nabla P_j \right) + V_s \cdot \nabla (\rho_j \phi s_j) = 0 \quad (38)$$

Section 8 . In their 2004 study, Liu et al., used the diffusivity equation—formulated from the continuity relationship and Darcy's law—to describe the unsteady three-dimensional movement of a slightly compressible fluid through a homogeneous, anisotropic porous formation.

$$k_x \frac{\partial^2 p}{\partial x^2} + k_y \frac{\partial^2 p}{\partial y^2} + k_z \frac{\partial^2 p}{\partial z^2} = \phi \mu C_t \frac{\partial p}{\partial t} \quad (39)$$

The corresponding dimensionless pressure is expressed as:

$$P_D = \frac{2\pi kh}{q_c \mu B} [p_o - p(xyzt)] \quad (40)$$

The corresponding dimensionless time is expressed as:

$$t_D = \frac{k_t}{\mu \phi C_t L_r^2} \quad (41)$$

And the corresponding dimensionless distances and height are expressed as:

$$x_D = \frac{x}{L_r} \sqrt{\frac{k}{k_x}} \quad (42)$$

$$y_D = \frac{y}{L_r} \sqrt{\frac{k}{k_y}} \quad (43)$$

$$z_D = \frac{z}{L_r} \sqrt{\frac{k}{k_z}} \quad (44)$$

$$h_D = \frac{h}{L_r} \sqrt{\frac{k}{k_z}} \quad (45)$$

$$\frac{\partial^2 P_D}{\partial x_D^2} + \frac{\partial^2 P_D}{\partial y_D^2} + \frac{\partial^2 P_D}{\partial z_D^2} = \frac{\partial P_D}{\partial t_D} \quad (46)$$

Section 9 . Darcy's law flow equations that Han et al., (2004) used in their sanding model:

$$-\frac{\partial P}{\partial r} = \frac{\mu}{k} \phi (V_f - V_s) \quad (47)$$

$$V_f = -\frac{q}{2\pi r \phi} \quad (48)$$

$$V_s = -\frac{q_s}{2\pi r(1-\phi)} \quad (49)$$

Combining these results in:

$$-\frac{\partial P_p}{\partial r} = \frac{\mu}{2\pi k} \left(q - \frac{\phi q_s}{1-\phi} \right) \frac{1}{r} \quad (50)$$

Darcy's equation in the term of the mass rate (m_f):

$$m_f = \frac{2\pi k \rho_{fsat} r}{\mu(1+B_f)P_{sat}^{B_f}} \frac{dP_e^{(1+B_f)}}{dr} \quad (51)$$

By assuming a constant mass rate and integrating with respect to r from R_c to R_2 , the following expression is obtained:

$$\frac{m_f}{\rho_{fsat}} = \frac{2\pi k}{\mu(1+B_f)\ln(R_2/R_c)} \frac{P_2^{(1+B_f)} - P_c^{(1+B_f)}}{P_{sat}^{B_f}} \quad (52)$$

The expression on the left side of the equation corresponds to the volumetric flow rate, q_{sc} , normalised by the formation thickness. This representation is valid because the oil density at saturation pressure, ρ_{fsat} , is effectively comparable to the density observed under surface conditions, allowing the term to be interpreted as the surface volumetric production rate.

Section 10 . Two kinetics equations in the foamy oil models that Pan et al., (2010) used to designate the mass transfer:

$$X_1 = F_1 * ([SOLG]_{equilibrium} - [SOLG]) \quad (53)$$

$$X_2 = F_2 * [DISPG] \quad (54)$$

X_1 denotes the mass transfer rate associated with the release of gas from the dissolved phase into the dispersed gas phase.

X_2 represents the subsequent transfer rate by which dispersed gas coalesces and evolves into the free gas phase.

$[SOLG]$ refers to the concentration of gas remaining dissolved in the liquid phase, while $[SOLG]_{equilibrium}$ indicates the dissolved gas concentration corresponding to thermodynamic equilibrium conditions.

$[DISPG]$ describes the concentration of gas present as dispersed bubbles within the fluid.

Section 11. Gassmann's relations that Riazi et al., (2014) used in their rock physics modeling:

$$V_{P1} = \sqrt{\frac{k + \frac{4}{3}\mu}{\rho}} \quad (55)$$

$$V_{S1} = \sqrt{\frac{\mu}{\rho}} \quad (56)$$

The equations presented above establish the basic relationships that define the initial seismic wave velocities within the medium. In this context, V_{P1} and V_{S1} correspond to the primary (P-wave) and shear (S-wave) velocities in their initial state, while K and μ denote the corresponding bulk and shear moduli of the rock framework. Using these parameters, the bulk modulus of the fluid-saturated rock, K_{sat} , can subsequently be evaluated through the Gassmann formulation.

$$K_{sat} = K_{dry} + \frac{(1 - \frac{K_{dry}}{K_m})^2}{\frac{\Phi}{K_f} + \frac{1-\Phi}{K_m} - \frac{K_{dry}}{K_m^2}} \quad (57)$$

In this formulation, Φ denotes the porosity of the rock. K_{dry} refers to the bulk modulus associated with the dry rock framework, K_f represents the bulk modulus of the fluid occupying the pore space, and K_m corresponds to the bulk modulus of the solid mineral matrix composing the rock.

Section 12. To obtain heavy oil properties, Riazi et al., (2014) used the equations of Btazle and Wang in their rock physics modeling, which are dependent on temperature, API, GOR and pressure of the hydrocarbon:

$$V_{P_sat} = \sqrt{\frac{k_{sat} + \frac{4}{3}\mu_{sat}}{\rho_{sat}}} \quad (58)$$

$$V_{S_sat} = \sqrt{\frac{\mu_{sat}}{\rho_{sat}}} \quad (59)$$

Here, V_{P_sat} and V_{S_sat} denote the saturated P-wave and S-wave velocities, respectively.

Data availability

Data will be made available on request.

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