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Review

Formation Damage in SAGD: A Review of Experimental Modelling Techniques

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Abstract: Bitumen extraction using Steam-Assisted Gravity Drainage (SAGD) in northern Alberta oilsands has been crucial for recovery; however, the thermal effects on formation damage still require significant attention. This thermal recovery method causes substantial changes in temperature and pressure, which are critical thermodynamic factors in the rock-fluid system of a reservoir. Those changes, both directly and indirectly, impact the flow of oil and water within the porous medium, changing fluid properties and physicochemical interactions that affect rock and fluid behaviour. Coreflooding experiments confirm the accumulation of in situ migratory particles within the pore spaces can lead to pore throat plugging and fines accumulation on the sand control screen. This disturbance within the near-wellbore region triggers permeability reduction and, subsequently, skin buildup. At the same time, changes in pressure drop may trigger the precipitation of organic and inorganic scaling and, finally, wettability alterations. This paper combines field observations and experimental tests to assess the formation damage mechanisms. While the literature has identified factors influencing the formation damage mechanisms, the interaction between these mechanisms, as well as the interplay between the wellbore completion and the surrounding sand from the perspective of formation damage, has not been thoroughly investigated. Current laboratory tests do not adequately account for the effects of high pressure and high temperature on formation damage mechanisms and their interaction in the near-wellbore region. Following the introduction of current experimental and theoretical methods related to formation damage mechanisms around SAGD wellbores, this paper introduces a comprehensive and integrated methodology for designing, testing, and evaluating formation damage mechanisms in SAGD producer wells, addressing the gaps identified in this review. This approach aims to bridge identified gaps from the literature review, advance formation damage assessment, and support the reduction of induced formation damage in thermal recovery operations.

Keywords: SAGD; oilsands; fines migration; organic deposition; inorganic scaling; mineral transformation; wettability alteration

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1. Introduction

The province of Alberta is where most of the oilsands deposits are located in Canada, consisting of approximately 95% of the bitumen in the Athabasca, Cold Lake, and Peace River sand deposits [1]. Oilsands production from Western Canada (4.37 million b/d in 2018) can be recovered either by surface mining in shallow resources or in situ recovery processes for deeper deposits. The oilsands surface mining area in Alberta currently corresponds to 953 square kilometres, and an additional 3847 square kilometres can be exploited economically by in situ projects [1].

In oilsands in situ recovery techniques, the critical factor for enabling oil production to the surface is the reduction of viscosity. For instance, the viscosity of Athabasca bitumen decreases significantly with increasing temperature [2]. Thermal Enhanced Oil Recovery (EOR) processes, therefore, aim to enhance oil mobility by elevating the temperature of the bitumen. Among these processes, SAGD stands out as a prominent method. In the SAGD process, steam generated on the surface is injected into the reservoir through a horizontal well positioned approximately 5 m above a horizontal producer well near the oilsands bed. This high-temperature steam raises the pressure in the steam chamber, delivering latent heat to the bitumen at the chamber's periphery around the injector. As the viscosity of the bitumen is decreased, it flows under the force of gravity into a liquid pool around the producer well, where it is subsequently extracted and pumped to the surface [3,4]. This method capitalises on the natural properties of bitumen and the reservoir to achieve efficient and sustained recovery.

The SAGD recovery technique, however, can significantly and permanently reduce reservoir permeability due to interactions between the injected fluids and the reservoir rock, especially in formations with high clay content and poor consolidation [5]. As bitumen is extracted from unconsolidated oilsands, SAGD wells are susceptible to sand production, making it essential to use sand control devices to prevent solids from entering the wellbore. The SAGD technique relies on the high-pressure steam injection into the reservoir rock, triggering complex thermal and hydraulic processes regarding fluids and rock interactions [6], which can provoke formation damage mechanisms that hinder oil production. These mechanisms are often identified through indicators such as a gradual increase in the pressure differential between injection and production wells, which can exceed 1000 kPa in some cases [7]. Similarly, an abnormal decline in production rates beyond what is typically expected is another sign of severe formation damage [7,8].

The effectiveness of the SAGD process largely depends on fluid mobility; therefore, SAGD requires significant amounts of water for steam production and considerable natural gas to generate the necessary heat [9]. As a result, the energy demands of SAGD are quite substantial and can be even higher by the severity of the effect of caused obstructions in the flow path [10].

This paper provides a comprehensive review of current experimental and theoretical methods related to formation damage mechanisms around SAGD wellbores. Thermal recovery methods influence fluid properties [11], interactions between fluids and solids [12], and flow dynamics within the porous medium [13], leading to issues including near-wellbore pore throat and sand control device plugging by fines migration [14], organic deposition [15], inorganic scaling [16], mineral transformation [17], and wettability alteration [18], which ultimately reduce permeability and alter the pressure differential between the injection and production wells [12]. While several studies [5–8] have explored these formation damage mechanisms individually, the complex interactions between them, wellbore completion, and the surrounding sand have not been thoroughly investigated. Existing laboratory tests often fail to replicate the high-pressure and high-temperature conditions found in the near-wellbore region, as well as potential interactions between these mechanisms (Figure 1). This paper summarises existing research, identifies knowledge gaps, and proposes a comprehensive procedure for designing formation damage tests to address these gaps and guide future research.

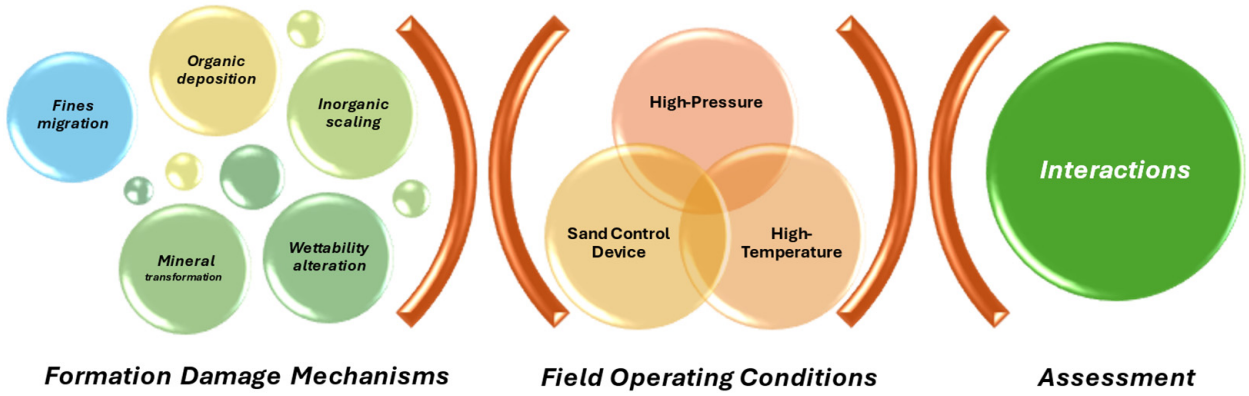


Figure 1. Review process summary.

2. Formation Damage Mechanisms in SAGD

Oilsands reservoirs are susceptible to various formation damage mechanisms influenced by their shallow, unconsolidated, and poorly sorted nature [10]. The inherent geomechanical weakness of these reservoirs necessitates continuous sand control efforts, as sand production remains a persistent challenge [14]. Beyond sand control, these reservoirs are also vulnerable to several other damage mechanisms, including fines migration, paraffin and asphaltene deposition, various forms of scaling, and clay swelling [10]. In thermal EOR processes, additional complications arise from the dissolution and alteration of the oilsands formation [9]. Despite the relatively high permeability of oilsands reservoirs, formation damage can still lead to sub-optimal production if not properly managed [5].

The complexity of formation damage in oilsands reservoirs is further exacerbated by the methods employed for exploitation [19–22]. Devices such as standalone sand screens are crucial for sand control but are also prone to plugging from various formation damage mechanisms [5]. Over time, these protective measures can become clogged, leading to a significant reduction in inflow, an increase in pressure differential [23], and ultimately, detriment in overall well performance [8].

Each formation damage mechanism introduced in the remainder of this section can independently or synergistically impair reservoir productivity. Therefore, it is crucial to implement measures to prevent, manage, or mitigate this critical aspect of heavy oil recovery operations, ensuring that the economic potential of thermal recovery methods, such as SAGD, is fully realised.

2.1. Fines Migration

Among different causes of formation damage in oilsands reservoirs, fines migration is considered a major issue as it leads to pore throat plugging around SAGD production wells [13,24–29]. In fines migration, small particles are released from pore surfaces, transported, and captured (deposition) in thin pore throats around the wells, where pressure drops and local permeability impairment occur [30] or deposited where flow restrictions are placed (i.e., sand control systems). This phenomenon is driven by a combination of hydrodynamic and physicochemical forces [13]. Several studies have explored the dynamics of fines migration [30–32]. The mobilisation of fines is influenced by rupturing the equilibrium between attaching forces, including van der Waals forces and gravity and detaching forces, such as electrical double-layer forces, drag, and lift, which are, in turn, affected by parameters such as salinity, pH, velocity, and temperature [9,13,20,25,26,28,30,32].

In any production operation, the reservoir undergoes a sequence of changes ranging from physicochemical, chemical, hydrodynamic, thermal, mechanical, and biological [13] that inevitably alter rock and fluid properties, potentially affecting the release of fines.

During thermal EOR, heat factor is highly relevant as it amplifies the effect of fines migration, which, in turn, may generate other mechanisms [10,31].

Different influential factors in the fines migration process are presented (Figure 2), grouping the key factors into five categories: (1) factors related to the porous medium structure, (2) factors related to fines present in the porous media, (3) factors concerning to the carrier fluid, (4) environmental factors (such as temperature), (5) factors related to well operation, and (6) factors related to well completion. Some factors are broadly applicable, while others are specific to thermal recovery in unconsolidated oilsands. The impact of these factors has been explored through numerous coreflood experiments, primarily on homogeneous Berea sandstone cores [18,19,26,28,31–34].

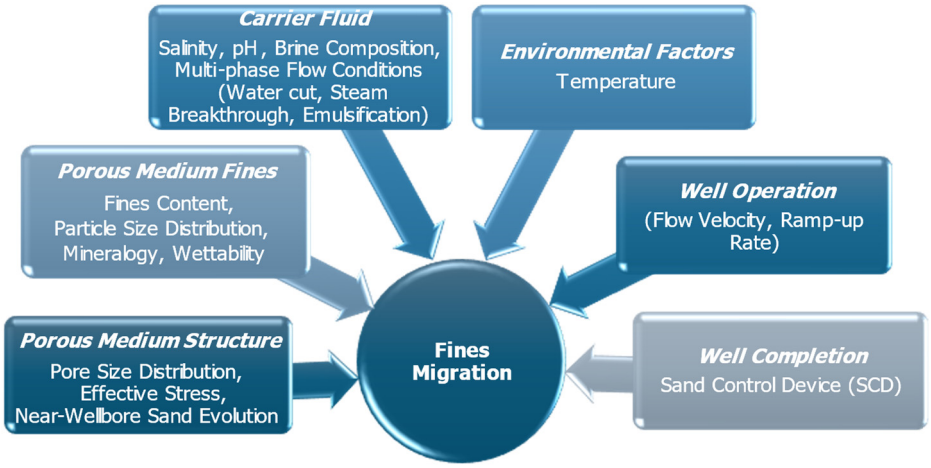


Figure 2. Influential factors in fines migration.

Additionally, several flow tests have been performed on unconsolidated sand packs using synthetic or natural sands [26,28,32,35–39]. These tests examined various scenarios, including stepwise increases in flow rate, gradual reductions in salinity, and single-phase and multi-phase flow involving polar oil, non-polar oil, and solvents. Fines migration was assessed by measuring effluent fines production and changes in permeability within the core plugs and sand packs [29,40].

The impact of salinity on fines migration is notably influenced by temperature variations [41]. At elevated temperatures, repulsive electrical forces become more pronounced, leading to an increased release of fines from pore surfaces, which consequently reduces permeability [42]. Operational factors also play a significant role in fines migration, through flow velocity [26,40,43], water-cut [14,44], and the production ramp-up rate [7,40]. These factors influence the drag and lift forces acting on fine particles. Additionally, the characteristics of the fines and pores—such as pore and fines size distribution, fines content, fines mineralogy, and wettability—further complicate the migration process [14,32,44,45]. The design of sand control systems also affects whether fines pass through or become trapped around the sand control screen [26].

2.2. Organic Deposition

Most heavy oils and bitumen are characterised by substantial asphaltene content, sometimes reaching levels as high as 22 wt% [46]. Initially, these asphaltenes remain in solution under reservoir conditions involving specific pressure, temperature, and composition. However, alterations in those conditions such as composition changes due to diluent addition cause precipitation and subsequent deposition of asphaltenes within the reservoir. This results in an on-site enhancement of heavy oil, yielding a lighter-produced oil [47]. Nevertheless, the propensity for asphaltene deposition extends beyond diluent-

induced changes and encompasses factors such as pressure and temperature fluctuations. Such depositions impede permeability in the vicinity of the wellbore [48].

Although there is a potential desire for in situ asphaltene precipitation to enhance the quality of the produced oil, the cost of mitigating issues linked with asphaltene precipitation in the porous medium around the production well, as well as inside production lines, and petroleum processing and transportation facilities is high. It is crucial to acknowledge that in situ asphaltene precipitation could adversely impact oil flow around the wellbore by diminishing the oilsands' porosity and permeability [49].

The extent of permeability loss due to organic deposition is influenced by factors such as rock type, oil composition, solvent type and concentration, and pressure and temperature shift [50]. High production rates may exacerbate formation damage as well by intensifying the driving forces for asphaltene particle migration and capture [50].

2.3. Inorganic Scaling

Scaling in SAGD operations predominantly manifests as deposits of silicates and carbonates, stemming from the migration of ions present in the formation into condensed water draining towards the production well [7,8]. The formation of carbonate scales is attributed to reactions taking place at elevated temperatures involving divalent ions and bicarbonate ions (HCO_3^-), carbonates (CO_3^{2-}), or even CO_2 dissolved in water [5]. These scales tend to accumulate around production wells, causing significant pressure differentials between the injector and producer wells [8,12,51] and affecting oil production.

Calcium carbonate scaling, abundantly predominant in SAGD wells, is a prominent concern, primarily linked to the pressure differentials experienced across liner slots. As reservoir fluids, in tandem with condensed steam, flow through these slots, the resultant pressure drop may trigger the liberation of CO_2 from the solution [52].

At steam chamber temperatures, typically above 200 °C, another reaction known as aquathermolysis occurs, catalysed by the interaction of hot water with bitumen, resulting in the liberation of H_2S. This hydrogen sulphide reacts with iron, forming iron sulphide, which deposits within the slots [53]. The accumulation of scale within the liner slot triggers an escalation in pressure drop, aggravating the condition. As time progresses, the liner slot may gradually become obstructed by scale, leading to alterations in key well attributes such as temperature, pressure, and overall fluids production [8].

Silicate scaling arises from the interplay between hot steam injection and the porous medium, particularly rich in silicate minerals such as quartz and feldspar, owing to the abundant presence of silicate ions in the reservoir fluids [51]. Previous research underscores the significance of salinity, pH, flow rate, and temperature as pivotal factors influencing the decline in permeability due to scale deposition around thermal wells [5].

2.4. Mineral Transformation

Mineral transformation is a significant process that can profoundly affect reservoir properties under SAGD conditions. Notably, the metamorphic transformation of feldspar to kaolinite and, subsequently, kaolinite to smectite occurs when these minerals are exposed to high-temperature steam [7]. In a SAGD pilot project, petrographic analyses conducted before and after steam injection revealed the emergence of smectite, a swelling clay, in core samples from a formation that initially did not contain smectite [7,31,54]. This transformation indicates a substantial alteration in the mineralogical composition of the reservoir rock due to thermal conditions.

Kaolinite exhibits dual forms of formation impairment, each culminating in alterations to permeability. At lower temperatures, kaolinite facilitates fines migration, while during elevated temperatures, it undergoes reactions with surrounding minerals and condensed

steam, resulting in the formation of smectite or analcime [54]. At temperatures surpassing around 180 °C, inert clay species could undergo catalysis, generating hydratable reactive substances that might induce swelling, dispersion, and subsequently decrease permeability [31]. These transformations become particularly significant at temperatures exceeding 250 °C [10].

2.5. Wettability Alteration

Wettability is altered during most oil recovery processes [55], which has implications for key reservoir characteristics such as relative permeability and residual saturation [56], thereby directly influencing oil recovery rates. The transition in wettability, particularly around the wellbore, from a water-wet to an oil-wet state is likened to the presence of a semipermeable membrane surrounding the wellbore. This transition tends to facilitate the passage of water while impeding the flow of oil, resulting in detrimental consequences such as flow obstruction and an undesirable rise in the water-oil ratio during production [10].

Different factors may induce rock wettability changes, such as the adsorption of heavy polar constituents of oil, inorganic precipitates, and mineral transformation [57,58]. Asphaltene deposition can progressively shift water-wet rocks to oil-wet [59–61] or mixed-wet states [62], reducing oil-relative permeability and worsening wellbore plugging, which complicates reservoir management [63]. Interestingly, wettability itself plays a role in regulating asphaltene deposition, creating a bidirectional interaction where deposition influences wettability and vice versa [64].

In most cases, formations tend to exhibit increased water-wettability with rising temperatures by reducing the adsorption of polar materials on rock surfaces [65–67]. Water wettability is advantageous for heavy oil recovery, as it facilitates improved oil displacement and flow. However, contrary observations exist where rock wettability rapidly transitions from strongly water-wet to strongly oil-wet under prolonged steam injection [68]. In some instances, introducing superheated steam to formations prompts shifts towards oil-wet behaviour [10]. While polarity resulting from the water and asphaltenes in porous media plays a pivotal role in wettability alteration, the presence of surface charges on components may also influence wettability [69–71].

The interaction between clays and asphaltenes, and, more broadly, with polar oil groups, is attributed to the oil-wet nature of fines [49]. This association of asphaltenes with clays modifies the reservoir wettability towards a more oil-wet state [59]. As the injection of steam persists, there is a decline in oil saturation [72], prompting a transition towards water-wet conditions. Nonetheless, conflicting views suggest a surge in oil wetness with steam propagation [57,68]. This inconsistency might stem from interactions between high-molecular-weight oil constituents and rock, inducing a shift from water-wet to oil-wet conditions [59].

Furthermore, the type of clay exerts a notable influence on wettability modification, with clay alteration and migration potentially amplifying this effect [68]. Asphaltenes are typically defined as the fraction of crude oil that is insoluble in normal alkanes (such as n-pentane or n-heptane) but remains soluble in aromatic solvents [73]; therefore, under solvent injection processes in oilsands (such as VAPEX, SA-SAGD, and ES-SAGD, to mention some) asphaltene precipitation becomes an enormous phenomenon directly influenced by the solvent's composition [58]. If asphaltene-soluble solvents are present in the injected current, the asphaltenes are expected to remain solubilised and be carried with the produced bitumen. However, when using asphaltene-insoluble solvents, asphaltenes will precipitate within the reservoir.

3. Experimental Modelling of Formation Damage

Plugging materials include fines [74], organic deposits [75–78] and inorganic scales [79], contributing to significant permeability reductions. At the same time, mineralogical changes [75] and wettability alterations [80] contribute to hindering flow.

Experimental modelling of formation damage in SAGD plays a crucial role in understanding the mechanisms that affect reservoir performance during thermal recovery processes. By simulating field conditions in controlled laboratory environments, these studies allow for the investigation of fluid-rock interactions, the impact of thermal and chemical processes, and the identification of potential damage sources. The results from these experiments provide essential data for matching mathematical models.

Different tests utilising cores and pre-packed sand have been conducted to quantify plugging through a parameter called retained permeability, which is the ratio of the permeability of the combined screen and adjacent sand pack to the initial permeability before testing [81]. In these experiments, screen plugging occurs when plugging materials adhere to and obstruct the screen slots, while pore plugging results from materials accumulation within the sand pack immediately surrounding the screen [82]. The remainder of this section reviews experimental studies that have investigated these plugging factors.

3.1. Fines Migration

Fine particles are microscopic, loose grains in the reservoir, typically consisting of clay minerals such as kaolinite, illite, smectite, and chlorite, as well as non-clay minerals such as quartz, silica, feldspar, calcite, and dolomite [44]. Initially, fine particles adhere to larger grains due to a combination of net attractive surface forces and gravity but are susceptible to migration [83].

Notably, fine-particle denudation can have beneficial effects in some cases. For example, Xu et al. [66] used Scanning Electron Microscopy (SEM) to examine pore structures before and after steam injection. Their observations revealed that steam flow smoothens uneven pore walls previously covered with small particles, leading to a significant increase in rock permeability—over 300% in some cases. Furthermore, direct visual evidence of changes in pore structures highlights the substantial effects of thermal fluid flow on pore morphology [84].

The rest of this section presents an in-depth examination of fluid and flow characteristics, as well as environmental conditions and their impact on reservoir permeability. It explores critical factors such as pH, flow velocity, salinity, viscosity, and temperature and how these influence fines migration, dispersion, and subsequent permeability alterations under various subsurface conditions.

3.1.1. Fluid Characteristics

Core experiments conducted under varying pH conditions reveal that high-pH fluids can significantly reduce rock permeability at equivalent flow rates. This is attributed to the interaction between high-pH fluids and fines minerals, which generates more dispersed particles [85–88], facilitating particle migration within pore spaces [5]. Additionally, alkaline fluids have been reported to promote the transport of fine particles, further amplifying the risk of formation damage [89–94].

Salinity mismatches between injected fluids and formation water are another key driver of fine particle dispersion and migration. A discrepancy in salinity levels can destabilise the formation and intensify particle migration, leading to significant permeability impairment [95]. In contrast, the viscosity of crude oil, another critical fluid property, directly affects particle transport. Experiments by Zhong et al. [84] using sand pack models demonstrated that high-viscosity crude oils can mobilise sand particles effectively, forming visible wormholes at the outlet of the sand pack. Furthermore, these experiments showed

a notable increase in rock permeability with rising crude oil viscosity. However, this relationship appears to have an upper limit, suggesting that permeability gains may plateau beyond a certain viscosity threshold.

3.1.2. Fluid Flow Characteristics

The flow velocity of reservoir fluids is widely regarded as one of the most critical factors influencing the erosion and migration of fine particles during reservoir operations, as tested by Liu et al. [96]. To characterise the conditions under which significant permeability reductions occur due to fine particle migration, the concept of critical flow velocity is widely employed. This key parameter defines the threshold at which the flow velocity of fluids in the pore space surpasses the critical value, initiating the erosion and mobilisation of fine particles [44]. At velocities exceeding this threshold, fine particles are stripped from the pore walls and carried downstream. Conversely, as flow velocity decreases, these suspended particles redeposit within the pore spaces, forming aggregates that lead to sand clogging and a pronounced decline in permeability, particularly in the clogging zones [81]. This phenomenon, commonly called velocity sensitivity, is a well-recognised form of reservoir damage during oil and gas recovery [29]. However, existing studies have predominantly focused on the regions of particle redeposition and their impact on permeability, often overlooking the regions where fine particles are initially stripped [97].

A study on fines migration and permeability [98] investigated the effects of fluid flow rates on fines migration using cores and sand packs under triaxial loading. Variations in flow rates revealed that higher velocities increased fines detachment and mobilisation, leading to permeability reductions due to pore blockage. Reverse flow was tested to address plugging, highlighting the significant role of flow dynamics in fines redistribution within porous media.

3.1.3. Environmental Conditions

In addition to fluid properties, formation characteristics such as effective stress and thermal fluid temperature directly influence fine particle migration and subsequent changes in rock permeability. Experimental evidence suggests that the reduction in rock permeability accelerates with increasing thermal fluid temperatures, even when salinity levels remain constant [5]. Effective stress also plays a role, particularly in determining the critical velocity required for particle mobilisation. Research by Coşkuner and Maini [99] demonstrated that critical velocity decreases as net confining pressure increases. This is likely due to the narrowing of pore throats under elevated stress conditions, making smaller pores more susceptible to blockage by migrating fine particles at identical flow rates. Data from this research further highlights that critical velocity varies significantly across formations and is inversely proportional to net confining pressure.

A study on Cold Lake oilsands [9] demonstrated that elevated temperatures significantly intensified fines migration, leading to permeability reductions. Permeability decreased from 1100 mD to 580 mD at 66 °C and, further, to 175 mD at 149 °C, primarily due to fines deposition in pore throats, highlighting the critical role of temperature in exacerbating fines-related formation damage.

3.2. Organic Deposition

This section reviews key experimental studies that provide insight into asphaltene flocculation, deposition behaviours, and associated permeability impairment in reservoir rocks. Laboratory tests by Leontaritis et al. [49] demonstrated that asphaltene flocculation is a rapid, erratic process involving significant micelle rearrangement. During flocculation, asphaltene micelles, initially 2–35 nm in size, form larger particles exceeding 100 nm (0.1 μm), as confirmed by filtration measurements. This size increase is critical for permeability impairment, with more severe flocculation producing higher concentrations of these large

particles. Within reservoir rocks, flocculated asphaltenes reduce porosity and permeability by settling in pores [100] or bridging at pore throats [101,102], obstructing fluid flow [103]. Experimental titrations with flocculants such as n-hexane highlight the adverse effects of asphaltene precipitation, where large particles clog pore spaces and disrupt fluid pathways.

Mukhametshina et al. [104] investigated asphaltene deposition in porous media during solvent injection using toluene (asphaltene-soluble) and n-hexane (asphaltene-insoluble) under conditions of 75 psig and 165 °C. The study revealed that certain solvents destabilise asphaltenes, causing precipitation in production lines and porous media. Fluid testing confirmed significant asphaltene-related plugging, and a highly consolidated sand sample retrieved from the cell indicated extensive deposition within the rock pore structure.

Hamadou et al. [105] conducted experiments to assess formation damage caused by asphaltene deposition using core samples from Berea sandstone. Their findings revealed a substantial reduction in permeability, with losses ranging from 72.4% to 98.3%. Furthermore, their results demonstrated a notable correlation between the iron content of the rock samples and permeability reduction. The study suggested that higher iron content decreases the apparent hydrophobicity of the rocks, thereby reducing asphaltene deposition.

3.3. Inorganic Scaling

The mechanisms underlying formation damage caused by mineral precipitation share similarities with the effects of fines migration on rock permeability. Both processes involve fine solids generated from chemical reactions. While mineral dissolution is negligible at low-temperature and neutral-pH conditions [79], high-temperature and high-pH environments during thermal recovery can significantly intensify chemical reactions, promoting mineral dissolution [106,107]. The dynamic variations in temperature and pH during thermal fluid injection further complicate the process. These variations differ across reservoir regions [108], resulting in mineral dissolution in high-temperature, high-pH zones and reprecipitation in lower-temperature, lower-pH zones. This redistribution of minerals inevitably alters the permeability profile of the reservoir.

Experimental research by Reed [109] establishes a correlation between silica (Si) dissolution and both temperature and pH, demonstrating that sandstone dissolves more readily under high-temperature, high-pH conditions. Conversely, a negative correlation between Si dissolution and fluid injection rate is defined as higher flow rates reducing interaction time between thermal fluids and rock. Lower flow rates allow prolonged interaction, enhancing dissolution effects.

Krauskopf and Bird [110] examined quartz and amorphous silicon dissolution in pure water at varying temperatures. McCorriston et al. [93] analysed quartz dissolution in NaOH solutions under different temperature and pH conditions. Pang et al. [59,111] separately investigated the solubility of sandstone and clay minerals in fluids with varying temperatures and pH. Across these studies, a consistent trend emerges: silica solubility increases with both temperature and pH; however, significant discrepancies in the reported solubility values highlight the influence of experimental conditions and rock sample characteristics.

Other research works have reported the detrimental effects of high-pH fluids on reservoir permeability. McCorriston et al. [93] investigated this phenomenon by preparing steam boiler condensate and alkaline solutions with pH values ranging from 7.0 to 12.5. By injecting these fluids into sandstone cores, they observed a noticeable reduction in permeability upon contact with condensate water. This finding highlights the potential of high-pH fluids to damage rock permeability. However, the underlying mechanisms extend beyond mineral dissolution and precipitation.

Okoye et al. [5,112] expanded upon these findings by injecting Berea sandstone cores—either water-saturated or heavy-oil saturated—with 0.5%, 1.0%, and 2.0% NaOH solutions.

Their experiments, conducted under both positive and reverse injection scenarios, demonstrated significant permeability reduction at high pH levels and elevated temperatures. Importantly, reverse injection failed to completely restore permeability, underscoring the presence of additional factors beyond particle migration that influence petrophysical properties. Furthermore, their results showed no significant correlation between the type of saturated fluid and the extent of rock damage caused by alkaline substances.

In a subsequent study, Okoye et al. [113] explored the impact of NaOH solutions on rock porosity. They found that porosity loss was directly related to the concentration of the NaOH solution, the duration of the reaction, and the experimental temperature. These findings suggest that alkaline-induced damage to reservoir rock is not only a function of pH but also influenced by the chemical interactions between the fluid and the rock matrix over time. Collectively, these studies emphasise the complexity of formation damage caused by high-pH fluids, where multiple factors—ranging from chemical reactions to particle migration—converge to alter reservoir properties.

A study on Berea sandstone cores [5] evaluated scaling and permeability damage during high-pH water (steam) injection. The cores, with an average air permeability of 250 mD and porosity of ~22.5%, were saturated with brine and exposed to displacement at 75, 200, 300, and 400 °F (24, 93, 149, and 204 °C respectively). Tests on separate cores examined the effects of temperature and NaOH concentration. Permeability damage intensified with rising temperatures, attributed to the hydrothermal impacts. Reductions of 33%, 36%, and 39% occurred at 75 °F (24 °C). The study noted more pronounced permeability loss between 75 °F (24 °C) and 300 °F (149 °C), where temperature-dependent damage mechanisms were most active. Flow reversal in permeability tests only partially restored performance, with greater recovery observed at lower temperatures and NaOH concentrations. Reduced restoration at higher conditions suggests that mechanisms beyond fines migration—such as grain overgrowth, mineral precipitation, or scale formation—contributed to irreversible permeability damage [5]. This underscores the significant impact of scaling and mineral deposition on rock permeability, particularly under high-temperature, high-pH water (steam) injection, a critical consideration for managing well performance.

3.4. Mineral Transformation

While mineral reactions and evolution are secondary mechanisms influencing changes in petrophysical properties during thermal fluid injection, they play a crucial role in the transformation of host and clay minerals. These transformations, especially in water-sensitive or acid-sensitive minerals, significantly alter the reservoir's petrophysical characteristics. For instance, Okoye et al. [113] observed, through electron microscopy, that feldspar transforms into kaolinite under high-temperature and high-pH conditions. Subsequently, kaolinite dissolves and reprecipitates as zeolite and amorphous silica, blocking pore throats and further altering reservoir properties. Additionally, kaolinite may convert into montmorillonite—a water-sensitive mineral—when temperatures exceed 200 °C.

The injection of strongly alkaline fluids intensifies the severity of mineral evolution, as most minerals are more reactive in these environments [114]. Temperature and pH are key factors in altering clay minerals such as montmorillonite, illite, and kaolinite, especially with abundant Na^+ and K^+ ions, according to Zhuang et al. [115]. For instance, montmorillonite transitions from disordered to ordered at 150 °C, then forms analcime at 200 °C and pH 11, with visible analcime crystals at pH 13. Analcime, though less water-sensitive, can still interact with acidic fluids to form precipitates, worsening formation damage.

Kudrashou and Nasr-El-Din [116] provided a comprehensive review of the reactions of key sandstone minerals, which offers valuable insights into the mechanisms governing mineral evolution into different reservoirs. In their experimental investigations, the evolution

of a mineral mixture composed of quartz, kaolinite, and carbonate minerals, such as calcite or dolomite, was studied under conditions of 400 °F (149 °C) and 1000 psi. They noted that these minerals could change into montmorillonite, but this transformation only occurred in reactive systems where CO_2 was permitted to escape. Notably, dolomite showed a greater tendency to convert into montmorillonite than calcite.

Research indicates that under hydrothermal conditions, particularly above 175 °C, kaolinite and illite react with quartz and small amounts of calcite or dolomite to form montmorillonite. This transformation, which is accelerated in dolomite-rich environments, occurs rapidly under saturated steam conditions within the 200–300 °C range, common in thermal recovery processes. Foundational studies by Levinson and Vian [117] and Bayliss and Levinson [118] demonstrated that even trace dolomite, prevalent in Alberta deposits [119], can drive significant montmorillonite synthesis. As a swelling clay, montmorillonite severely impacts permeability and reservoir properties, making its formation a critical factor during steam injection.

Further experimental work supports these findings. Day et al. [120] confirmed that steam injection in reservoir cores containing kaolinite, illite, quartz, and dolomite promotes montmorillonite formation. Similarly, Boon [121] provided preliminary evidence from the McMurray Formation, suggesting enhanced montmorillonite generation during Steam Drive operations.

Static autoclave experiments by Boon et al. [17] simulating in situ conditions in Cold Lake oilsands revealed significant mineral transformations, including quartz, kaolinite, and dolomite dissolution, alongside the formation of analcime, chlorite, smectite, and calcite. These reactions, driven by variables such as temperature, pH, and salinity, were shown to damage permeability by dispersing fines, leading to high residual oil saturations in medium-to-fine-grained sands.

Flow experiments using sand packs under controlled variables—bitumen presence, buffered or unbuffered pH, temperatures of 200 or 250 °C, and salinity with or without 0.1 M NaCl—highlighted similar mineral changes. Dolomite, kaolinite, and quartz dissolved, while montmorillonite, calcite, analcime, and chlorite formed. These transformations, especially prevalent in SAGD processes, were heavily influenced by temperature and exposure time [17].

Hebner et al. [122] investigated reactions among kaolinite, quartz, and dolomite under in situ steam injection conditions (200–300 °C, up to 13.8 MPa). Key findings included the synthesis of analcime in experiments with intermediate and high pH, while smectite was prominent in neutral pH conditions but absent or minimal at higher pH. Variations in carbonate mineral formation were also noted: calcite appeared in only two experiments with 5% dolomite, whereas siderite formation was more consistent. These results underscore the influence of pH and dolomite on mineral transformations, particularly the formation of smectite, analcime, and carbonates.

Aquathermolysis, critical in thermal recovery, is strongly influenced by water composition. High-temperature water-mineral reactions, driven by steam quality and chemistry, destabilise kaolinite and promote zeolite formation over smectite when the residual liquid phase of injected steam with a pH of 12, contacts the reservoir at 200–250 °C [54]. These interactions highlight the significant role of water chemistry in dictating mineralogical changes during steam injection.

3.5. Wettability Alteration

Unlike other mechanisms that alter petrophysical properties through structural modifications, changes in rock surface properties induced by thermal fluids do not affect pore geometry but, instead, influence the effective permeability of individual fluid phases by

altering rock wettability [80]. This shift in wettability can significantly impact fluid flow dynamics within the reservoir.

Experimental studies reveal that low-salinity water enhances water-wetness on solid surfaces by expanding the electrical double layer at the rock-fluid interface [123]. However, this also intensifies fines migration, leading to pore plugging, increased pressure drops, and the formation of mineral and organic scales that diminish porosity and permeability.

Kar et al. [63] analysed wettability alteration during SAGD and ES-SAGD processes using Canadian bitumen (8.8° API) across five experiments. Contact angle measurements on sand samples from inside and outside the steam chamber revealed significant changes in wettability due to clay migration and asphaltene precipitation. These interactions altered reservoir rock properties, reducing recovery efficiency in both steam and steam-solvent co-injection scenarios.

A study by Kaito et al. [124] investigated asphaltene precipitation during the Solvent-Assisted SAGD (SA-SAGD) process by replicating conditions near the edge of the steam chamber, where bitumen and condensed solvent mix and drain due to gravity. Athabasca bitumen and a condensate blend were used, with the bitumen's density at 15 °C recorded as 1014.7 kg/m^3 and its absolute viscosity at 50 °C as 9137.3 cP. The experiment was conducted at two temperature settings, 120 °C and 150 °C, while maintaining a constant pressure of 3.5 MPa. The asphaltene precipitation curves from both tests followed a similar trend, showing that asphaltene began to precipitate when the solvent concentration exceeded approximately 50 wt%, and the final asphaltene precipitation amounts (APA) stabilised around 18 wt%. These results indicate a potential contribution to the in situ upgrading of bitumen when asphaltene precipitation occurs by the condensation of injected solvent and aggregates near the edge of the steam chamber.

4. Case Studies

In the SAGD process, slotted liner plugging is a well-documented issue, often resulting from the accumulation of fines migration and organic and inorganic particles. This blockage can restrict the openings in sand control devices and lead to pore space clogging near the wellbore [14,53]. Also, fines retention under high-temperature and pressure conditions may trigger the transformation of clay minerals, such as kaolinite, into smectite, a swelling clay that can significantly impair wellbore productivity [13,53].

4.1. Case I—Lower Grand Rapids (LGR) Formation

A case study by Williamson et al. [7] provides insights into two pilot SAGD well pairs in the LGR Formation, located in the Cold Lake/Lloydminster region. Petrographic analysis indicated that the LGR Formation contained less than 5% fines and non-swelling clays. The first SAGD well pair, equipped with a slotted liner, experienced a marked increase in differential pressure—exceeding 1000 kPa—after eight months of stable production, leading to a decline in production rates as per petrographic analysis. Although initial acid stimulation treatment yielded only minor and short-lived improvements, suggesting no plugging dissolution, a subsequent perforation treatment significantly lowered the differential pressure below 100 kPa and resulted in long-lasting enhancements onwards with low continuous solids production [7].

In their study of the first SAGD well pair, Williamson et al. [7] integrated operational data with petrographic analysis (XRD, SEM) of core samples collected before steam injection and after a perforation job. Their findings indicated that initial formation damage near the wellbore was caused by the mobilisation of fine particles, primarily kaolinite, when observing cores and liner, respectively. Subsequent mineral transformations under high-temperature and pressure conditions exacerbated the well's impairment. The rapid ramp-up of the electrical

submersible pump (ESP) likely generated a high influx, which mobilised these fine particles, leading to plugging near the wellbore. This blockage intensified the interstitial velocity of the flowing emulsion, causing further release of fine particles. Moreover, petrographic analysis of post-steam core samples revealed the presence of smectite, a swelling clay, suggesting mineral transformation [7].

4.2. Case II—Colony Formation (Mannville Sands)

Calcium carbonate scale commonly occurs in SAGD operations, particularly in the downhole environment. Pressure reduction causes CO_2 to outgas, shifting the bicarbonate-carbonate equilibrium toward carbonate formation, which precipitates calcium carbonate and lowers pH, exacerbating scaling. Over time, scale accumulation increases pressure drop and may fully block the liner, altering well performance, including temperature, pressure, and fluid production characteristics [52].

Erno et al. [52] identified pressure drop as the primary driver of calcium carbonate scaling, which can severely clog liners or screens, reducing fluid output. Indicators of scaling include increased pressure differential and subcool alongside accelerated production decline. Laboratory experiments were conducted to simulate downhole conditions and evaluate scale inhibitors [52]. Brine, replicating SAGD fluids, was flowed through a partially closed valve to induce flashing via pressure drop. At 200 °C and 2000 kPa, no flashing occurred with the valve fully open, but partial closure and increased upstream pressure at 220 °C facilitated conditions for scaling. These experiments, while not fully replicating field conditions, provided insight into scaling mechanisms and inhibitor performance. Under non-flashing conditions, brine flow was stable at 200 °C and 2 MPa. Inducing flashing via temperature increase and flow restriction caused rapid pressure buildup [52]. Switching from distilled water to brine further confirmed the significant role of brine in scaling-related pressure increases, as demonstrated by repeated pressure responses during testing [52].

4.3. Lessons Learned

The case studies reveal several key insights into the thermodynamic and chemical processes affecting SAGD production operations, particularly around the wellbore. It has been shown that the sand near the wellbore experiences the most intense thermodynamic changes, which play a significant role in the overall oil production performance. To better understand the physical and chemical interactions, particularly those that lead to fines migration and other formation damage mechanisms, laboratory experiments and the development of a detailed geochemical/thermal/wellbore-reservoir model are essential.

In hybrid SAGD processes, the choice of solvent type and injection strategy are critical factors that greatly influence performance. However, care must be taken with solvent selection, as certain solvents may destabilise asphaltenes, leading to precipitation in production or transportation lines. Beyond asphaltenes, oil fractions, reservoir clay types, and clay quantities all play a pivotal role in ES-SAGD performance.

Another key observation is the significant role of carbonate scale deposits in causing downhole screen plugging in SAGD wells, particularly in Canadian heavy oil reservoirs. Calcium carbonate deposition is believed to be triggered by pressure drops near the wellbore, and this phenomenon is further intensified at higher temperatures. Laboratory studies and field data, such as the large volumes of carbon dioxide vented at wells, confirm this link between pressure changes and scaling.

Lastly, the combination of physical laboratory models with numerical simulations has proven highly effective in shedding light on the effects of high-temperature processes within the reservoir. This integrated approach not only aids in understanding formation

damage mechanisms but also might help optimise energy consumption in SAGD operations, contributing to more efficient and sustainable production methods. It has been demonstrated that physical models with high reliability and repeatability can be both designed and effectively operated.

5. Knowledge Gaps and Future Research

Significant gaps in the understanding and management of formation damage mechanisms within SAGD operations remain despite extensive studies. Accurately identifying these mechanisms, assessing their interaction and detrimental effects on production, and developing effective mitigation strategies remain challenging. Standard industry practices often fall short of correctly diagnosing the underlying causes of formation damage, leading to ineffective remediation and prevention efforts. In some instances, these limitations result in the selection of suboptimal techniques, exacerbating the problem rather than alleviating it. Addressing these gaps requires a more nuanced and systematic approach to accurately characterise formation damage and develop targeted applications.

Current laboratory research on formation damage in SAGD systems reveals significant gaps in the comprehensive simulation of reservoir conditions. Notably, existing studies often fail to integrate the combined effects of pressure, temperature, salinity, and pH in a single experimental setup. This integration is crucial for accurately replicating the complex interactions between rock, fluids, and sand control mechanisms. This paper proposes research to address this critical gap by incorporating all these variables into a unified experimental framework.

Traditional sand retention tests have been frequently conducted under room temperature and low-pressure conditions, which do not adequately reflect the high-temperature and high-pressure environments typical of SAGD operations. Similarly, while oilsands have been subjected to elevated pressure and temperature in certain studies, these tests often lack the inclusion of near-wellbore devices or the investigation of how formation damage mechanisms interact under such conditions.

The identified gaps in current research, particularly regarding the interaction between fines migration and sand control screens, underscore the need for more comprehensive testing procedures that account for long-term performance. This is crucial for improving well productivity and mitigating formation damage in SAGD operations.

6. Proposed Testing Design for Formation Damage Assessment in Oilsands Under Field Conditions

Conducting experimental studies under representative field operating conditions is significant for determining the cause and type of formation damage generated by the effect of high pressure and high temperature.

Previous SRT experiments have only partially explored fines migration within porous media without any synergy between subsequent formation damage mechanisms. Screen evaluations are based on measurements of sand production and retained permeability in tests that facilitate quick flow stabilisation. Time-lapse experiments and visual slot inspections reveal that not only sand grains block the slots; instead, it is the accumulation and tight packing of fine particles around the sand grains near the slots that lead to reduced retained permeabilities, consequently changing the differential pressure and altering the fluid composition and behaviour.

Recently, an SRT setup [125] has been used to evaluate different screen configurations by measuring the produced and retained fine particles. However, these tests did not incorporate the interaction between fines migration and other formation damage mechanisms,

such as chemical damage (organic and inorganic scaling, clay swelling), thermal damage (mineral transformation, dissolution), and changes in wettability.

This paper introduces a high-pressure, high-temperature testing facility (HPHT-TF) to investigate behaviour and alterations in the rock-fluid system leading to flow impairment with qualitative and quantitative insights under HPHT conditions. The proposed research uses a cutting-edge testing infrastructure that can operate under field operating conditions, accommodating both porous media and sand control screens. This setup will represent a significant advancement in thermal well testing, designed to withstand the HPHT and stress levels encountered in SAGD processes.

The HPHT-TF comprises several components. These include a cylindrical HPHT cell with an internal diameter of 2.5 inches and a length of 12.5 inches with attached pressure ports, an injection system, a top platen with injection ports, a base plate that holds the sand screen coupon, an axial loading system, pressure transducers, a backpressure regulator, a component for measuring sand and fine particles, a turbidimeter, and a data acquisition system. It also includes seven inlet and outlet valves to control flow direction during sample saturation and testing. The following schematic diagram (Figure 3) shows the different setup's components.

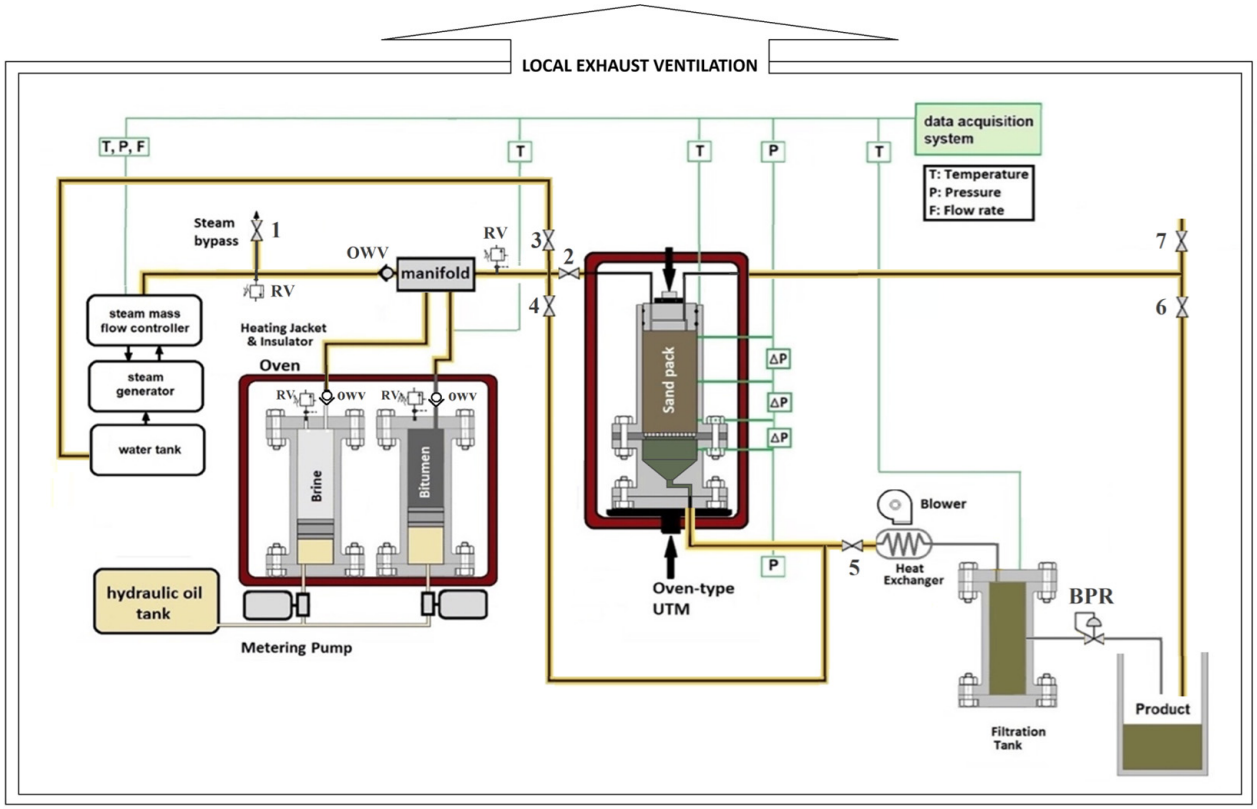


Figure 3. Designed High-Pressure High-Temperature Testing Facility (HPHT-TF).

The testing uses oilsands' samples containing kaolinite clay representative of the McMurray Formation and selecting a flat screen coupon representing the sand control device. The experimental process will involve saturating the sample with brine, measuring the permeability, and flowing the sand pack from the top of the sample to represent the conditions around the SAGD production well. High salinity brine followed by low salinity brine will allow the evaluation of the effect of salinity at reservoir temperature and pressure conditions on fines migration. In the same fashion, high and low pH conditions will be tested.

The testing includes analysing produced fluids collected in a tank and sand samples retrieved from the HPHT cell. This phase will incorporate laboratory data on pressure,

temperature, flow rate, pH, and salinity to accurately correlate with sand sample conditions within the HPHT cell over time.

The HPHT testing measurements and post-mortem analysis will identify potential sources of formation damage utilising scanning electron microscopy and energy dispersive X-ray, a critical step in demonstrating the presence of different formation damage mechanisms such as organic and inorganic scaling, mineral transformation, and wettability alteration, as well as their interactions are triggered in high-pressure and high-temperature environments. The research will aim to qualify these damage mechanisms by addressing three key aspects: determining the location of formation damage, assessing its severity, and evaluating its impact on production.

7. Summary and Conclusions

This review has examined the process of different formation damage mechanisms, focusing on its impact on the near-wellbore region in SAGD operations. Both field observations and coreflooding experiments consistently highlight the detrimental effects of formation damage on well productivity and screen plugging in SAGD wells. Theoretical and experimental studies have shown that factors such as particle and pore size distribution, salinity, pH, temperature, pressure, fines wettability, effective stress, and well completion all play critical roles in formation damage processes. It is relevant to mention that fines migration can be a trigger factor of some other damage mechanisms.

Previous laboratory studies are often limited in simultaneously accounting for the combined effects of pressure, temperature, salinity, and pH in a single test that integrates oilsands, water flow, and sand control mechanisms to analyse the formation damage processes and their interactions. This limitation highlights the central innovation of the research with the HPHT testing introduced in this paper. Sand retention tests are generally conducted at room temperature and under low-pressure conditions. Similarly, experiments involving oilsands are typically performed at elevated pressures and temperatures but do not simulate near-wellbore conditions or thoroughly examine the complex interactions and mechanisms contributing to formation damage.

The proposed experimental setup will be utilised to investigate the underlying mechanisms of interactions between oilsands, brine, and sand control screens, while also measuring their effects on permeability damage. This study aims to deepen our understanding of formation damage mechanisms and their interrelationships, enabling the development of effective prevention strategies. The findings from this research will be relevant in mitigating wellbore blockages, minimising water consumption in thermal gravity drainage operations, boosting wellbore productivity, and reducing both the carbon footprint and water waste associated with the process.

The insights gained from this review hold substantial implications for advancing the SAGD industry, particularly in optimising formation damage management strategies and improving overall operational performance. The ongoing challenges associated with different formation damage mechanisms in SAGD operations highlight the importance of continued research in this area. Advancements in both experimental methods and modelling techniques are essential for developing more effective strategies for managing formation damage. By addressing the current limitations in understanding and testing, the industry can achieve better well productivity and extend the lifespan of SAGD wells.

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