A Review of Fines Migration around Steam Assisted Gravity Drainage Wellbores

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Abstract

This paper reviews the state-of-the-art experimental and theoretical methods on fines migration around Steam Assisted Gravity Drainage (SAGD) wellbores. The in-situ migratory particles can deposit in the pore space and result in pore throat plugging within the porous medium. This process damages the permeability around the sand control screen. This review includes field observations, experimental works, and simulations solving fines migration mathematically.

Field observations indicate higher pressure differentials between the SAGD injector and producer due to the plugging of the sand control screen and surrounding formation. Coreflooding experiments confirm that the fines migration process is an essential contributing factor to the permeability damage near the SAGD wellbores. Macroscopic analytical models have also been extensively used at the lab-scale to predict the permeability variation by the fines migration. The modeling studies are focused mainly on consolidated sandstones, but the impact of sand control devices has not been incorporated.

Many papers have been published to describe the influential factors controlling the fines migration process. However, the interaction between the wellbore completion and surrounding sand from the fines migration perspective has not been adequately explored. Despite numerous limitations in representing the reality near the SAGD wellbores, sand control testing procedures provide a short-term evaluation of the sand retention and flow performances of the sand control device in unconsolidated sand. However, these tests do not account for the transient behavior and long-term permeability variation caused by the fines migration process. This paper presents an integrated general-purpose procedure for the design of sand control devices in SAGD wells, addressing the gaps from this review.

Keywords: Fines migration, Unconsolidated sands, Sand control device, Plugging

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1. Introduction

Steam assisted gravity drainage (SAGD) is the most common thermal recovery method for in-situ bitumen extraction in unconsolidated Alberta oil sands. The SAGD process involves the steam injection into a horizontal injector well drilled about five meters above the horizontal producer well close to the oil sands bed. The high-temperature steam heats the bitumen at the edges of a steam chamber developed around the injector well. The melted bitumen, along with condensate water, flows by gravity toward a liquid pool above the producer well and is pumped to the surface [1].

SAGD wells are equipped with sand control screens to prevent excessive sand production while creating the least resistance against the flow of reservoir fluids and fines. Fines migration is generally noticeable in unconsolidated sands [2]. Fine particles are known as very small loose particles in the reservoir that can pass through mesh screens of size 400 (37 μm) [3] or size 325 (44 μm) [4, 5]. These particles may contain clay minerals (kaolinite, illite, smectite, chlorite) and non-clay minerals (quartz, silica, feldspar, calcite, dolomite) [3, 6].

Fine particles are initially attached to the coarser grains by the net attractive surface forces and gravitational force and are prone to migration [7]. When the wetting phase starts to flow in the reservoir, fine particles may be entrained in the flow by net repulsive surface and hydrodynamic forces [7, 8, 9]. The mobilized particles migrate with the flow inside the porous medium and may plug the thin pore throats or accumulate behind previously bridged particles [10]. The retention of fine particles can significantly damage the permeability of the porous medium [11]. The release and retention of fine particles in the porous medium around the wellbore (in this text referred to as the "completion zone") is a complex process involving several interacting phenomena, such as organic and inorganic scaling.

Theoretically, the sand control screen can influence the fines migration, including the release and retention of the fines and fine particles production into the wellbore [12]. Indeed, they are inherently related to the screen aperture size and open flow area (OFA), causing flow convergence and spatially increasing flow velocities by a factor of 10-20 through the device [13]. The flow convergence increases the inertial retardation effect, which increases local fines concentration in the completion zone [12]. Fines retention, mobilization, and production would increase or decrease the completion zone's permeability over time [13, 14].

This paper integrates previous findings on fines migration in thermal wells from various experimental and theoretical studies. It discusses the field observations, physical mechanisms, significant contributing factors, and the design of sand control screens regarding fines migration. The literature gaps in fines migration around thermal wells are identified, and challenges in evaluating wellbore completion's impact on near-wellbore damage by fines migration are determined. In the end, a conceptual framework is developed to reconcile and extend past research on the fines migration issue, particularly on Alberta oil sands.

2. Fines Migration in Oil Sands

2.1. Fines origin, mineralogy, and size

A generic geological description of oil sands is depicted in Figure 1, where bitumen is separated from sand or clay particles by a thin layer of water. In low-grade oil sands with high residual water saturation, clusters of silts and clay particles exist within the framework of coarse sand grains [15, 16]. SEM images indicated that clay minerals coat individual sand grains in the Clearwater Formation in the Cold Lake area [17].

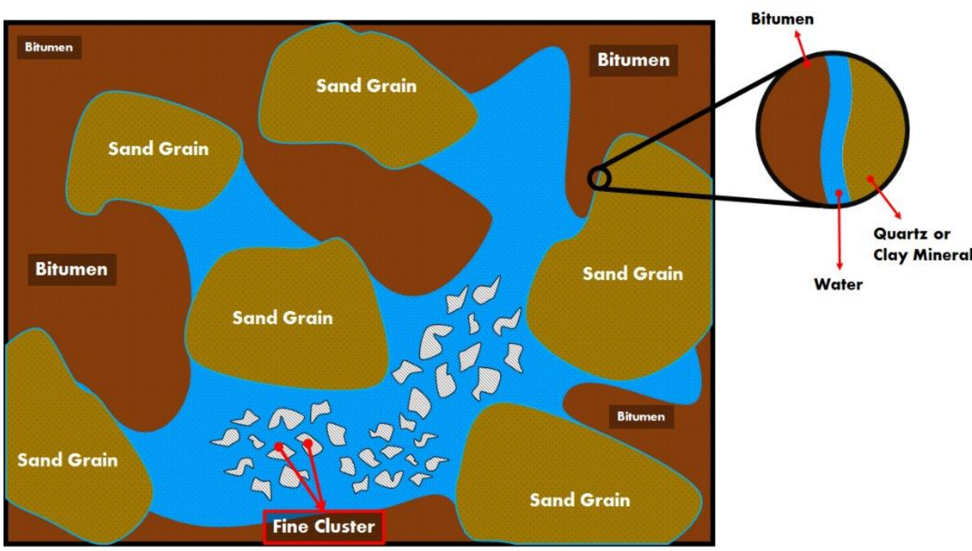


Figure 1. Geological description of Athabasca Oil Sands (Modified after [15])

Alberta oil sands contain a considerable amount of fine particles in the silt size (4-44 μm) and clay size (smaller than 4μm) [4, 18].

The fines may contain clay minerals (such as chlorite, kaolinite, illite, and smectite) and non-clay minerals (such as quartz, silica, feldspar, calcite, and dolomite) [3, 6]. The mineralogical composition of five oil sand deposits in Alberta is shown in Table 1.

Table 1. Mineralogical description of Alberta oil sands [18]

Oil Sand Deposit		ATHABASCA				PEACE RIVER		WABSCA				COLD LAKE		LL*	
Formation		McMurray		Clearwater		Bluesky/ Gething		Wabiskaw		Grand Rapids		Clearwater/ Grand Rapids		Dina	
Samples		247		15		32		15		6		15		13	
		M	Range	M	Range	M	Range	M	Range	M	Range	M	Range	M	Range
Total Mineral %	Quartz	80	41-97	63	21-87	69	17-92	81	57-96	66	55-87	75	30-98	83	56-95
	Potash Feldspar	2	0-16	6	0-42	2	0-7	4	T-20	10	0-30	7	0-19	3	0-23
	Plagioclase	0.1	0-8	3	0-11	N		1	0-6	12	0-41	7	0-27	2	0-8
	Calcite	0.2	0-28	4	0-12	0.5	0-5	0.9	0-9	0.3	0-2	0.1	0-2	0.1	0-1
	Dolomite	0.4	0-9	4	0-13	5	0-4	1	0-7	N		0.6	0-5	1	0-16
	Siderite	1	0-20	2	0-4	N		0.3	0-2	3	0-15	N		N	
	Pyrite/ Marcasite	0.4	0-10	5	0-45	6	0-62	1	0-4	1	0-8	0.1	0-2	N	
	Kaolinite	9	1-27	5	0-19	15	4-27	7	2-18	4	2-7	3	0-11	6	1-15
	Mica	1	0-8	T	0-2	0.3	0-4	0.8	0-2	0.2	0-1	0.5	0-3	2	0-8
	Illite	4	T-10	6	1-15	3	T-11	3	T-9	3	1-10	3	T-13	2	T-7
	Chlorite	N		0.3	T-4	N		0.1	0-1	N		1	T-7	N	
	Smectite	N		1	T-7	N		N		N		3	0-17	N	
Clay Minerals % (<2 µm)	Kaolinite	65	28-90	39	0-67	85	47-94	74	57-85	54	40-78	52	0-91	67	20-96
	Illite	31	7-54	44	29-66	13	6-35	24	14-38	36	16-60	25	7-42	26	4-60
	Chlorite	0.8	0-18	6	1-15	0.9	0-18	2	0-5	5	0-9	8	2-25	4	0-17
	Smectite	0.2	0-7	11	2-26	0.3	0-3	0.6	0-5	5	0-11	15	0-42	3	0-27
	Mixed-Layer Clays	3	0-26	N		0.7	0-4	N		N		N		N	
	Kaolinite/ Illite Ratio	2	0.2-11	0.9	0-2	7	1-15	3	2-6	2	0.7-5	2	0-9	3	0.6-13

M=Mean, T = Trace, N= Not Detected *: LLOYDMINSTER AREA

Particle size distribution (PSD) of the McMurray Formation in the Athabasca region has been represented by four PSD categories, with fines content from 5% to 14.5% [4]. Kaolinite and illite are the dominant clay minerals in oil sands [18, 19]. There is no information regarding the percentages of clay and silt minerals for in-situ core samples. Nevertheless, the characterization of an Athabasca oil sand reveals that most, but not all, of the clay minerals are in the clay size fraction [20]. It reveals that non-clay silt-size minerals would also contribute to the fines migration process.

2.2. *Field observations of the fines migration*

Plugging of slotted liners in SAGD wells has been reported as a common problem [21], which can be attributed to the fouling and scaling of organic and inorganic migratory particles [21, 22]. A high accumulation of fine particles can also cover the sand control slots' openings and plug pore spaces in the near-wellbore region. In some cases, under elevated temperatures and pressure conditions due to fines retention, clay minerals, such as kaolinite, may transform into smectite [22]. Smectite with a swelling behavior may significantly damage the near-wellbore region and reduce wellbore productivity [10].

Williamson et al. [23] published field observations of two pilot SAGD well pairs in the Lower Grand Rapids (LGR) Formation of the Cold Lake/Lloydminster area. The petrographic analysis showed that the LGR Formation contains less than 5% fines and non-swelling clays. The producers of the first and second SAGD well pairs were completed with slotted liner (SL) and wire wrapped screen (WWS), respectively. After eight months of steady oil production, the differential pressure between injector and producer of the first well pair started increasing to above 1000 kPa, and the production rate was reduced. The initial treatment program, as acid stimulation, showed marginal and short-term improvement compared with the next treatment (perforation job) with significant and long-lasting results. The perforation job treatment resulted in lower differential pressure below 100 kPa. In contrast, the second well pair had stable differential pressures over its lifetime and delivered higher production rates showing that WWS was a better sand control performance.

For the first SAGD well pair, Williamson et al. [23] combined operational data with petrographic properties (XRD, SEM) of core samples obtained before steam injection and after perforation job (post steam). They concluded that the near-wellbore was initially damaged by fine particles (mostly kaolinite), and later, mineral transformation under high temperature and pressure conditions caused additional well impairment. It was believed that a fast ramp-up by the electrical submersible pump (ESP) generated a high influx, which mobilized the fine particles toward the slotted liner and plugged the pore spaces near the wellbore. This plugging intensified the interstitial velocity of flowing emulsion and caused a further release of fine particles. Besides, the petrographic results showed the presence of smectite as a swelling clay in the post-steam core samples, indicating mineral transformation [23].

Romanova [22] analyzed the plugging materials of a slotted liner recovered from a well in the McMurray Formation (Long Lake area). The results showed that the primary plugging materials composed of clay-sized particles (mostly kaolinite) combined with the corrosion products.

2.3. Fines migration in coreflooding experiments

Few works have been published on laboratory study of fines migration in Alberta oil sands through coreflood experiments on core samples.

Permeability variations on core samples from Cold Lake oil sands were determined by establishing single-phase bitumen flow, resulting in an unexpected decrease in permeability [17]. Absolute permeability of 1100 mD at the beginning of the test dropped to 234 mD after flooding the core with heavy oil at high temperatures (up to 149ºC). The absolute permeability in single-phase heavy oil flow, 580 mD at 66ºC, also dropped to 175 mD when the core was heated to 149ºC for one day. XRD and SEM images of samples were taken from the core's inlet and outlet and compared with the initial oil sands to investigate the causes of permeability drop. It was observed that clays coating the sand grains detached from the inlet and plugged the pore throats near the outlet. The detachment mechanism was likely attributed to weakening the bonding forces between the sand grains and clay coatings at a higher temperature of 149ºC [17].

Kwan et al. [24] performed a series of tests on both preserved and repacked core samples of Cold Lake oil sands and confirmed the permeability impairment by fines migration. The tests were conducted at different salinity, flow velocity, and flow reversal conditions. The results showed that preserved core samples had much higher initial permeability than repacked samples due to particle redistribution. In all experiments, the permeability was reduced when both 2% NaCl brine and distilled water were injected, or the flow rate was increased. However, the reduced permeabilities were much lower for preserved samples having high initial permeability. The permeability reduction was attributed to fines migration and plugging of pore throats in the flow direction. It was also found that reversing the flow direction and injection of Methylene Chloride could partially recover the impaired permeability. Figure 2 shows the permeability variations during different test stages for a preserved core sample.

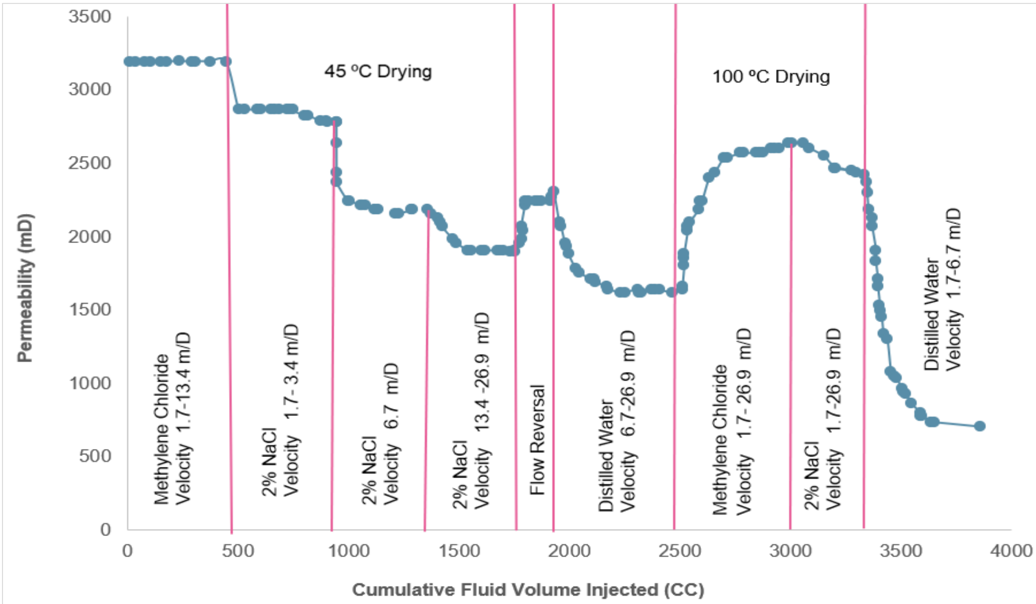


Figure 2. Permeability variations of a preserved oil sand sample in different flow conditions [24].

3. Influential Factors in Fines Migration Process

Table 2 summarizes the influential factors in five categories: (1) porous medium-related factors, (2) carrier fluid-related factors, (3) environmental factors (temperature), (4) well operating-related factors, and (5) well completion factors. Some factors are generic, and others are specific to thermal operation in unconsolidated oil sands. The effect of these factors has been investigated through many coreflood experimental tests, especially on homogenous Berea sandstone cores [3, 25, 26, 27, 28, 29, 30, 31]. A few flow tests have also been conducted on unconsolidated sand packs using synthetic or natural sands [3, 25, 27, 32, 33, 34]. The tests included various scenarios such as piecewise flow rate increase, gradual salinity decrease, single-phase, and multi-phase flow with polar oil, non-polar oil, and solvents. The fines migration was measured by monitoring effluent fines production and permeability variations in the core plugs and sand packs [10, 25].

Table 2. Factors influencing fines migration process in porous media [6, 9, 10, 35, 30, 36]

Category	Influencing Factors
Porous medium-related factors	Pore and particle size distributions, compaction, oil sand evolution around the wellbore, formation fines content and mineralogy, grains' and fines' wettabilities
Carrier fluid-related factors	Brine salinity, brine pH, composition (salt type, the valency of ions), multi-phase flow conditions (water cut, steam-breakthrough, emulsion)
Environmental factors	Temperature
Well operating factors	Wellbore flow rate (flow velocity), production ramp-up
Well completion factors	Sand control device characteristics (type, aperture size, open to flow area)

3.1. Porous medium-related factors

3.1.1. Pore and particle size distribution

The size distributions of particles and pores play an essential role in the migration of fine particles and retention processes. Large-sized particles would be released by lower drag forces and captured in narrow pore throat by a mechanism known as size exclusion or straining. This mechanism takes place below a critical pore throat to particle diameter ratio. Several small particles can form a bridge at the pore throats entrance when simultaneously approach a pore throat due to hydrodynamic effects [37].

Conventionally, one-third, one-seventh, and one-fourteenth rules of thumb were proposed for transportation and retention of fine particles in porous media [35, 38]. These rules state that:

- Fine particles larger than 1/3 of the mean pore size can bridge at pore throats,
- Fine particles smaller than 1/3 but larger than 1/7 of mean pore size deposit at pore surfaces, form bridge at pore throats and reduce effective pore/pore throat size,
- Fine particles smaller than 1/7 but larger than 1/14 of mean pore size deposit at pore surfaces and reduce effective pore size, when the effect of gravitational force is significant compared with the drag force
- Fine particles smaller than 1/14 of the mean pore size pass through the pores and cause no damage.

However, many experimental results contradict the above rules due to the porous media's complex nature [38].

The average pore diameter, pore throat size, and the pore body to the pore throat size ratio depend on several factors, including the depositional history, grain size, grain geometry, fines content, and compaction level of the formation. Several methods have been suggested to calculate the mean pore/pore throat size based on particle (grain) size distribution (PSD), permeability, and porosity [39, 40, 41, 42, 43, 44].

Abram and Cain [4] classified the McMurray Formation oil sands into four representative PSD classes (Figure 3). DC-I is the finest PSD with the highest fines content of 14.5% (3% clay). Classes DC-II, DC-III, and DC-IV have fines content of 7.4%, 5.4%, and 4.2%, respectively [4]. According to the one-third rule of thumb mentioned above, plugging particle sizes of 3.6-16.8 microns and 4.1-19 microns have been stated for Class II and Class III, respectively [35].

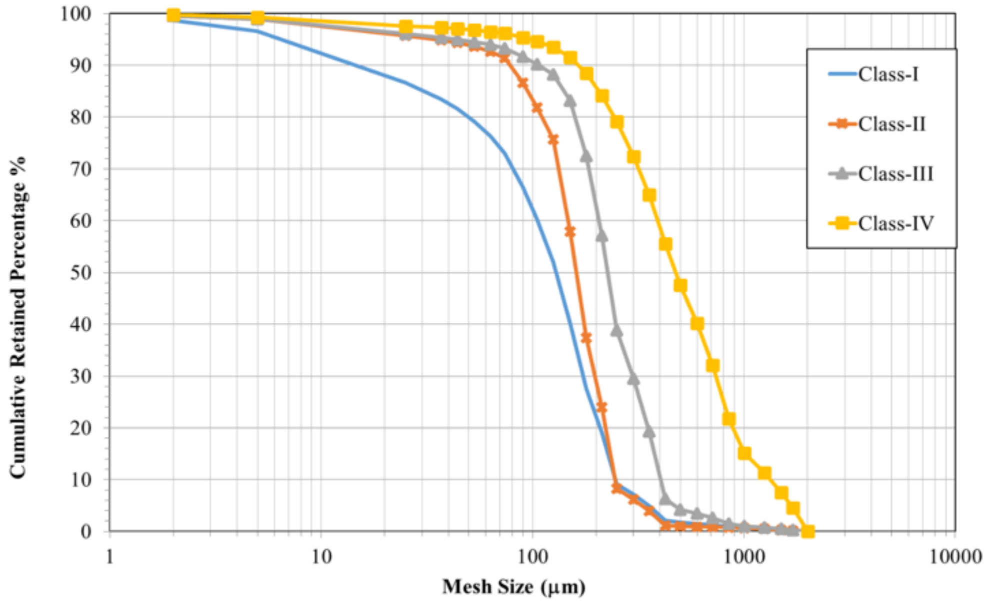


Figure 3. PSD of the representative classes of oil sand in McMurray Formation [4].

3.1.2. Compaction

The compaction of the reservoir sands changes as the effective stresses evolve; hence, the pore structure is altered. It has been observed that the critical velocity to mobilize fine particles in a core sample from Grand Rapids Formation in the Cold Lake area decreased as the effective stress increased [45]. A few recent works also investigated stress effect on fines migration and permeability impairment in an unconsolidated sample with a PSD similar to McMurray Formation [46, 47]. The results indicate that higher effective stress leads to less sand production but higher plugging and permeability reduction due to fines migration.

3.1.3. Oil sand evolution around the wellbore

In SAGD wells, there is typically a gap between the formation and sand control screen after the screen installation. Because of the unconsolidated nature of the oil sands and bitumen melting during the pre-heating phase, the sand collapses around the liner, hence developing a high-porosity high-permeability zone with low effective stress [35, 48]. During the steam injection phase and the steam chamber expansion, the effective stress builds up and causes gradual compaction of the collapsed zone [35, 36, 49]. Factors such as in-situ stresses, thermal expansion, and shear dilations influence effective stress around the liner [49]. The gradual effective stress build-up around the screen results in smaller pore sizes and higher interstitial velocities, which favor fines detachment and plugging tendency in narrow pore throats.

3.1.4. Fines characteristics

3.1.4.1 Fines mineralogy

The mobilization and retention of fine particles are also affected by the mineral composition and fraction of mobile fine particles within porous media. Fine particles may include non-clay and clay mineral particles (charged or uncharged) and show different colloidal behavior in contact with saline water. Smectite swells six to ten times its original volume and restricts fluid flow in the pore space [50]. Kaolinite and illite, which are the primary migratory clay minerals in oil sands, may disperse in low salinity brine, fill pore bodies, or bridge the pore throats [50]. The dispersion of clay materials is controlled by their cation exchange capacity (CEC); higher brine salinity is required to disperse the clay minerals with a higher CEC value. The CEC values of smectite, illite, and kaolinite clays are in the range 80-150, 10-40, and 2-5 meq/100 g, respectively [16].

3.1.4.2 Fines content

Higher fines content increases pore and screen plugging tendency in SAGD production wells. Sand control design in formations with more than 15% fines content has proved problematic due to fines migration [50]. Sand retention testing (SRT) results with a single-slot slotted liner coupon also showed severe plugging tendency in the sand pack with high clay content (kaolinite and illite) [21].

Russell et al. [11] conducted systematic experimental research on unconsolidated sand samples to investigate the effect of kaolinite content on permeability damage during a step-wise decreasing salinity level. Results showed higher permeability reductions for the higher kaolinite content, justified by a high concentration of dispersed kaolinite particles in the carrier fluid, which increased the pore throats plugging.

3.1.5. Wettability

The wettability of the formation fines affects their transport in the porous media. Mucke [3] found that fine particles tend to move with the wetting fluid phase. Clay particles are usually water wet and tend to flow when water is being injected or produced [3]. Mixed-wet fine particles move along the interface of two-phase flowing fluid through the porous media [3].

Investigations of various wettability combinations (water-wet rock/water-wet fines; water-wet rock/oil-wet fines; oil-wet rock/water-wet fines; oil-wet rock/oil-wet fines) through the flooding of sandstone cores with fines suspension showed more reduction of porosity and permeability when the rock and fines had the same wettability [51]. In this case, fines plugged the thin pore throats and filled the adjacent pore spaces. However, minimal damage has been observed when fine particles and rock core plug had different wettability [51].

The widely accepted structural model developed for Alberta oil sands indicates the water-wet behavior of sand grains, including a water film around them as an interface between grains and bitumen [15]. Fine particles usually cover the sand grains, and in some cases, clusters of fine particles saturated with water may exist [15].

3.2. Carrier fluid-related factors

3.2.1. Salinity and pH

Some brine characteristics as carrier fluid of fine particles in the reservoir, including salinity, pH, and composition, significantly impact the fines migration process. At low salinity, high pH, and the presence of monovalent cations, the net electrical interaction between fine particles and grains becomes repulsive (high zeta potential), and fines are detached from the pore surfaces [52, 53].

Experimental works performed by Khilar and Fogler [28] introduced the critical salt concentration (CSC) as a certain salinity level below which fine particles are released and stay suspended. For a NaCl brine system in consolidated cores of Berea Formation, CSC values of 0.07 M, 0.03 M, and 0.004 M corresponding to pH values of 8, 8.5, and 9.5 were detected [54]. It was found that a CSC exists only for monovalent cations. Brines with bivalent and trivalent cations have no remarkable effect on fines migration. Different monovalent cations have different impacts on the dispersion or release of fine particles in low salinity brine. An order of Li^{+}=Na^{+} > K^{+} > NH^{+}_{4} > CS^{+} was observed [54].

The H^{+} ion, as a monovalent cation, has a reverse effect on the dispersion behavior of the charged particles. At high pH values, the zeta potential becomes highly negative, which results in a significant repulsive force causing the release of fine particles [30]. Exposing a brine-saturated core (0.51M NaCl) to the freshwater at pH 2.0 did not result in a decline in permeability. Little change in permeability was observed for pH up to 9.0 [30]. However, a rapid and considerable decrease in permeability was observed at pH>11.0.

Several publications confirmed that the rate of salinity changes has more effect on the release of fine particles than the absolute salinity [26, 30, 54]. A continuous versus abrupt salinity decrease led to less permeability damage. It was attributed to a log-jam effect where a high concentration of released particles in a sudden salinity decrease could significantly plug the pore throats [30].

In the SAGD oil recovery process, the condensate water at the steam chamber's edge is expected to combine with high-saline formation water. Therefore, relatively low salinity water is produced from the liquid pool associated with bitumen emulsion. Salinities in the range of 400 ppm to 3400 ppm of NaCl brine and pH values from 7.1 to 8.8 have been reported for produced water at different SAGD projects [53]. A gradual increase in pH level is expected when steam is injected with an alkaline liquid residual of the boiler-feed [2]. These low salinities associated with high pH values in SAGD operations would promote the repulsive surface forces and release fine particles near-wellbore regions. The results of the investigations into the effect of salinity and pH on permeability damage of pre-pack samples representing McMurray Formation showed a good agreement with the theory of clay dispersion in interaction with saline water [53, 55].

3.2.2. Multi-phase flow conditions (water cut, steam breakthrough, emulsification)

Muecke [3] combined micromodel and linear flow studies to understand the fines migration process. He performed a series of single-phase and multi-phase linear flow tests in a large-scale sand pack (122cm length, 3.81cm diameter) to verify visual observations from their micromodel. The two-phase flow of oil and water with migrating fines toward the SAGD producer is simulated in the micromodel, as depicted in Figure 4. Results showed that mobilized fine particles could establish mechanical bridges at pore restrictions.

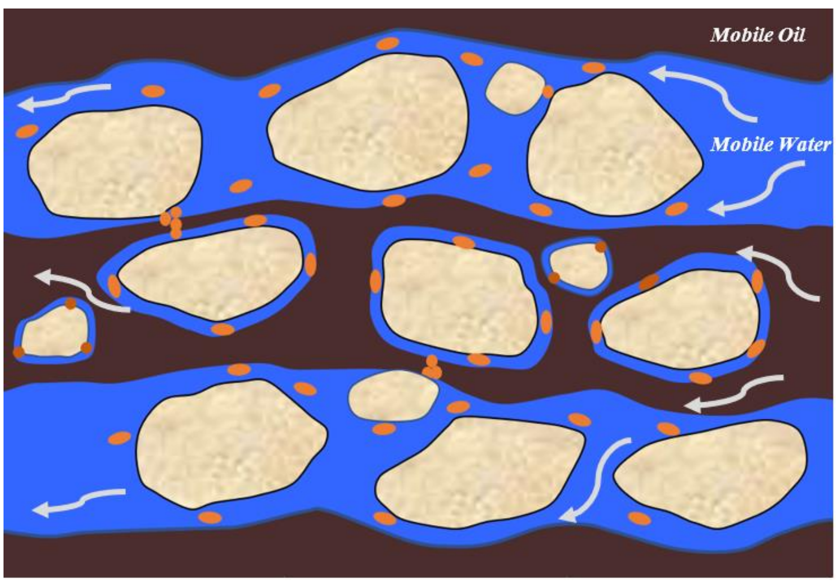


Figure 4. Fines migration with the simultaneous oil and water flow (Modified after [3]).

Muecke [3] also found that fine particles moved only with the wetting phase, and in multi-phase conditions, higher water cut would result in higher fines migration. Thus, in the SAGD process, with the simultaneous two-phase flow of condensate water and melted bitumen, water-wet fine particles move with mobile water. Two-phase flow tests in unconsolidated pre-pack samples with clay particles showed higher plugging and fines production than single-phase flow tests with non-wetting phase (oil). The testing results also showed that fines mobilization and migration are more substantial in higher water cut levels [56, 21, 49, 57, 58]. Three-phase flow (oil, water, and gas) resulted in the highest plugging and fines production [56, 57]. The three-phase flow test with gas injection resembles the live steam breakthrough in some SAGD producer segments. Although an operating steam-trap or subcool control is used to prevent the steam breakthrough, some intervals still may experience steam production due to reservoir heterogeneity and wellbore trajectory excursions.

The produced melted bitumen in the SAGD recovery has been reported as water-in-oil (W/O) emulation [59]. Studies showed that the W/O emulsion in the SAGD process has a higher viscosity than the oil [59]. Although there is no experimental work investigating the effect of emulsion flow on the fines migration process in unconsolidated oil sands, it appears higher emulsion flow viscosity may have a noticeable effect in displacing the fine particles due to the higher viscosity and drag.

3.3. Environmental factors (Temperature)

Experimental studies showed that increasing the temperature reduces the permeability due to the fine particles mobilization [28, 60] and fines release [61], which affect the concentration of attached particles [52, 62, 63]. It was observed that permeability was reduced to 69% when the temperature changed from 21.1°C to 162.8°C [60]. The rate of permeability damage of Berea sandstone cores reduced when the temperature was lowered [28]. Regarding the colloidal behavior theory, the repulsive electrical forces are more potent at higher temperatures, which boost the release of fines from pore surfaces and consequent permeability reduction [61].

More interesting results related to the effect of temperature and salinity on the permeability of sandstone cores were reported by Rosenbrand et al. [46]. It was found that the impact of salinity on permeability damage is different at 20°C and 80°C. Decreasing the salinity at 80°C had an insignificant influence on the already reduced permeability by temperature. In contrast to the salinity effect, the permeability reduction due to heating could be significantly restored by cooling the sample. This behavior was explained by the strong repulsive grain-particle and particle-particle interactions at 80°C. Here, the released particles do not form large aggregates and plug the pore throats or bridge at pore throats. The dispersed particles possibly form a suspension of interacting particles as a porous network in the pore bodies [46]. Thus, the permeability is reduced as the effective specific surface area for flow is increased by the porous network. This mechanism could be confirmed by the reversible effect of flow velocity on permeability variation in high-temperature experiments and no fines production during the flow test. Here, higher flow velocities could shear the suspended fine particles and increase the permeability. By cooling the sample, fine particles reattach to the pore surfaces and significantly restore the permeability [46].

Schembre and Kovscek [61] showed that permeability reduction in a Berea sandstone core with no fines mobilization at temperature levels up to 120°C while flowing brine with pH of between 7 and 10, and salinities of 0.01M to 0.05M. However, in the temperature range of 120°C to 180°C, more reductions in permeability and fines production were observed, indicating the transportation and straining of the released fines at pore throats [61].

Typical downhole temperatures for a SAGD producer well are in the range of 200°C to 230°C. The release and migration of fine particles are more likely at high-temperature SAGD conditions.

3.4. Well operating factors

3.4.1. Wellbore flow rate (flow velocity)

Laboratory investigations show that fines could be mobilized and migrated due to excessive drag forces from the high flow rates, even in the high-salinity brine injection [25, 26]. Gruesbeck and Collins [25] confirmed the existence of a critical flow velocity above which the entrainment of fine particles occurs and changes the porous medium's permeability. A critical velocity of about 25 cm/hr was reported for consolidated cores of Berea sandstone when the core sample was flooded with 2% KCl brine [25, 27]. However, later experimental tests showed much higher critical velocities in the range of 2000-5000 cm/hr for Berea sandstone cores even when the core was flooded with low salinity (0.035%) NaCl brine [26]. This difference can be justified with much lower initial permeability (about 50 mD) of core samples in the former experiments [25]. The lower initial permeability of the core sample in a test with a constant injection rate can generate higher shear stress or drag forces, which accelerate the release of fine particles.

The permeability decrease with low salinity was more significant than high salinity when the flow rate increased [26]. This phenomenon is justified by the high concentration of released particles in low salinity conditions, which increases the possibility of permeability damage. It was concluded that the concentration of released particles by the hydrodynamic effect is less than that by the colloidal effect [26]. The pore throat plugging is the major mechanism responsible for permeability damage where the concentration of released fine particles is low. In this case, the permeability rapidly drops and then becomes stable. However, other capture mechanisms such as surface attachment, sedimentation, and direct interception may simultaneously occur with high mobile fines concentration. These mechanisms lead to a significant decrease in permeability at earlier stages and a continuous reduction at later times [26].

For typical SAGD production rates of a horizontal wellbore, up to 4500 bbl/day [64], the near-wellbore flow velocities are not expected to be high enough to destabilize the fine particles. However, due to the wellbore's nonuniformity, some sections may experience high local velocities (i.e., high drag force) that trigger the release of fine particles near the wellbore. A sand control screen with a limited open flow area would amplify the release process by flow convergence and impact the near-wellbore retention concentration of fine particles.

3.4.2. Production ramp-up

SAGD wells may experience aggressive production ramp-ups following wellbore interventions. High-pressure gradients would be generated in this situation, causing the fines migration process over a finite time [35]. The rate of velocity increase (or ramp-up rate) also influences fine particles' release from pore surfaces. Local variations in pressure or flow velocity cause a spontaneous release process, while sudden bulk variations initiate a provoked release process everywhere in the whole medium [7]. From the experimental works, Gruesbeck and Collins [25] found that an abrupt change in bulk flow velocity can develop turbulent eddies due to the pressure disturbances, which enhance drag force on fine particles and their mobilization. This effect is evident in the tests by a sharp increase in effluent fines production [25]. Nevertheless, in low flow velocities less than critical velocity, the low concentration of released particles due to an abrupt change in velocity does not significantly change the permeability [27].

3.5. Well completion factors

Standalone screens such as slotted liners (SL), wire-wrapped screens (WWS), and punches screen (PS) have been widely employed in horizontal SAGD wells [56, 58]. Slotted liners (SL) are popular due to their low manufacturing costs and adequate mechanical integrity when running into long horizontal SAGD wells [21, 64, 65, 66]. The other options are preferable for the formations with severe plugging issues [65, 67, 68]. The SL specifications include slot width, slot length, slot density (number of slots per foot of pipe), and slot patterns (Figure 5), which result in an open flow area (OFA) in the range of 1-6% [64, 68]. Slot width and slot density are two critical factors that influence sand control and flow performance.

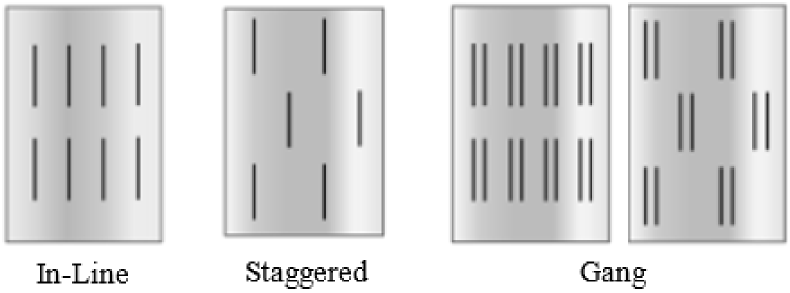


Figure 5. Slotted liner with different slot patterns [69].

In many SAGD applications, the screen has successfully minimized sand production, but they have often failed in managing the mobilized fines near the wellbore [19, 23, 50]. Permeability damage due to the fines migration process creates high differential pressures between the injector and producer wells. Such pressure drops have been observed after several, only a few months of production [23].

Pre-packed sand retention tests (SRT) using a scaled or full-scale screen coupon are usually conducted to evaluate the screen performance and establish the design criteria under representative SAGD wells conditions [64, 68]. Table 3 summarizes the testing variables of some recently published papers evaluating the screen's performance by the SRT equipment.

The screen sanding and plugging performance can be quantified by sand retention tests by measuring the total amount of the produced sand and the retained permeability. The latter is defined as the permeability of the combined screen and sand pack near the device relative to the initial permeability [64, 70]. Therefore, the retained permeability accounts for the extent of permeability reduction by fouling/fines materials covering the screen slots (screen plugging) and fines accumulation in the sand next to the screen (pore plugging) [13, 70]. The latter is caused by the organic and inorganic scaling as well as the fines migration process.

Table 3. Specifications of recent SRTs evaluating retained and produced fine particles for SAGD applications

Reference	SCD Type	Aperture Size (inch)	Slot density	Axial stress (psi)	Fluid Flow			
					Fluid type	Salinity (ppm)	pH	Flow rate (bbl/d)*
Mahmoudi et al. [35]	SL	0.01,0.014, 0.018,0.022, 0.026	30,42,54	2	Brine	0, 7000, 14000	6.9, 7.9, 8.8	1500-12000
Wang et al. [71]	SL	014, 0.018,0.022, 0.026	30,42,54	60	Brine	7000	7.9	1800-11000
Fattahpour et al. [36]	SL	0.014	54	0, 300,500,700	Brine	7000	7.9	2000
Montero et al. [57]	WWS	0.06,0.010, 0.014,0.018, 0.022	NA	60	Brine, Mineral oil, Nitrogen	400	7.9	4000-20000
Guo et al. [58]	SL	0.014, 0.026	30,54	0, 300	Brine	7000	7.9	2000
Wang et al. [56]	SL, WWS, PS	0.014, 0.18	54	60	Brine, Mineral oil, Nitrogen	400	7.9	4000-20000
Haftani et al. [53]	SL	0.014	42	2	Brine	7000,2600, 400,100,50, 0	7.5	4000-26000
Wang et al. [72]	SL	0.014	42	25, 400, 500, 700 (Lateral 25, 300)	Brine, Mineral oil, Nitrogen	7000	7.9	2500

Remarks:
PSD: McMurray Formation (Porosity: 0.29-0.35 ; Permeability: 1-3 Darcy)
Fines content: 5 w%, 7 w%, 14.5 w%
Sample diameter: 6 in
Sample length: 13.5 in, 16.5 in
Outlet pressure: 2 psi
Temperature: Room temperature (20°C)
*: Lower bond values are equivalent to typical flow rates for a SAGD well with 800 m horizontal length completed with a 7 in diameter SCD
SL: Slotted liner, WWS: Wire-Wrapped Screen, PS: Punch Screen

The sand retention tests provide data regarding the concentration of produced fines during the test and fines concentration at different sample intervals after the test completion. While the testing design does not fully capture the reservoir conditions (e.g., pressure and temperature), the results allow the relative comparison of different coupons. Coupons with smaller slot sizes (or aperture size) and lower slot densities result in higher fines retention near the coupon, thus lower retained permeability [73, 58]. A comparison of different tests indicates the effect of aperture size is more significant than slot density [58]. WWS coupons with the same aperture size as SL and PS exhibit the highest retained permeability due to the higher OFA [56, 57]. Some tests have been carried out to assess the impacts of multi-phase flow, pH, salinity, and stress on fines migration. High water cuts and three-phase flow with nitrogen are seen to cause higher levels of fines migration and permeability impairment [56, 72, 57]. Some observations indicate an increase in permeability due to the disruption of plugging bridges by turbulence effects of multi-phase flow [3, 21]. In addition to the testing procedure, the current SRTs have several limitations concerning radial flow geometry toward the screen, high-pressure and high-temperature conditions, and the use of natural unconsolidated sands and reservoir fluids.

4. Mathematical Modeling of Fines Migration Process

Mathematical modeling of the fines migration process within porous media allows predicting the near-wellbore permeability changes and wellbore productivity. The modeling also facilitates sensitivity analysis to assess the significance of contributing factors. Laboratory modeling is still necessary to calibrate and validate the mathematical model.

Traditionally, colloidal particles are species with a size between 0.001 and 1 microns and suspended particles with sizes larger than 1 micron [74, 75, 76]. The flow of natural fines in porous media can be thought of as a suspension transport problem in which physiochemical (surface forces) and mechanical forces intervene [7]. Therefore, in contrast to colloidal transport, the effect of intermolecular forces or diffusion is not significant [7].

Both macroscopic and microscopic models have been applied to describe formation damage due to mobilization, transportation, and retention of the fine particles. Microscale models include population balance models, random walk equations, and direct pore-scale simulation, which account for pore size distribution and pore level heterogeneities of porous media [8, 77, 78, 79]. The macroscopic models are based on continuum mechanics principles, where the material's behavior is averaged over a continuous mass rather than calculated for discrete particles. The macroscopic models predict the macroscopic distribution of the migrating particles (affecting the average porosity) and the extent of permeability variation. The microscopic physics and macroscopic equations describing the fines migration process within porous media are reviewed in the following sections.

4.1. Microscopic view

4.1.1. Physics of Fines Release

Figure 6 shows the schematic of forces acting on fine particles, including hydrodynamic forces (drag and lift), surface forces (electrical forces), and gravitational force. Electrical force includes attractive Van der Waals (F_{VDW}), repulsive Electrical-Double-Layer (F_{EDL}) and Born repulsive (F_{BRN}) forces. Fine particles can detach from rock surfaces when net repulsive forces or torques acting on particles overcome the particles' primary mechanical equilibrium [9, 10, 11, 26, 52, 80].

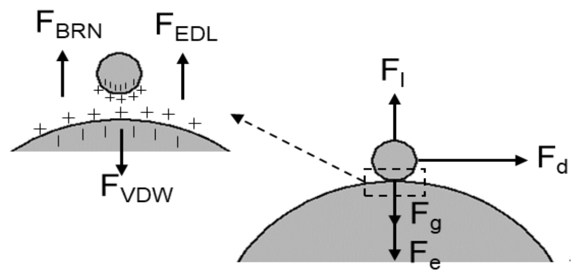


Figure 6. Schematics of forces acting on fine particles attached to the grain surfaces.

The drag force (F_d) is expressed as a function of fluid velocity (u), fluid viscosity (μ), mean fine particles radius (r_f), mean pore radius (r_p) and a dimensionless drag coefficient (ω) [11]:

$$F_d = \frac{\omega\pi\mu\, {r_f}^2\, u}{r_p} \tag{1}$$

The significance of lifting (F_l) and gravitational (F_g) forces are negligible compared with electrostatic and drag forces with fluid flow in porous media [11, 52, 81, 82]. Theoretical and experimental studies show that hydrodynamic forces are significant when the flow velocity is high enough (in order of 10^{-3} m/s), a condition that is often met near the wellbore [2].

The electrostatic force (F_e) is calculated based on electrostatic interaction energy between fine particles and grains, as described by the DLVO (Derjaguin-Landau-Verwey-Overbeek) theory. The total interaction energy (V) is the summation of London-Van der Waals (V_{LVW}), Electrical-Double-Layer (V_{EDL}) and Born repulsive (V_{BR}) energy potentials [9, 11, 74]:

$$V = V_{LVW} + V_{EDL} + V_{BR} \tag{2}$$

$$V_{LVW} = -\frac{A_{123} r_f}{6h}\left[1 - \frac{5.23h}{\lambda_w}\, ln\left(1 + \frac{\lambda_w}{5.23h}\right)\right] \tag{3}$$

$$V_{EDL} = \frac{128\,\pi\, r_f\, n_\infty k_B T \psi_f \psi_g}{k^2}\, e^{-kh} \tag{4}$$

$$V_{BR} = \frac{A_{123}\, {\sigma_c}^6}{7560}\left[\frac{8r_f + h}{(2r_f + h)^7} + \frac{6r_f - h}{h^7}\right] \tag{5}$$

where h is the fine particles-grains separation distance, A_{123} is the Hamaker constant, λ_w is the characteristic wavelength of interaction, n_∞ is the bulk number density of ions, k_B is Boltzmann constant, T is the temperature in Kelvin, k is the Debye-Huckel parameter, σ_c is the atomic collision diameter, ψ_f and ψ_g are the surface potentials of fine particles and grains, respectively.

The electrolyte solution as the permeating fluid in porous media develops an electrical double layer around charged (usually negative) solid surfaces of grains and fine particles (Figure 7). The outer layer, known as the diffusive layer, is rich in ions with opposite charges and move with the solid. The diffusive layer's thickness depends on electrolyte solution properties, including salinity, the valence of cations in solution, pH, and temperature. The electrical potential at the boundary between the diffuse layer and solution is known as the Zeta potential [7]. The V_{EDL} is the net repulsive interaction between double layers of fine particles and grains.

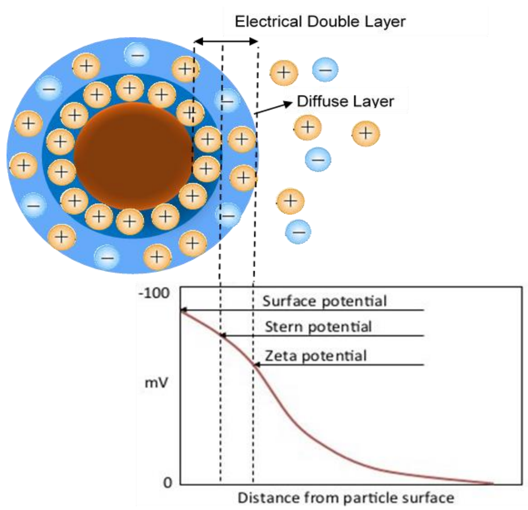


Figure 7. Electrical double-layer demonstration.

The surface potentials ψ_f and ψ_g are estimated based on the Zeta potentials as follows [11, 74]:

$$\psi_{f,g} = \tanh\left(\frac{ze\zeta_{f,g}}{4k_B T}\right) \tag{6}$$

where, $\zeta_{f,g}$ is the zeta potential of fine particles and grains individually, z is the valance of cations in solution, and e is the elementary charge (1.602×10^{-19} C).

By defining the total electrical potential, the electrostatic force (F_e) is quantified as the negative gradient of electrical potential concerning the separation distance between solid surfaces [11].

$$F_e = -\frac{\partial V}{\partial h} \tag{7}$$

Generally, where the zeta potential values positivity is greater than +30 mV and negativity is lower than −30 mV (Figure 8), the net electrostatic force is repulsive. Thus, fine particles tend to detach from the pore walls (grain surfaces) or separate from the surrounding particles [83]. In this circumstance, the dispersion resists aggregation and flocculation of particles. Therefore, depending on particle-particle and particle-grain interaction energies, different mechanisms of dispersion and flocculation are possible.

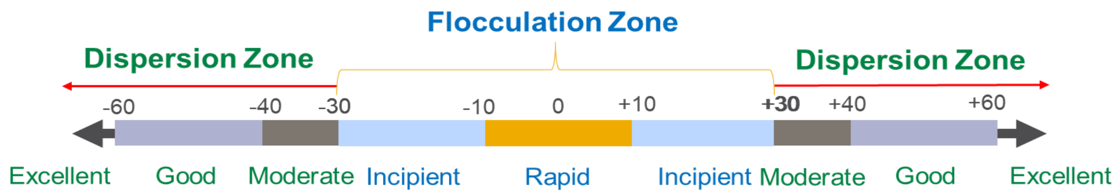


Figure 8. Variation of the zeta potential and charged particle behavior.

In most modeling cases, it is assumed that the release mechanism does not significantly affect permeability increase, and they only account for permeability decrease due to retention mechanisms [9, 11, 52, 63]. At high temperatures and low shear rates, the release of stacked platelet-shaped particles such as kaolinite clays establishes a suspension that increases the effective surface area and resists the flow in a pore, thus decreases permeability [46].

4.1.2. Physics of Fines Retention

It is essential to know the microscopic pattern of retained fine particles as the basis for clogging models, which strongly controls the capability to predict the extent of formation damage. The retention's primary impact is to occupy a part of the space earlier available to flow, reducing the average porosity of the porous medium.

Several retention mechanisms bring migrating particles into contact with retention sites such as pore surfaces, pore throats, and dead-end (crevice and cavern) spaces [7]. The fundamental retention mechanisms, as depicted in Figure 9, include size exclusion, mechanical and hydrodynamic bridging, surface deposition, sedimentation, direct interception, inertial impaction, sorption, and Brownian diffusion [7, 12, 26, 37, 84, 85, 86, 87, 88]. In the case of fine particle migration within porous media, the retention of fine particles in pore throats significantly damages the permeability.

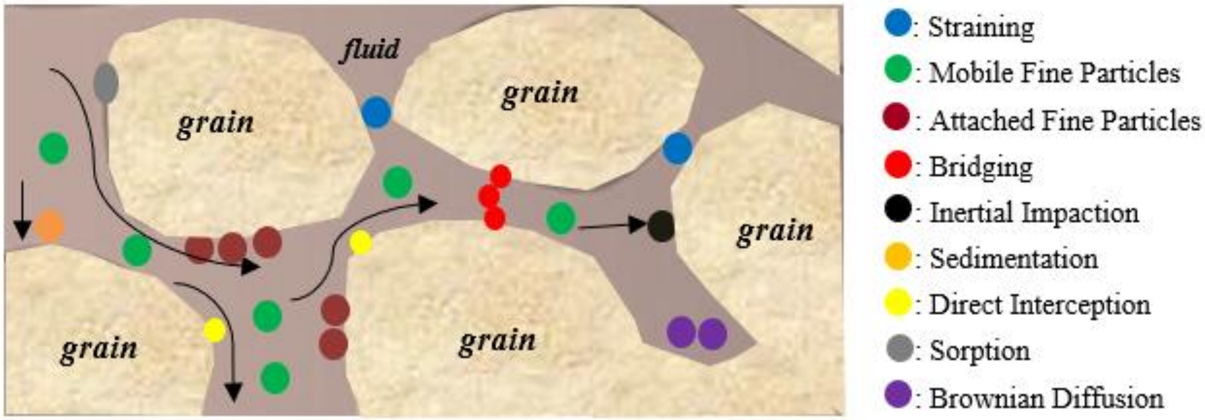


Figure 9. Different mechanisms of particle retention in porous media.

In addition to forces acting on a fine particle attached to pore surfaces, a moving particle within a carrier fluid also experiences inertial forces. Inertial forces effect is significant in high and spatially varying velocities by radial flow around the SAGD well, converging toward the screen openings [12]. In such conditions, fine particles tend to maintain their trajectory where flow streamlines suddenly change in the completion zone. Consequently, it is more likely that particles deviate from the flow streamlines, impact the pore walls, and retard in the completion zone [12]. This mechanism, known as inertial retardation or inertial impaction, leads to a gradual accumulation of fine particles on pore spaces and pore throats in the restriction zone [12]. In another condition, the screen can discharge the retained particles on pore walls over time, and the reduced retained permeability of the completion zone is recovered [13]. The macroscopic modeling should account for this behavior by incorporating appropriate kinetics for the retention and release of fine particles.

4.2. Macroscopic View

Continuum models can be employed to predict the macroscopic distribution of migrating and retained particles to estimate the permeability variation. The location and extent of fines deposition are deemed consequences of the interplay between convective, diffusive, release, and retention fluxes. These interactions are described by a convection-dispersion equation described by Equation (9). The governing equations describing the fines migration process in porous media at single-phase flow conditions consist of several equations. These equations are momentum (Darcy's law) equation, mass balance equations for water and mobile particles (Equations 8, 9), kinetic equations for release and plugging rates, porosity variation equation, and an empirical expression for permeability variation.

$$\frac{\partial[\varphi\,(1-C_m)\,\rho_w]}{\partial t}+\nabla\cdot[(1-C_m)U\,\rho_w]=0 \qquad ,\ U=\ \frac{k}{\mu}\nabla P \tag{8}$$

$$\frac{\partial(\varphi\,C_m+\sigma_a+\sigma_p)}{\partial t}+\nabla\cdot(U_s\,C_m-D\,\nabla C_m)=0 \quad ,\ U_s=\alpha\,U \tag{9}$$

where, C_m is mobile fines concentration [volume/pore volume], σ_a is the concentration of fine particles attached to pore surfaces [volume/bulk volume], σ_p is the concentration of fine particles plugged in pore throats [volume/bulk volume], φ is the instantaneous porosity of the medium, D is dispersion coefficient, U is Darcy velocity, and α is drift delay factor. The terms $(\partial\sigma_p/\partial t)$ and $(\partial\sigma_a/\partial t)$ account for the kinetics of pore throat plugging and pore surface attachment mechanisms, respectively. More precisely, $(\partial\sigma_a/\partial t)$ reflects the net rate of attachment of fine particles to the pore surfaces, considering the release and reattachment mechanisms. The concentration of retained particles at pore throats is responsible for high-pressure drops and permeability reduction during the process. Usually, the relative variation of permeability to the initial permeability is expressed as a function of release and retained particle concentrations by an empirical equation [9, 11, 34].

Numerous researchers introduced different empirical kinetic equations accounting for the rate of release and retention of fine particles on pore surfaces and pore throats due to hydrodynamic and chemical effects [7, 8, 9, 14, 25, 89, 90, 91, 92]. Tables 4 and 5 summarize the most critical mechanisms of the fines migration process as the kinetic equations for pore surface release and pore throat plugging mechanisms, respectively.

According to the kinetics equations, the release rate is proportional to the difference between the current and critical values of driving forces depending on velocity and salinity. Moreover, the plugging rate is proportional to convective flux $(U\,C_m)$ of mobile fine particles. Most of the plugging rate equations also account for the effect of accumulation of fine particles behind the previously plugged particles by considering a term $(\lambda_b\,\varphi$ or $\lambda_b\,\sigma_p)$ as a linear function of porosity or plugging fines concentration.

Civan [14] provided an excellent theoretical explanation about various processes of fine particles in porous media, including pore surface release, pore surface retention, pore throat release, and pore throat plugging. The most recent equations by Civan [14] include additional empirical parameters accounting for heterogeneities related to pore structure and pore surface properties.

Table 4. Pore-surface release rate equations (U_{cr} is critical superficial velocity, υ_{cr} is critical interstitial velocity, $\Delta\sigma_a$ is the concentration of released particles, σ_{ao} is initial attached fines concentration, σ_{cr} is critical retention concentration, T is temperature, γ is salinity, γ_{cr} is critical salinity, λ_p and λ_d are rate coefficients and λ_b , η , $m1$, and $m2$ are empirical constants)

Reference	Kinetic Equation
Khilar and Fogler,1983 [8]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\sigma_a$
Gruesbeck and Collins,1982 [25]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,\sigma_a(U - U_{cr})$
Civan and Nguyen, 2005 [90]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,(\eta\,\sigma_a)\,\varphi^{2/3}(\tau - \tau_{cr})$
Wang and Civan, 2005 [91]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,\sigma_a(\upsilon - \upsilon_{cr})$
Bedrikovetsky, 2010 [9]	$\Delta\sigma_a = \sigma_{ao} - \sigma_{cr}\ ,\sigma_{cr} = \sigma_{cr}\,(\upsilon,\gamma,pH,T)$
Kord et al., 2014 [92]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,\sigma_a(\upsilon - \upsilon_{cr})$
Civan, 2016 [14]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,(\eta\,\sigma_a)^{m1}\,\varphi^{m2}(\upsilon - \upsilon_{cr})\,(\gamma_{cr} - \gamma)$
Coranado et al., 2017 [93]	$\frac{\partial\sigma_a}{\partial t} = -\lambda_d\,U(\sigma_a - \sigma_{cr})$

Table 5. Pore-throat plugging /bridging rate equations

References	Kinetic Equation
Herzig et al.,1970 [7]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\,UC_m$
Gruesbeck and Collins,1982 [25]	$\frac{\partial\sigma_p}{\partial t} = \left(\lambda_p + \lambda_b\,\sigma_p\right)U\,C_m$
Civan and Nguyen, 2005 [90]	$\frac{\partial\sigma_p}{\partial t} = \left(\lambda_p + \lambda_b\,\varphi\right)U\,C_m$
Wang and Civan, 2005 [91]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\left(1 + \lambda_b\,\sigma_p\right)C_m\,\varphi\,U$
Lohne et al., 2010 [94]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\,\upsilon\,C_m$
Kord et al., 2014 [92]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\left(1 + \lambda_b\,\sigma_p\right)C_m\,\varphi\,(\upsilon - \upsilon_{cr})$
Civan, 2016 [14]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\left(1 + \lambda_b\,\sigma_p\right)U\,{C_m}^{m1}\varphi^{m2}$
Coranado et al., 2017 [93]	$\frac{\partial\sigma_p}{\partial t} = \lambda_p\,UC_m(1 - \sigma_a/\sigma_{cr})$

According to the kinetics equations, the release rate is proportional to driving forces as the difference between the current and critical velocity and salinity values. The plugging rate is also proportional to convective flux ($U\ C_m$) of mobile fine particles.

It is stated that the kinetic equations for the release mechanism cannot support the experimental results of abrupt variation in permeability caused by abrupt changes in flow rate or salinity [9, 11, 95]. They result in the prediction of permeability behavior with delay as time goes to infinity. Bedrikovetsky et al. [9] substituted the classical release rate equations with an alternative model that supports the abrupt permeability responses observed in coreflood tests. The authors introduced a phenomenological function known as critical retention (attached) concentration depending on velocity, salinity, pH, and temperature. The fine particles are detached until the attached concentration reaches a critical retention concentration upon changes to flow conditions. An instantaneous release process is assumed for hydrodynamic release, but a delay time factor is considered for the chemical effect [11, 34]. The critical retention concentration was derived based on the torque balance of attaching (electrical and gravitational) and detaching (lifting and drag) forces exerted on a fine particle attached to pore surfaces. Some simplified theoretical expressions of this function have their limitations and complexities in calculating input parameters [11]. Nevertheless, in modeling applications, the difference of critical retention concentrations in two different flow conditions (current and previous velocity and salinity conditions), known as the released particles' concentration, is determined by matching the experimental data [11, 34, 96].

In recent modeling studies, a drift delay factor (α) as the ratio of mobile fine particles velocity and fluid flow velocity is incorporated into the fine particles transport and plugging equations [9, 11, 34, 87, 96, 97]. This factor is attributed to fast and slow velocities of moving particles in the bulk flow and close to pore surfaces, respectively. Long-term stabilization of permeability after many pore volume injections in coreflood tests justify this parameter [11, 96].

4.2.1. Porosity and permeability variation

The instantaneous porosity of the porous media can be given based on the volumetric concentration of released and plugging fine particles:

$$\varphi = \varphi_o + (\sigma_{ao} - \sigma_a) - \sigma_p \tag{10}$$

where, φ_o is the initial porosity, σ_p is plugging fines concentration and the term $(\sigma_{ao} - \sigma_a)$ is released fines concentration.

Several empirical expressions have been proposed for the permeability variations relative to initial permeability based on porosity and concentration of plugging particles [7, 10]. The frequently used equation in recent fines migration studies is based on 1) the assumption of small release and plugging fines concentrations, and 2) considering the zero and first terms of a Taylor series expansion of permeability variation, as follows [9, 11, 34, 93]:

$$\frac{K(\sigma_a, \sigma_p)}{K_o} = \frac{1}{1 + \beta_a(\sigma_a - \sigma_{ao}) + \beta_p \sigma_p} \tag{11}$$

where K is the instantaneous permeability, K_o is the initial permeability, and β is the formation damage coefficient. Parameters β_a and β_p are formation damage coefficients because of attachment and plugging of fine particles at pore surfaces and pore throats. These parameters depend on particle and pore size distribution, and then they are a function of released and retained concentrations. However, for small release and retention concentrations, they can be assumed constant [34]. For the case that the effect of release term $(\sigma_a - \sigma_{ao})$ is significant, permeability increases. In an experimental-based modeling approach, the measured pressure drops and produced fines concentration data can be matched with simulation data by solving corresponding reverse problems to determine the empirical parameters.

5. Proposed Conceptual Workflow for Sand Control Design in Unconsolidated Sands

Experimental studies under representative conditions are essential to select the optimum design configurations before running the screen in the well. The sand retention test (SRT) equipment with various features, sizes, and testing procedures is used to evaluate sand control and flow performance of a sand control screen [64, 68].

Most of the previous SRT experiments partially investigated the fines migration inside the porous media. The screen evaluations are performed based on sand production and retained permeability measurements in a testing that allows for quick flow stabilization. Performing a series of time-lapse experiments and visual inspection of the slots indicate that sand grains alone do not plug the slots. The infill and tight packing of fine particles around the sand grains adjacent to the slots have been found to induce low retained permeabilities [21].

More recently, an SRT setup (Figure 10) has been frequently used to assess various screen configurations considering measurements of the produced and retained fine particles. The tests, however, neglect the interaction of fines migration with other formation damage mechanisms, including chemical (organic and inorganic scaling, clay swelling) and thermal damages (mineral transformation, dissolution), and also liner fouling, are not considered in a sand retention test.

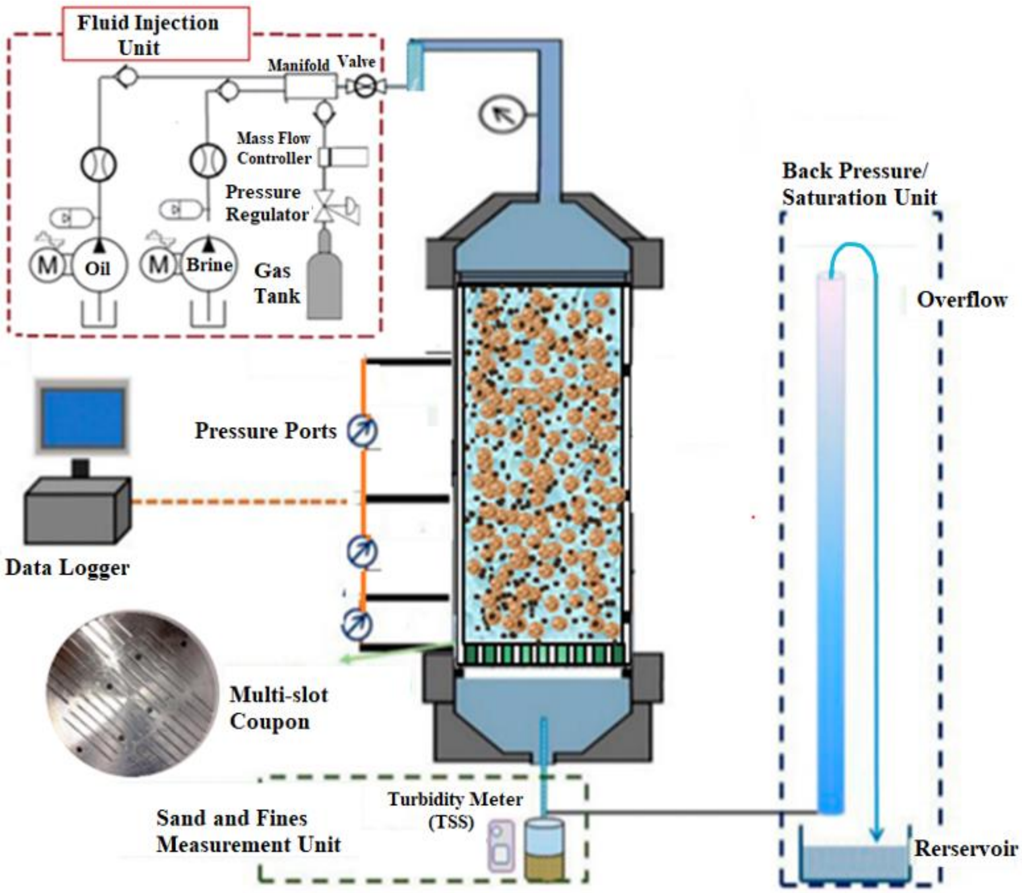


Figure 10. Linear flow Large-Scale Sand Retention Test (SRT) setup [35, 56, 49, 53, 57, 58].

The setup provides linear single-phase and multi-phase flow tests. The sand sample is packed on a 6-inch screen coupon up to 17 inches in length. A small axial load is just applied to prevent the fluidization of the sample. This packing procedure emulates the case of the rapid collapse of formation sand over the screen (zero effective stress) in SAGD wells during the early life of the well before stress evolution [64, 68]. Multi-slot coupons of slotted liners can be used to assess the effect of slot density instead of previous single-slot tests [64]. Although employing such a large-scale setup allows long-term flow conditions and also minimizes the boundary effects, it demands a large amount of reservoir formation sand and fines that may not be available or be costly. This issue is typically circumvented using commercial sands with a PSD and shape factor properties that match with natural oil sands [35, 64]. However, commercial sands' surface properties affect the fines migration process and may not represent natural oil sands.

The Fail/Pass criteria in the literature to select an optimum screen design are generally based on acceptable levels of sand production (less than 0.12 lb/ft^2 or 1% of slotted liner volume) and retained permeability (higher than 70%) [56, 64]. In some works, the optimum slot width inferred from single-slot SRT is presented as a function of specific points on the PSD of the sample [71]. A recent presentation is based on a color code similar to traffic light known as Traffic Light System (TLS). The TLS labeled with D values (e.g., D90 is the mesh size that 90% of particles have a diameter greater than this value) of the PSD allows to specify unacceptable (red), marginal (yellow), and acceptable (green) slot widths for different slot density and flow conditions [35]. In the current uses of TLS, lower and upper bounds of 0.12 lb/ft^2 and 0.15 lb/ft^2 for sand production and 50% and 70% for retained permeability are considered [35, 56, 71, 57]. Figure 11 demonstrates a typical TLS for the performance of different sizes of slotted liner coupons.

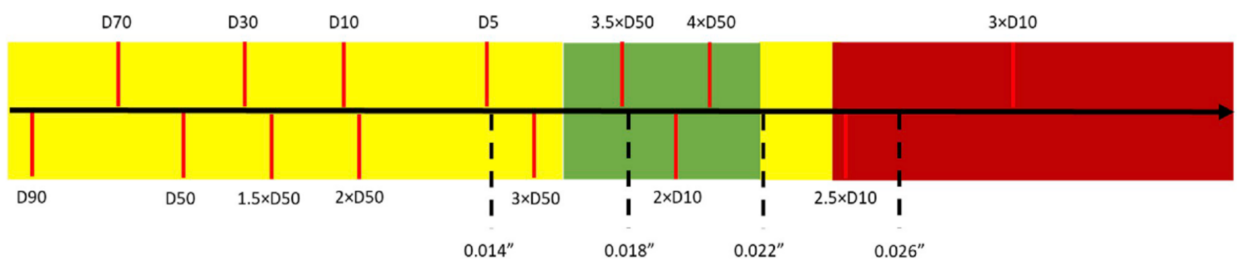
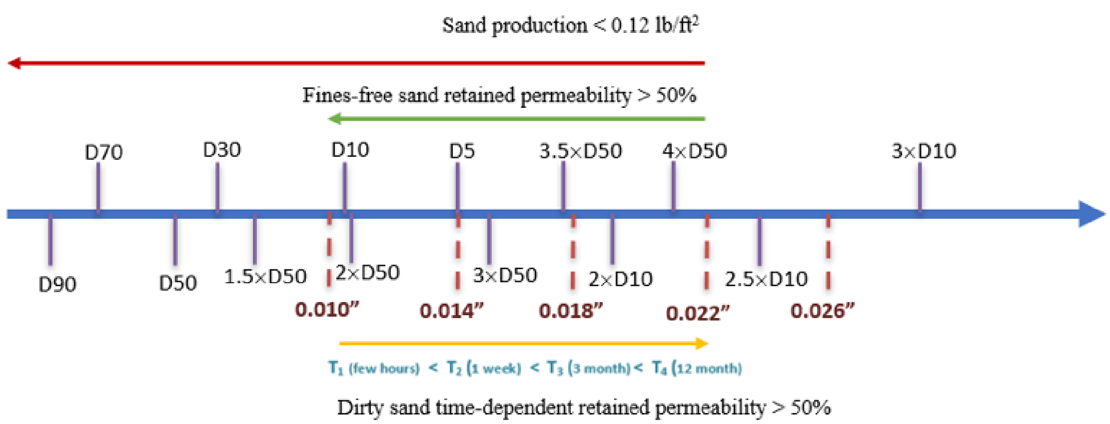


Figure 11. Traffic light system for slotted liners with different aperture sizes (dashed lines), slot density 30, and flow rate <0.72 bbl/day/ft [71]

The fines migration process in an SRT setup with a screen coupon can be simulated using a coupled 3D numerical model. The numerical model can evaluate the effect of different combinations of influencing factors under the representative rock and fluid properties. Conducting such an evaluation in a large-scale SRT setup is very expensive and time-consuming. The modeling's critical steps would be calibrating (to determine empirical parameters) and validating the model based on the experimental results. For this reason, appropriate physics governing the fines migration process should be incorporated. Because of the narrow screen apertures, the model would include a computationally extensive mesh, which requires an efficient calibration procedure. However, theoretically, the empirical model parameters are porous media characteristics and independent from the screen specifications. Therefore, they can be determined by matching experimental and simulation results for a specific sand pack with simple geometry without the screen coupon.

In a representative fines migration experiment, depending on the concentration of migrating and retained fine particles in the completion zone, the short-term retained permeabilities may increase or decrease. If migrating fine particles are accumulated progressively in the completion zone, the retained permeability would decrease. In contrast, the retained permeability would increase if fines migration is insignificant or the fine particles near the screen are discharged [13].

As depicted in Figure 12, the screen design for dirty sands (sands with high fine contents) based on the short-term evaluations can be misleading. For clean sands, typically, the smallest aperture size which passes the retained permeability constraint would be chosen (e.g., 0.014" in Figure 12) [35, 71]. However, for dirty sands, the smallest aperture size would be plugged drastically after a while, owing to fines migration. It is reasonable that wider aperture sizes are chosen, which would plug in a much longer time (e.g., 0.022" in Figure 12). Therefore, based on short-term retained permeability evaluation, an aperture size may be selected that is more narrow for better sand retention performance but not wide enough to discharge fine particles in the long-term.



Red: Acceptable slot sizes with respect to sand production stabilized in the short term for both fines-free and dirty sands.

Green: Acceptable slot sizes with respect to sand production and retained permeability stabilized in the short term for fines-free sands. The retained permeability is affected by resorting and bridging of sand grains over the SCD. Smaller size is preferred for better sand control performance.

Yellow: Acceptable slot sizes with respect to sand production and retained permeability for dirty sands. The retained permeability is affected by combined effects of sand grains resorting/bridging and fines migration process. This is not a short term process (typically several days in lab and several months in field). Larger size is pereferd for long-term performance.

Figure 12. Demonstration of design constraints for fine-free and dirty sands.

To account for the screen's long-term flow performance in dirty sands, a workflow (Figure 13) is proposed based on the numerical simulation of the fines migration process. In the first stage, simulation is performed at the laboratory scale to match the experimental results and obtain the essential modeling parameters. Performing a laboratory-based numerical simulation in this scale allows for the incorporation of the SCD geometry. The contribution of SCD to the retained permeability evolution with time under fines migration process can be evaluated as a skin factor by conducting separate simulations with and without SCD. The second stage includes modeling the fines migration process on a well scale. The skin factor obtained from the previous stage will be applied here as SCD geometry will not usually be considered in well-scale modeling. In case of available field data of flow rate or pressure drop variations under fines migration process, the well scale model can also be calibrated to obtain more accurate model parameters, otherwise, the model parameters obtained from the laboratory scale can be applied. The near-wellbore modeling can be performed by implementing an efficient approach for coupled near-well and reservoir modeling [98]. In the last stage, the well model can be used to predict the retained permeability under the fines migration process and design SCD for the long-term life of the well based on the criteria earlier explained.

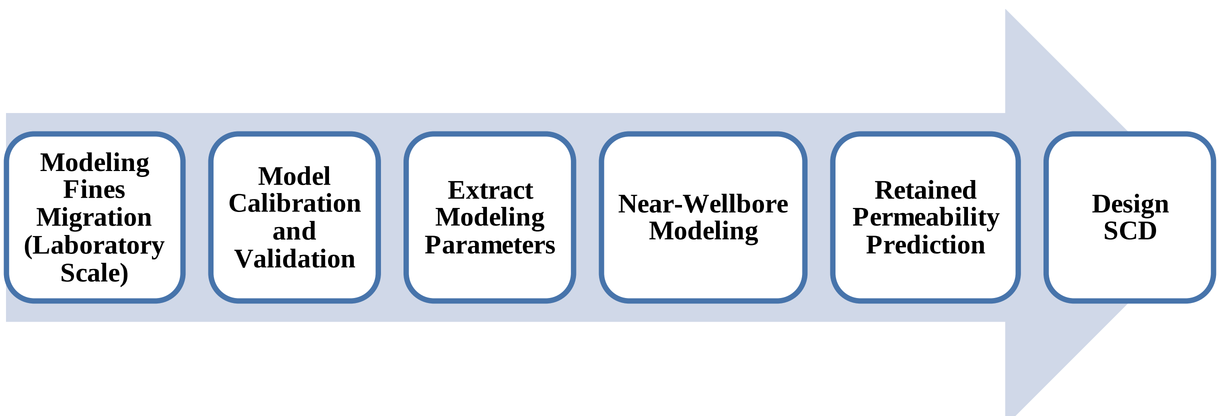


Figure 13. Proposed workflow for SCD design accounting for transient behavior of the fines migration process.

6. Summary

This paper reviews the fines migration process in porous media with particular attention to the SAGD near-wellbore region. Field observations and coreflooding experiments confirm the well productivity impairment and screen plugging in SAGD wells due to the fines migration process. Theoretical and experimental studies demonstrate the significance of particle and pore size distribution, flow velocity, salinity, pH, temperature, fines content, fines wettability, effective stress, and well completion on the fines migration process.

Macroscopic models have been frequently used in lab-scale studies to predict the macroscopic distribution of fine particles within the porous medium and estimate the permeability variation under the fines migration process. These models include empirical kinetic equations for different mechanisms of release and retention of fine particles within porous media. Some model parameters need to be determined by matching the experimental data. The past macroscopic models were mainly developed for consolidated sands and did not consider the interaction of the porous medium with the sand control screen.

The sand control screen's effect on the retention of fine particles in the near-wellbore sand and the production of migrating fine particles have not been adequately explored through a representative test procedure. The current sand retention tests for evaluating the sand control performance account for short-term pressure stabilization. However, they are not designed to incorporate the long-term interaction between the fines migration and other plugging mechanisms such as organic and inorganic scaling.

This paper also proposes an alternative workflow to investigate the long-term flow performance of the sand control device in sands containing fine particles. To implement the proposed workflow, numerical modeling of the fines migration process at the laboratory and wellbore scales is necessary. The mathematical model can also help investigate the effect of several combinations of contributing factors, which is expensive and time-consuming through SRT experiments.

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