A Novel Sand Control Testing Facility to Evaluate the Impact of Radial Flow Regime on Screen Performance and its Verification

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ABSTRACT

Optimum design of the sand control devices in oil sand reservoirs plays a vital role in minimizing the sand production and increasing the reservoir productivity in Steam-Assisted Gravity Drainage (SAGD) operations. Various sand control testing facilities have been developed to evaluate the performance of sand control screens, such as the pre-packed Sand Retention Test (SRT). Current testing apparatuses are based on the linear flow regime. However, fluid flow around SAGD production wells is radial flow, not linear. This study introduces a Full-scale Completion Test (FCT) facility to emulate the radial-flow condition in SAGD wells. Instead of using a disk-shaped screen coupon, this facility utilizes a cylindrical-shaped screen. A couple of tests were carried out to determine the flow uniformity inside the cell and identify the test repeatability. Test results show that flow is distributed uniformly inside the cell, and experiments are repeatable in terms of differential pressures, fines production, and sanding levels. Therefore, this innovative FCT experimental setup and procedure allows a more realistic evaluation of the liner performance by emulating the real SAGD flow regime around the liner. Testing results obtained from the FCT can be used to complement and validate the current testing procedures. These tools can be adopted for an objective custom-design and selection of standalone screens in SAGD.

Keywords: Sand Retention Testing, Full-scale Completion Testing Facility, Sand Control, Radial Flow, SAGD.

1. Introduction

Canada's proven heavy oil reserve is estimated to be around 171 billion barrels, which is the third-largest oil reserve in the world (Natural Resources Canada, 2019). The shallow oil sands, which are feasible for mining, cover roughly 20% of the total oil sands area. Thus, non-minable resources must be recovered by in-situ techniques (Burton et al., 2005).

In-situ thermal recovery by Steam-Assisted Gravity Drainage (SAGD) accounted for nearly 50% of total bitumen production (Butler, 2001). This technique is currently preferred as the primary method for in-situ heavy oil production (Bennion et al., 2009).

SAGD is an oil extraction technique for viscous bituminous reservoirs employing two horizontal wells in a target reservoir. High-temperature steam is injected into the reservoir through the upper

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well to reduce heavy oil viscosity. Then, due to gravity, emulsion composed of melted bitumen and condensate water flows toward the bottom well before being pumped out to the surface.

Sand production is considered as a significant problem in SAGD operations due to the nature of the unconsolidated oil sand formation where SAGD is operated. Sand control devices (SCD) are installed to prevent sand production in the SAGD process while controlling the flow of reservoir fluids into the wellbore. Slotted Liner (SL), Wire-Wrapped Screen (WWS), and Punched Screen (PS) are the main completion tools (Zhang, 2017; Montero et al., 2018). Among them, the SL is the most common as it is less expensive and offers satisfactory mechanical integrity and consistent performance (Bennion et al., 2009).

Conventionally, the design criteria for SCD's had been based on either empirical correlations or field experience. However, in recent years, a growing interest in employing sand control laboratory tests has been observed for the ideal selection and design of SCD's for SAGD operations. In this regard, two sand control testing procedures were introduced in the literature; slurry sand retention test (Coberly, 1937; Underdown et al., 2001; Hodge et al., 2002; Constien and Skidmore, 2006; Chanpura et al., 2011; Ballard and Beare, 2012), and pre-pack sand retention test (Markestad et al., 1996; Ballard and Beare, 2003, 2006; Bennion et al., 2009; Chanpura et al., 2011; Romanova et al., 2014; Devere-Bennett, 2015; Anderson, 2017; Wang et al., 2018, 2020a, 2020b, 2021; Montero et al., 2018; Fattahpour et al., 2018). The schematics of typical slurry testing and pre-pack sand retention testing setups are illustrated in Figures 1 and 2, respectively.

In the slurry testing, a low concentration slurry of sand and fluids (usually less than 0.1% in volume) is injected into an empty cell towards the SCD coupon to simulate the sand slurry flow in annular space between the borehole and SCD (Ballard and Beare, 2003; Chanpura et al., 2011). Montero et al. (2018) denoted that the slurry test does not simulate the related conditions for SAGD wells and is mostly useful for scab liner evaluation where a secondary SCD is installed inside a failed SCD. In contrast, in the pre-pack sand retention testing (SRT), the cell is filled with sand before fluids flow towards the SCD coupon. This test represents the scenario of the rapid collapse of the formation sand over the SCD at the early stage of the SAGD operation (Fattahpour et al., 2018). The pre-pack SRT is a better representation of SAGD condition as it has been employed in all testing approaches for sand control design in SAGD wells (Benion et al., 2009; Wang et al., 2018; Montero et al., 2018).

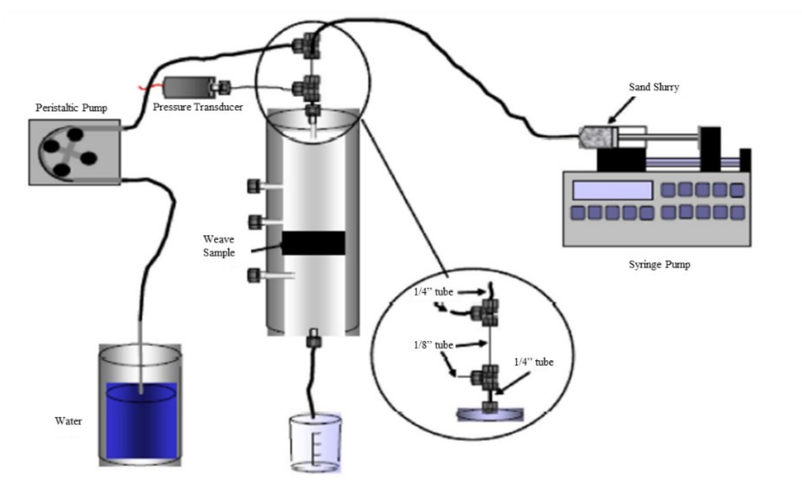

Figure 1. Typical schematics of a slurry-type sand retention testing facility (after Montero et al., 2018)

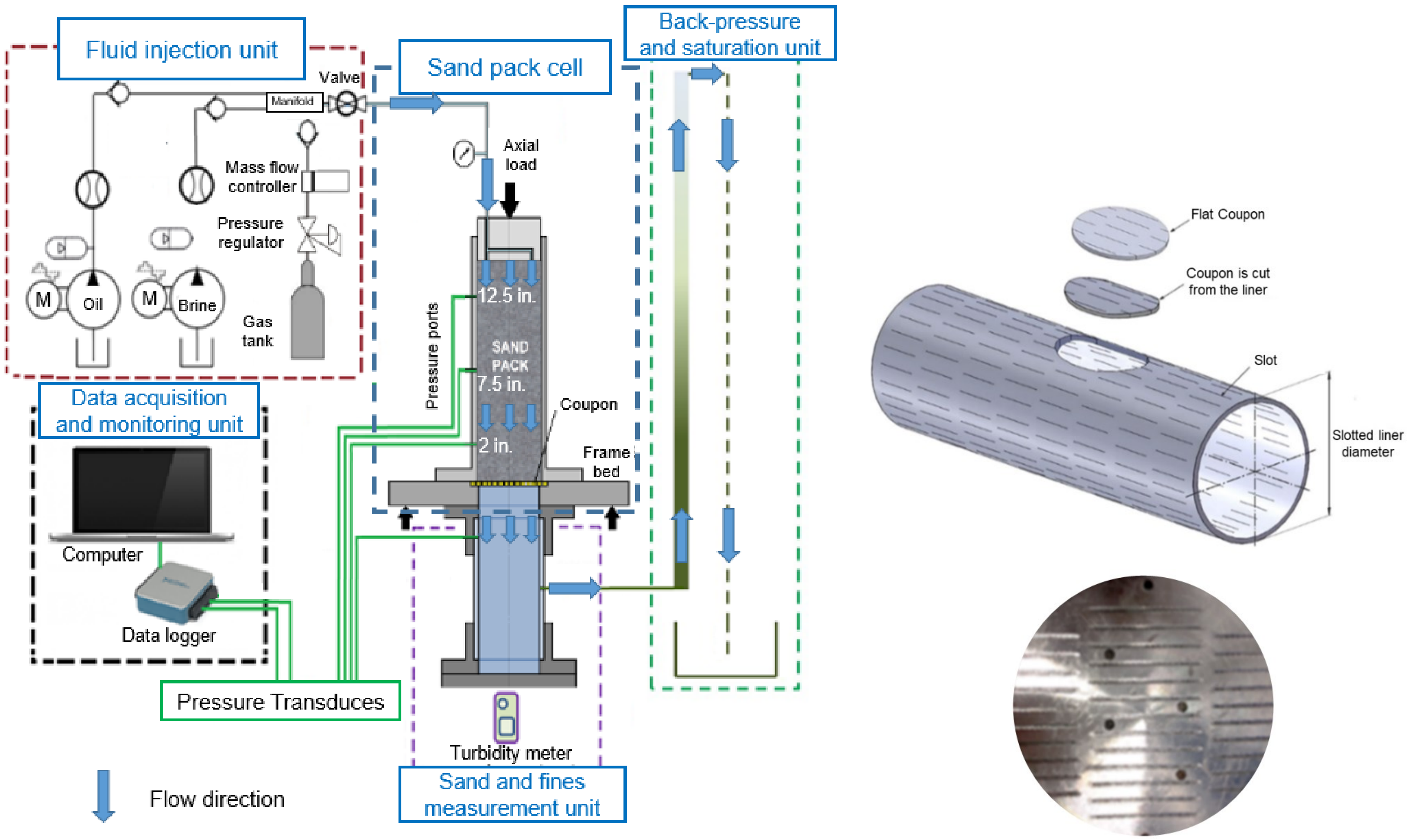

Figure 2. Typical schematics of a sand retention testing facility (Montero et al., 2020) and a coupon as a cut-out from a real screen

The primary purpose of the sand control tests is the simulation of the near-wellbore conditions as closely as possible. The experiments are simplified to a certain extent by employing some assumptions for practicality. Test assumptions should always be re-evaluated to enhance its consistency with real-world conditions. One of the main simplifications in the current SRT practices is the development of linear fluid flow in the sand pack. In the SRT test, the liner coupon is placed at the bottom of the sand pack, and fluids are injected from top to bottom of the sand pack (Figure 2). This configuration only partially simulates the top position of the liner in a horizontal well because of the linear flow in the SRT. In contrast, the actual flow around the liner is radial (Figure 3b).

Different combinations of physical forces (i.e., gravitational force and hydrodynamic forces consisting of drag force and pressure gradient force) act on sand grains around the wells (Figure 3). In a vertical wellbore, hydrodynamic forces (F_d) are the only forces pushing the grains toward the liner, and gravity force (W) tends to hold the grains in their place (Figure 3a). In horizontal wellbores, however, the role of gravity force changes depending on the position around the wellbore (Figure 3b). For instance, the gravity and drag forces add up to push the sand grains located above the screen towards the wellbore. At the bottom of the screen, however, the gravity force resists against the hydrodynamic forces and reduces the possibility of sand production. As such, it is essential to account for the flow configurations and their impact on not only sanding but also fines migration and plugging in the testing. The use of linear flow in the SRT experiment is not fully able to represent the SAGD wells conditions in terms of radial flow and the role of gravity in the production of sand and migration of fines.

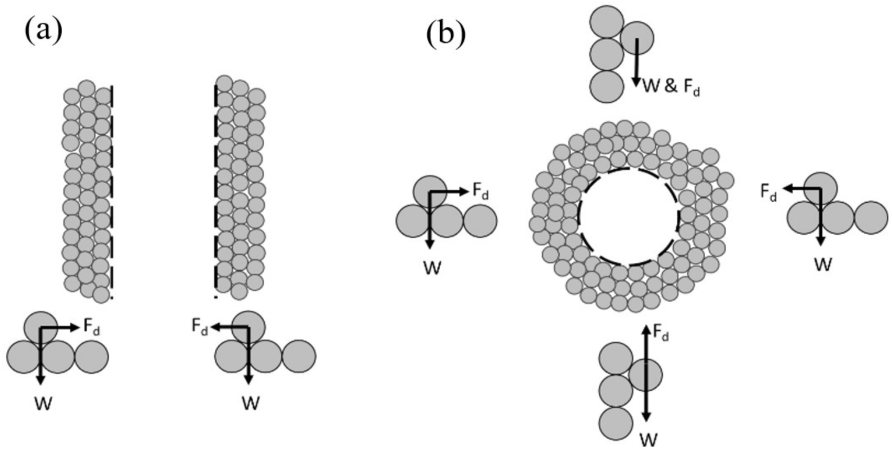

Figure 3. Physical forces acting on grains around the a) vertical, and b) horizontal wellbore in an unconsolidated oil sand reservoir

In current test setups, due to the cylindrical shape of the sand pack and flat coupon at the bottom, the flowing area is constant, which causes constant flow velocity along the sand pack. As a result, fines migration occurs over the entire length of the sand pack (Mahmoudi et al., 2017), which is not realistic. In the radial flow regime, flow velocity increases close to the liner because the open area to flow decreases as the wellbore is approached. Therefore, the expectation is to see lower or no fines migration far from the liner owing to the weaker drag forces generated by smaller fluid velocities. Valdes and Santamarina (2006) displayed that thick radial bridges can be developed due to the fine particles retardation as the flow converges. These radial bridges would increase the stability of the formation and reduce the production of solid particles.

In the context of conventional oil and gas production, experiments with radial flow geometry have been widely employed to investigate standalone screens' performance, sanding criteria, and perforation collapse using the hollow cylinder and thick-walled cylinder tests (Van den Hoek et al., 1996, Papamichos et al., 2001, Nouri et al., 2005, Chenault, 1938, Jin et al., 2012, Anderson 2017, Dong et al., 2017, Ma et al., 2020). Nearly a century ago, Chenault (1938) employed a radial-flow cell assembly to compare fluid flow rates with and without screens for conventional well operations. Qi (2004) designed a large-scale testing setup with the radial flow to simulate sand production and compare the performance of pre-packed screens versus gravel packing. The outcome was a relationship between sand production and some testing parameters such as fluid viscosity and flow rate. Papamichos et al. (2001) and Nouri et al. (2005) performed hollow cylinder tests to investigate the sanding level and failure of the perforation in the formation surrounding the wellbore while a high flow rate is pumped from the outer surface of the specimen toward the central hole.

Jin et al. (2012) evaluated the performance of several sand control screens for gas wells by developing a large-scale laboratory testing apparatus with radial flow. The gas was injected into the sand pack sample, packed around a 12-inch-length liner. Dong et al. (2017) and Ma et al. (2020) established experimental setups to assess the screen performance where a sand slurry was radially injected into the cell from two injection ports at the outer boundary towards the screen. There is an uncertainty in the uniformity of flow in their experiments due to the limited numbers of the injection points.

Anderson (2017) introduced a large-scale testing apparatus for sand control testing. Instead of using a single-slot coupon, Anderson (2017) utilized a cylindrical screen with a diameter of seven inches. He installed the liner at the bottom of the sand pack and injected the fluids from top to bottom. In this facility, sand is packed on almost one-third of the screen as a curved coupon, which only includes the top part of the liner. Their study aimed to compare the results of small-scale testing on single-slot coupons with the ones obtained from large-scale testing apparatus on a portion of the liner. They concluded a good agreement between the results of small- and large-scale testing facilities (Anderson, 2017). The assumption was that the flow geometry would develop to a radial flow as the liner is approached. However, due to the same cross-sectional area of the sample from top to bottom and the liner located at the bottom of the sample, the radial flow would not be fully developed. Instead, the flow geometry would be linear that would only deviate from linear flow close to the curved liner.

A review of the existing testing setups for sanding indicates that most of the facilities with the radial flow have been mainly developed for conventional well applications. The radial flow regime has not been fully incorporated in the thermal recovery context. It is essential to investigate the screen performance in the radial flow configuration to be more representative of the SAGD wells in terms of flow geometry.

This paper describes a Full-scale Completion Testing (FCT) facility and the testing procedure for sand control testing in the SAGD context. This equipment is introduced as an advanced testing facility for better simulation of the SAGD reservoirs in a radial flow regime. Several challenges were encountered when developing the testing facility and procedure, which were mitigated. Such matters are briefly discussed in this paper.

2. FCT Equipment

Full-scale Completion Testing (FCT) equipment is a novel testing device to simulate a radial flow regime around the liner in the SAGD production wells. The setup accommodates a sand pack supported by a liner in either the horizontal or the vertical direction. A schematic of the FCT facility with a vertical liner is shown in Figure 4. Instead of using a flat or curved screen coupon in the existing devices, the FCT facility houses a cylindrical shape screen in the middle of the sand pack. The fluids are injected at the room temperature into the sand pack from several ports located at the circumference of the testing cell to generate a uniform flow from the outer side of the sand pack radially toward the liner.

As shown in Figure 4, the FCT apparatus includes five major units: (1) sand pack cell, (2) fluid injection unit, (3) data acquisition and monitoring unit, (4) sand and fines measurement unit, and (5) back-pressure unit.

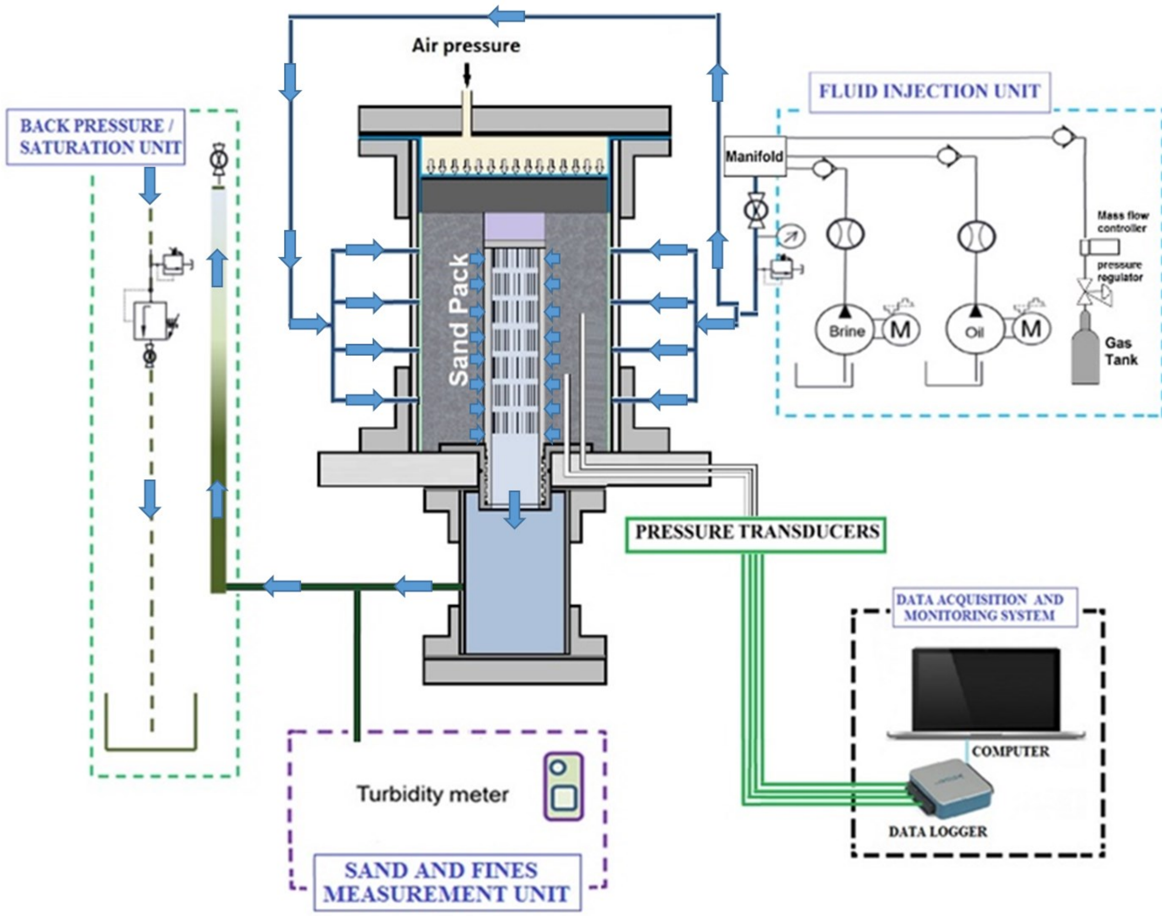

Figure 4. Full-scale Completion Test Facility (FCT); (blue arrows show the flow direction during the test)

2.1. Sand pack Cell

The sand pack cell is a hollow cylinder with an inside diameter of 12 inches and a length of 19 inches to contain the screen prototype. A slotted liner prototype with an outer diameter of 3.5 inches and a height of 12 inches is installed. This setup allows analyzing different SCD's by placing any type of liner or screen (e.g., slotted liner, wire-wrapped screen, or punched screens) with a diameter of 3.5 inches at the center of the cell. The sand is packed layer by layer using the moist packing method around the screen. As the cell is made of PVC, the maximum allowable pressure applied axially to the sand pack is about 40 psi for the safe operating conditions.

The cell and screen are placed on an aluminum base plate with a hole at the center to screw the liner. This hole also guides the produced fluids and sand particles to the sand trap. The cell can be rotated to perform the sand retention test with the screen pipe in the vertical or horizontal direction.

A specially designed diaphragm is placed at the top of the sand pack to apply axial load using air pressure. As the magnitude of axial load can affect the test results (Guo et al., 2018, Wang et al., 2018), a pressurized diaphragm applies and keeps constant stress at the top of the sand pack. The axial load, which is parallel to the screen, would induce a corresponding lateral stress perpendicular to the liner. The low magnitude stress on the screen corresponds with near-zero stress at early SAGD stages when formation sand collapses over the screen (Montero et al., 2018). The axial stress is required to (1) compact the sample, (2) avoid channelling in the sand pack, (3) prevent sand fluidization during the saturation phase, and (4) apply normal stress on the screen corresponding to the normal stress on the screen in the well.

2.2. Fluid Injection Unit

The fluid injection unit includes two pumps for oil and brine injection. Both pumps are capable of injecting brine and oil to the FCT cell at different flow rates. Two layers of geotextile and one layer of steel mesh are installed at the outer side of the sand pack to uniformly distribute the flow into the sand pack toward the screen at the center of the testing cell. The injected fluid flows out of the system through a back-pressure column. The produced fluid passing through the back-pressure column is collected at specific times to determine the flow rate at each stage.

2.3. Data Acquisition and Monitoring Unit

The data acquisition and monitoring unit consists of up to eight differential pressure transducers with 0.25% accuracy, a data acquisition system (LabVIEW), and a rotameter. The differential pressure transducers are used to record the pressure drop along the sand pack at different locations around the liner to analyze the permeability variations due to fines migration.

Six transducers were installed for the tests in this paper. These transducers were connected to narrow steel pipes that are installed inside the sand pack at three heights of 3.5, 6.5, and 9.5 inches from the bottom and two radial distances of 3 and 3.6 inches from the liner center. Each differential pressure transducer recorded the pressure difference between a specific location inside the sand pack and an individual pressure port inside the liner. Each differential pressure transducer is explicitly labelled, including a letter and a number (Figure 5). Ports with A and B letters are located at a radial distance of 3.6 in. (far) and 3 in. (close) from the liner center, respectively. Numbers 1, 2, and 3 indicate the vertical locations of transducers at levels of 9.5, 6.5, and 3.5 inches from the bottom, respectively. For instance, port A2 is located far from the liner at the height of 6.5 inches from the bottom.

The data acquisition device was utilized to collect and record signals from pressure transducers through LabVIEW Signal Express software. The rotameter was installed to record the fluid flow rate at the outlet. The volume of produced brine is measured every 10 to 15 minutes to control the fluid flow rate.

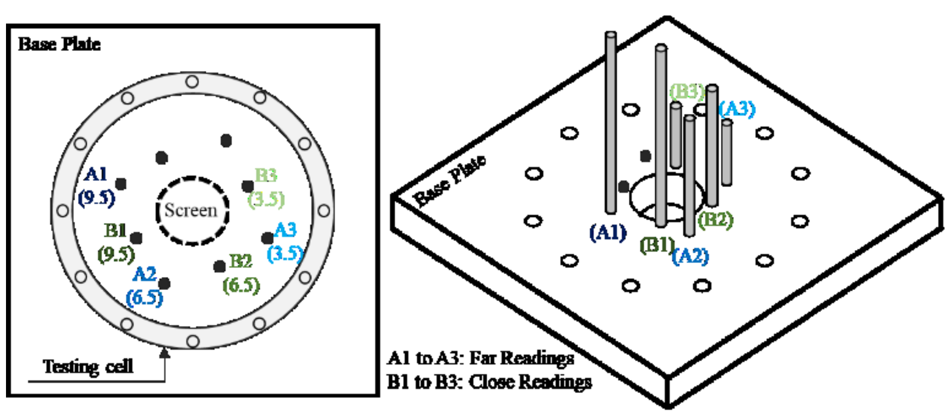

Figure 5. Schematic of the pressure port locations around the liner and their labels; top and side view (the numbers below each label is the height of the pressure port in inches)

2.4. Sand and Fines Measurement Unit

The sand and fines measurement unit consists of a specially designed sand trap to capture the produced sand and fines. The sand trap is placed at the center of the bottom side of the base plate.

A narrow tube is installed beneath the central hole of the base plate to collect 100-cc of outflow samples at certain time intervals. A metering needle valve is connected to control the flow rate coming out of the pipe to avoid pressure disturbance inside the sand trap when collecting the samples. The PSD of the produced fines is analyzed using a laser particle size analyzer. Besides, the mass of the produced fines is calculated based on the measured fluid turbidity using a turbidimeter device. Particles smaller than 44 microns is considered as fines particles (Abram and Cain, 2014).

2.5. Back-Pressure Unit

The back-pressure unit is used to generate a minor back-pressure (3.25 psi) on the sand pack during the saturation and flow phases. Low flow rates are introduced into the sand pack during the saturation phase through this back-pressure column to avoid the viscous fingering phenomenon.

3. Testing procedure

3.1. Flowing Fluid

Sodium Chloride brine with a salinity of 400 ppm, and a pH of 7.9 was used as the injection brine phase. A review of the chemical properties of the produced water in SAGD wells shows 400 ppm as the lowest salinity value and 7.9 as a usual pH level (Cowie et al., 2015; Mahmoudi et al., 2016b; Birks et al., 2017; Haftani et al., 2019).

3.2. Slotted Liner

The testing here used a rolled top slotted liner with a diameter of 3.5 inches. Due to the rolled top profile of the slots, the outer and inner aperture sizes are 0.022 and 0.028 inches, respectively. Slots are manufactured in four columns, including 18 slots per column.

3.3. Sand pack Preparation

For the sand pack preparation, commercial sands and clays are mixed to achieve a similar Particle Size Distribution (PSD) to that of the McMurray Formation. Abram and Cain (2014) categorized PSD types of this formation in Alberta, Canada, into four major groups, DC-I as the finest to DC-IV as the coarsest oil sands. Devere-Bennett (2015) determined the compositional fraction of the existing clay materials in the core samples from the McMurray Formation's oil sands, which are 64.5%, 23.3%, and 11.3% for kaolinite, illite, and smectite, respectively.

In this study, the DC-I type of PSD from the McMurray Formation was replicated by mixing two commercial sands and a commercial clay. Mahmoudi et al. (2016a) showed the shape factors (sphericity, angularity, and aspect ratio) of the commercial sands employed in the sand pack preparation are comparable to the same for the oil sand particles. Therefore, they could be used for replication of the real formation sands for large-scale laboratory testing (Mahmoudi et al., 2016a). XRD analysis of the commercial clay shows 67wt% is kaolinite, and 28wt% is illite, and the rest is mainly quartz. The composition is comparable to the same reported by Devere-Bennett (2015) for the McMurray Formation, except it is missing the smectite clay. Figure 6a shows the PSD curves of the commercial sands, and Figure 6b illustrates a reasonable agreement between the PSD curves of actual and replicated DC-I.

The sand pack was prepared from 38 kg of commercial sands and clay mixed with 10% brine by weight (41.8kg in total). Moist tamping method was used to pack the sand layer by layer (3,656 g and height of 1.4 in/layer) inside the cell to reach an average porosity of about 37%. After packing, 25 psi axial stress was applied over the sand pack by pressurizing the diaphragm. Finally, the sand pack was saturated from bottom to top by applying 3.25 psi back pressure using the back-pressure column from bottom to top. De-airing of the cell and pressure measurement pipes were meticulously done. In the end, the sand pack was left overnight to ensure that the sample is fully saturated.

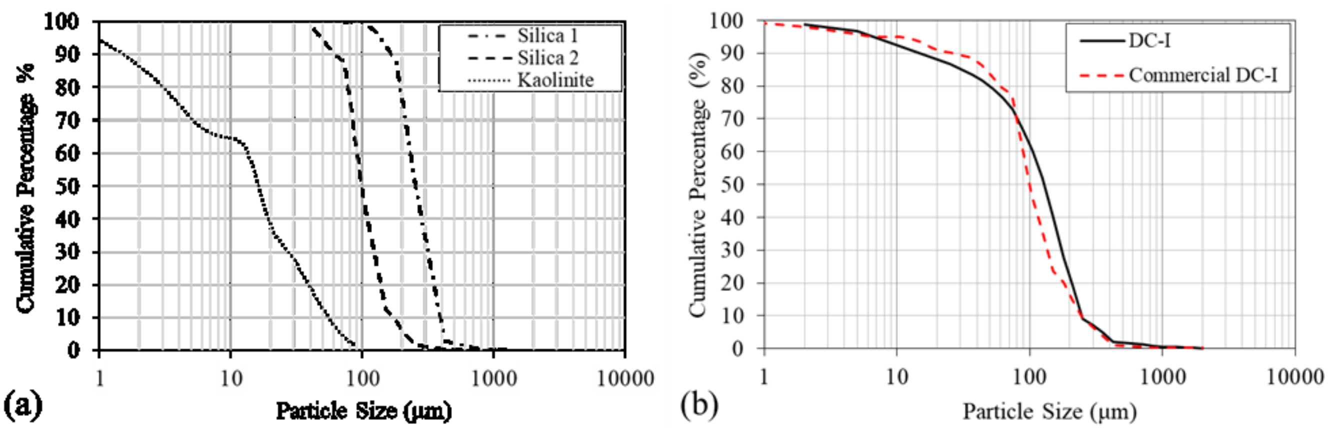

Figure 6. a) PSD curves for three commercial sands, and b) PSD curves for original DC-I (Abram and Cain, 2014), and replicated DC-I from the commercial sands

3.4. Single-phase Brine Injection Scenario

The liquid flux rate for a typical production rate of 2,000-4,000 bbl/day for the SAGD wells with a length of 700-1000 m completed with a 7-inch slotted liner would be in the range of 0.33-0.95 bbl/day/ft^2. For the liner with the area of 0.92 ft^2, this range would be 0.3-0.87 bbl/day per square feet of the liner.

Plugging of sand control devices as a result of scale deposition, corrosion products, and fouling by fines deposition can cause up to 90% of the slot plugging (Romanova and Ma, 2013). Besides, the non-contributing sections due to liner connections of the sand control completion could be approximately 20% of the well length. Therefore, considering the highest flow rate, non-contributing sections and different levels of plugging, the flow rates were calculated to simulate the SAGD reservoir production flux rates at the laboratory scale to test the slotted liner coupon in the current study (Figure 7). The testing in this paper uses single-phase brine as the flowing fluid, although the setup is equipped to establish a multi-phase oil-brine-gas flow.

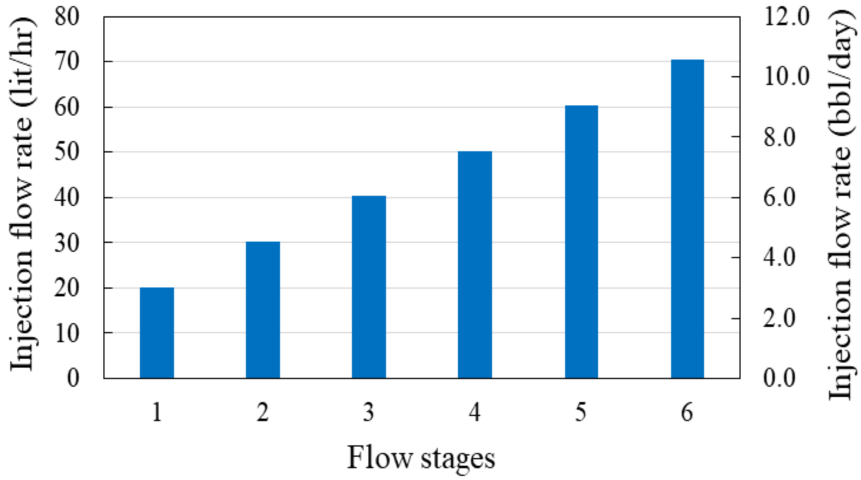

Figure 7. Step rate flow for single-phase brine injection during the FCT

4. Testing Results

The FCT facility is unique in the field of sand control testing, which is developed to capture the radial flow condition in SAGD wells. The fluid flow in the test follows a radial geometry, which is in contrast to linear flow in the current SRT facilities. After conducting several tests to identify and mitigate the limitations of the FCT facility, the final setup was employed in this study to determine the uniformity of the flow inside the sand pack and repeatability of the test results.

Two single-phase pre-pack FCT's were performed to evaluate the capability of the new setup in the evaluation of the SCD for the radial flow regime. Different sets of data were recorded during the test to provide reliable information to show whether this facility appropriately works and test results are repeatable. The recorded data are differential pressure, sand pack permeability, fines concentration inside the sand pack, produced sand and produced fines concentration in discharged water.

4.1. Uniformity of flow

Uniform flow distribution inside the sand pack is essential to ensure that the testing apparatus is appropriately working. Different indicators, such as pressure distribution and fines concentration inside the sand pack, were observed to determine the state of flow uniformly along the liner. This section provides experimental results to demonstrate that flow channelling and non-uniform flow conditions do not happen inside the sand pack.

4.1.1. Differential Pressure data

As stated in Section 2.3, pressure differences were recorded at each stage between the 6 measurement points located around the liner and a point inside the liner. Each flow stage was kept constant for 15min to ensure that the flow fully stabilizes. The flow is observed to stabilize after about 3 to 7 minutes as determined from the stabilized pressure differentials. Figure 8 illustrates the stabilized pressure differentials for the second stage of Test#2 (30 lit/hr).

Pressure differences at different locations inside the sand pack are shown in Figure 9. As expected, higher differential pressures were recorded for higher flow rates. Further, differential pressures between inside the liner and the farthest pressure ports are higher than the same with pressure ports closer to the liner.

According to Figure 9, the pressure readings of the ports located the most distant from the liner (A1, A2, and A3) are within 7%, which indicates that the flow is distributed relatively uniformly around the liner (Figure 9a). In the ports close to the liner (B1, B2, and B3), pressure differentials are also within 6%, which supports the uniformity of the flow inside the sand pack (Figure 9b).

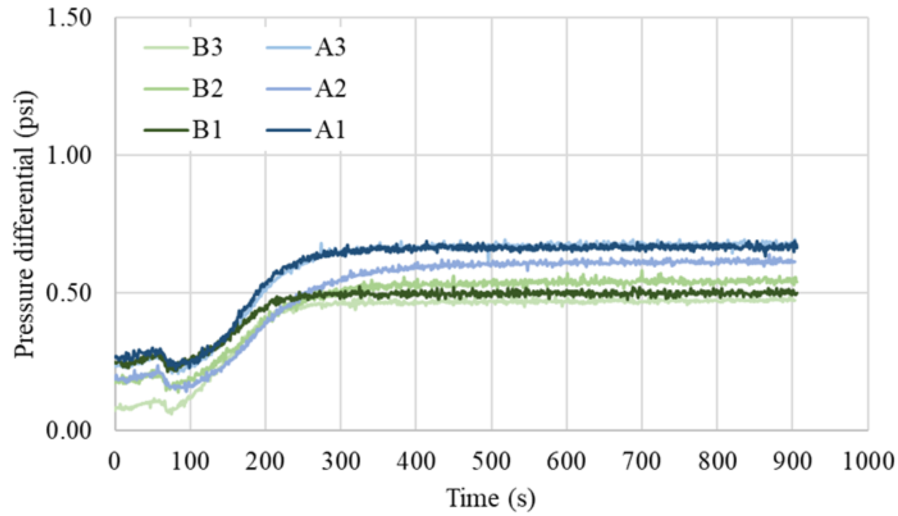

Figure 8. Pressure stabilization at the different pressure ports when injecting brine at 30 lit/hr in Test#2

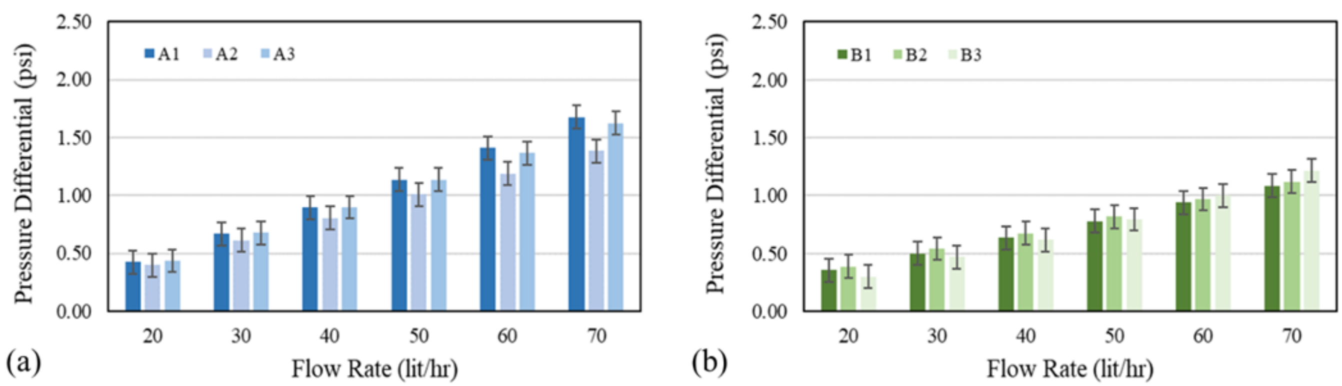

Figure 9. Differential pressure between the ports located a) far from, and b) close to the liner and a port located inside the liner in Test#2

4.1.2. Fines concentration

Fine particles are mobilized due to interaction with the brine and migrated inside the formation by drag forces generated by the flowing fluid. Migrated particles would be produced with the discharged brine or trapped inside the pore spaces/throats around the liner. In a uniform flow condition inside the sand pack, it is expected to observe comparable fines concentration in the samples taken from same radial positions. Therefore, fines concentration inside the sand pack is considered as an indication of the uniformly distributed flow around the liner.

Core samples were extracted after the tests from the sand pack using a split core barrel for PSD measurement (by wet sieving) to measure the concentration of the fines along the sand pack (Figure

10). Eight cores were obtained, including six horizontal and two vertical cores. The horizontal cores were extracted from different levels (3.5, 6.5, and 9.5 inches from the bottom) from the front and backside of the sand pack. Three samples were extracted from each horizontal core located at the intervals with the following distances from the outer surface of the liner: 0-0.8in, 0.8-1.6in, and 1.6-2.4in. The horizontal samples were labeled using four terms including location (F for front and B for backside), level (B, M and T for 3.5, 6.5, and 9.5 inches from the bottom), and radial distance (C for 0-0.8in, M for 0.8-1.6in, and F for 1.6-2.4in from the outer liner surface).

The vertical cores were obtained at the 5- and 1-inch radial distances from the liner. From each vertical core, five 1-inch samples were obtained at 3.5, 6.5, 9.5, 12, and 14 inches from the bottom for post-mortem analysis. The vertical samples were also labeled using sample type (V for vertical samples), location (F for front and B for backside), level (B, M and T, T1, and T2 for vertical distances from the bottom at 3.5, 6.5, 9.5, 12, and 14 inches). The length of each sample taken from vertical cores was 1 inch. For instance, sample 6.5 from bottom inches was taken from 6 to 7 inches. Each sample, either vertical or horizontal, represents the mid-distance of the interval.

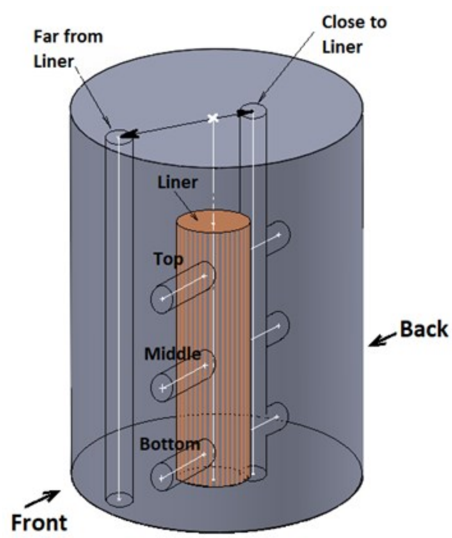

Figure 10. Schematic showing the locations of horizontal and vertical cores taken from the sand pack after the test

Fines concentrations (particles smaller than 44 microns) were measured by the wet sieving method. As expected, fine particles were displaced from the side to the center of the sample during the flow (Figure 11). In the horizontal samples, the samples located at the distance of 1.6-2.4in have lower fines concentration than the sample located at the distance of 0-0.8in. The average value of the concentration of the fines in the far samples is about 12.46%, which increases to 12.66% in the close samples. Although a general trend shows reducing fines concentrations with distance from the liner, the difference is not too significant. The low amount of migrated fines can be attributed to the salinity level of brine in this test (~400 ppm), which was at the level with a low potential to mobilize the fine particles (Haftani et al., 2019). It appears the flow velocity was not high enough far from the liner to detach the particles from grain surfaces and displace them along the entire length of the sand pack. As found in the literature (e.g., Mahmoudi et al., 2017; Haftani et al., 2019), fines migration would be more substantial if brine with lower salinity and higher fluid flow velocity is injected. Moreover, in case of the high possibility of the fines migration, having a liner with narrower aperture size would increase the fines accumulation close to the liner, and thus, resulting in a significant variation between fines concentrations close and far from the liner.

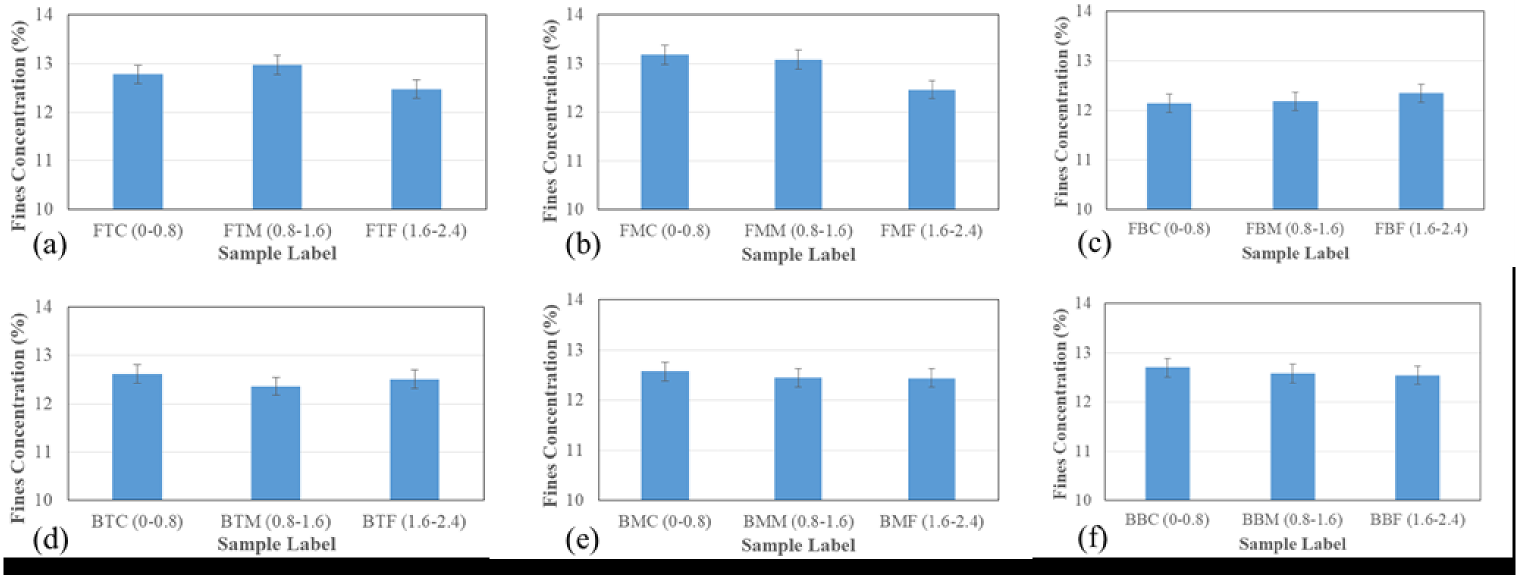

Figure 11. Fines concentration in the horizontal samples in Test#2 from the sand pack at a) Front side-Top, b) Front side-Middle, c) Front side-bottom, d) Backside-Top, e) Backside-Middle, and f) Backside-Bottom

Bar diagrams in Figure 12 show that the fines concentration at the horizontal samples located at the same radial distance, but different elevations (top, middle and bottom) and locations (front and backside) show less than 4% variation, which is reasonably close. Uniform fines concentration at equal radial distances along the sand pack indicates uniform flow distribution inside the sample.

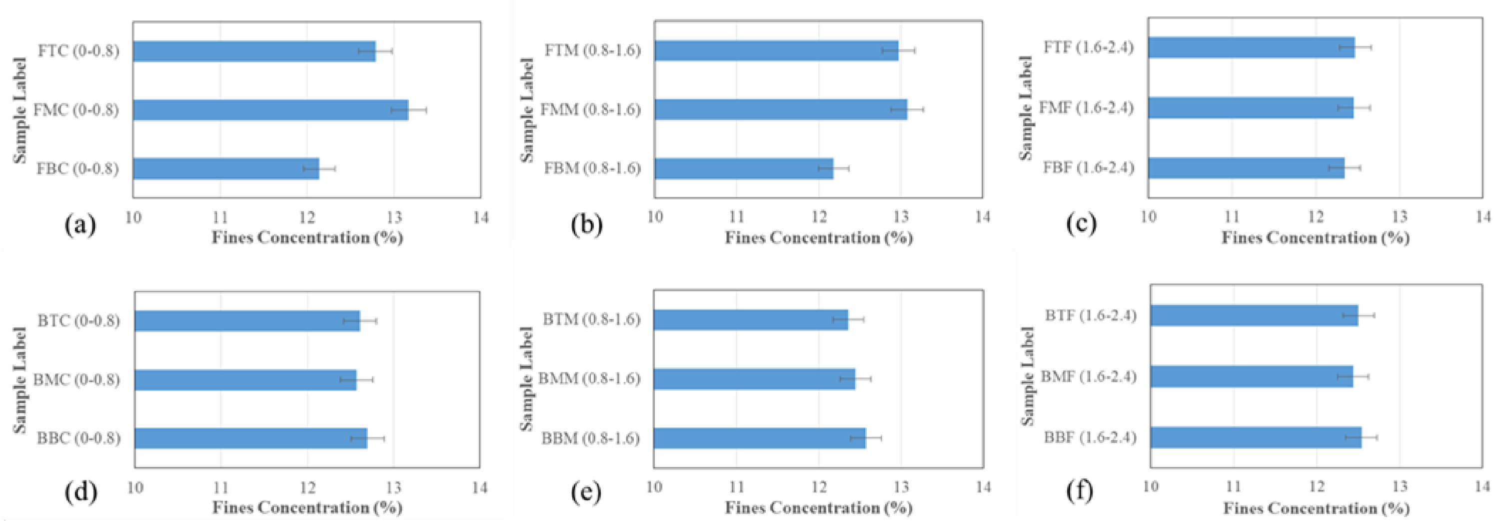

Figure 12. Fines concentration inside the samples located at different distances from the liner, a) Front side-Close to the liner, b) Front side-Middle distance to the liner, c) Front side-Far from the liner, d) Backside-Close to the liner, e) Backside-Middle distance to the liner, and f) Backside-Far from the liner

As the vertical samples are located at the same radial distances, it is expected to see similar fines concentration in the samples provided a uniform radial flow condition. Figure 13 shows that the fines concentrations for the samples taken from the vertical cores are within 4% and 2% for the front and back samples, respectively, which supports the presence of a uniform flow. Besides, the horizontal samples located in the same radial distances show similar fines concentrations that support this statement (e.g., horizontal samples taken from the front side close to the liner and the backside close to the liner, which is shown in Figure 12c and Figure 12f, respectively, etc.).

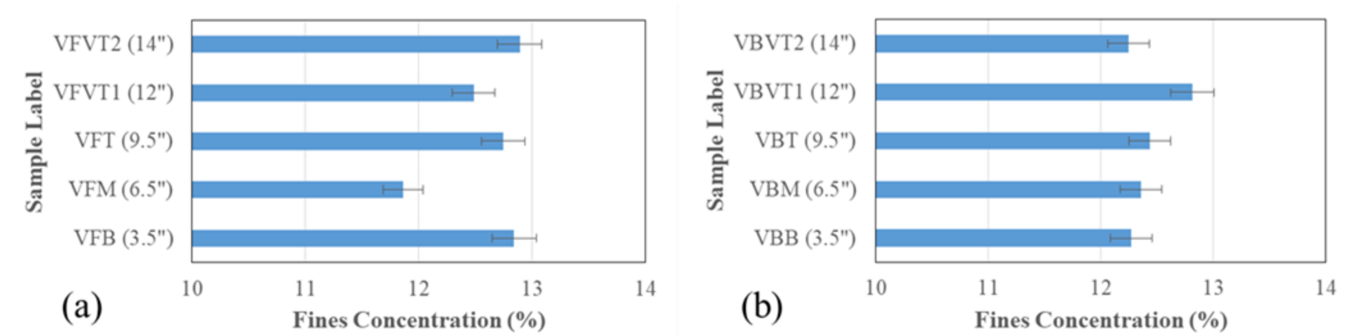

Figure 13. Fines concentration inside the vertical samples, a) Front side-Far from the liner, and b) Backside-Close to the liner

4.2. Test repeatability

This section presents the results of a second test, which was performed following the same procedure as the first one to examine the reproducibility of the test results.

4.2.1. Differential pressure measurement

Figure 14 compares the differential pressures measured around the liner in the tests to show the repeatability of the test results. It can be seen from the figure that differential pressures from the two tests show similar variations with the flow rate, and their differences are less than 5%.

4.2.2. Permeability of the sand pack

The permeability of the sand pack at each interval was calculated by the following equation (Ahmed, 2010):

$$Q_w = \frac{0.00708\ k\ h\ (p_e - p_w)}{\mu_w\ ln(r_e/r_w)}$$

where Q_w is the flow rate (STB/day), p_e is external pressure (psi), p_w is hole pressure (psi), k is permeability (md), μ_w is viscosity (cp), h is the thickness (ft), r_e is external or drainage radius (ft), and r_w is wellbore radius (ft).

Figure 15 shows lower permeability for higher flow rates, which is attributed to the permeability reduction due to the fines migration and pore plugging. It is also noticeable that both tests show comparable permeability values for different intervals. The error bars presented in Figures 14 and 15 were calculated based on the maximum errors by the transducers.

The plugging by fines accumulation around the liner has been assessed through a parameter called retained permeability (Mahmoudi et al., 2017). This parameter is calculated as the ratio of the permeability in the vicinity of the coupon over the initial permeability at the beginning of the test.

The average retained permeability of the sand pack in the FCT experiments herein is about 86%. Wang et al. (2020b) showed that retained permeability values of about 65%, 74%, and 80% for the single-phase SRT experiments for the DC-I PSD using seemed coupons with the slot size of 0.022-0.030 inches and slot densities of 30, 42 and 52 slots per column, respectively. Comparing the retained permeability reported in the literature for SRT experiments with the same in FCT experiments displays a lower retained permeability in SRT experiments.

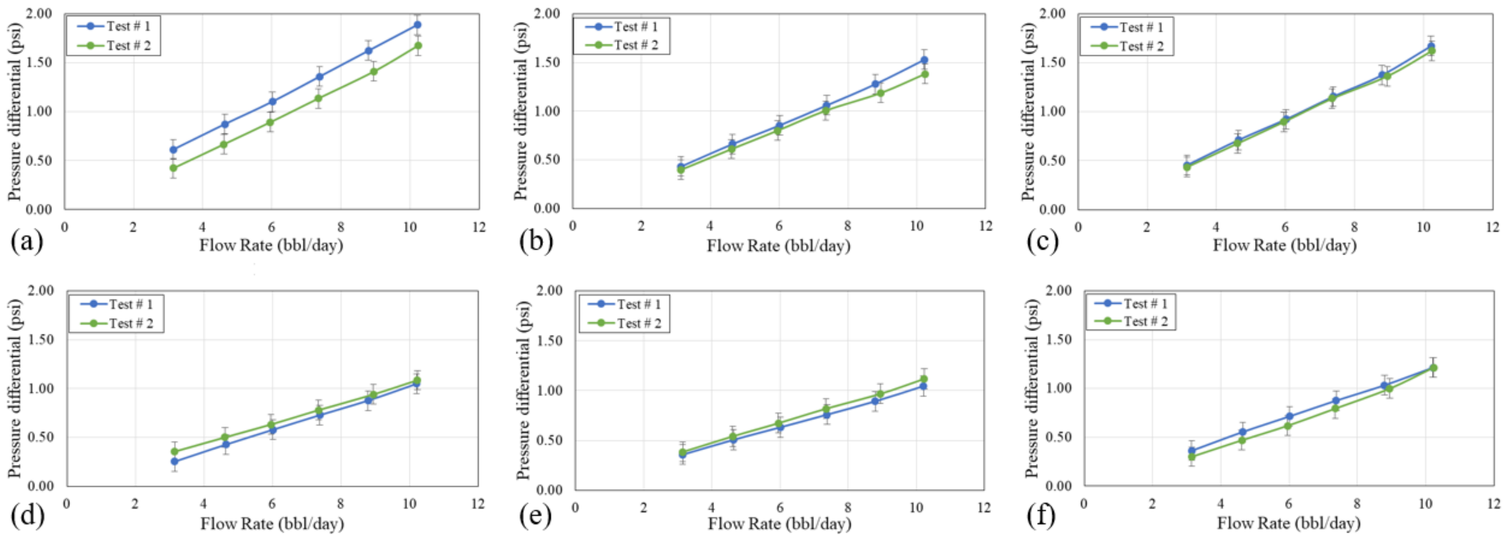

Figure 14. Comparing the differential pressures recorded in Tests #1 and #2 at different measurement locations; a) A1, b) A2, c) A3, d) B1, e) B2, and f) B3

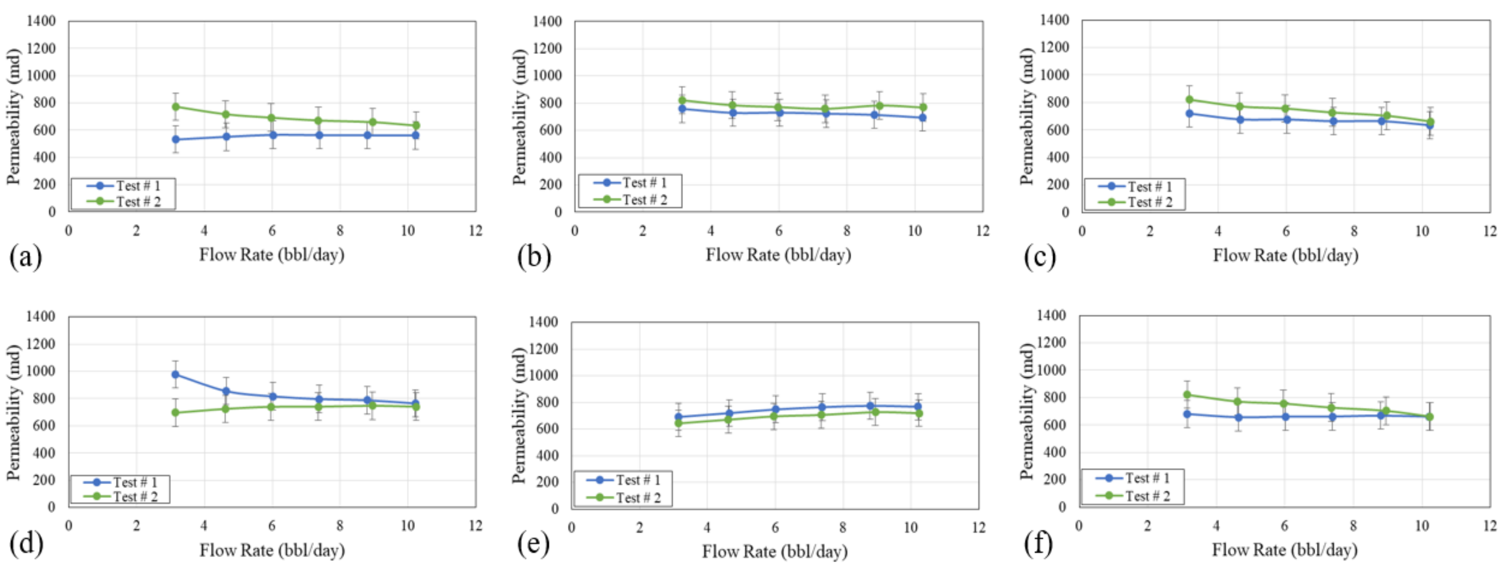

Figure 15. Comparing the permeability values calculated for Tests #1 and #2 at different locations; a) A1, b) A2, c) A3, d) B1, e) B2, and f) B3

4.2.3. Produced sand

After each test, the produced sands were meticulously collected from 1) the sand trap, and 2) inside the slots. The total produced sands in Tests #1 and 2 are 8.8 and 6.6 grams, respectively. As the area of the liner is about 1 ft^2, the produced sands are 0.02 and 0.015 lb/ft^2, which are within acceptable sanding levels (less than 0.12 lb/ft^2) for SAGD as suggested by Hodge et al. (2002).

A review of the literature on the amount of produced sand in the current testing approaches (such as SRT) may indicate more sand production in SRT compared to the FCT eperiment. Wang et al. (2020b) showed that the cumulative produced sand in single-phase SRT experiments on DC-I using a seamed coupon with a slot size of 0.022-0.030 inches and different slot densities is more than 0.20 lb/ft^2. This rate of sanding exceeds the acceptable sanding level (0.12 lb/ft^2). In contrast, in the FCT experiments, total produced sand particles are 8.8 and 6.6 grams, which are about 0.02 and 0.015 lb/ft^2. Low produced sand in FCT can be partly attributed to the liner corrosion during the test, resulting in slot plugging by solid particles. Also, the gravity force on sand particles close to the liner in these tests helps the particles stay in their places.

4.2.4. Fines concentration in produced brine

Discharged brine samples were collected from the top part of the sand trap at each flow rate. A Turbidimeter was employed to measure the turbidity of the produced brine. Then, the solids concentration in the brine was calculated from the values measured by the turbidimeter.

Figure 16 illustrates the cumulative fines concentration versus flow rate for both Tests #1 and 2. The figure shows reasonably close fines production for both tests. In contrast with the literature on SRT experiments with an exponential trend for fines production versus flow rate (see Mahmoudi et al., 2017), a nearly linear trend is observed in FCT. This dissimilarity can be attributed to the salinity level of the flowing brine and fluid flow velocity along the sand pack. Fines mobilization might be insignificant in the sand pack at the salinity level of 400ppm (Haftani et al., 2019). Furthermore, the same fluid flow velocity from top to bottom of the sand pack in the SRT experiments would mobilize and migrate the fine particles from the top part of the sand pack. Instead, in FCT experiments, the fluid flow velocity is not constant at different radial distances due to the variable open to the flow area moving farther from the liner. Fines migration would occur inside the sand pack only where the flow velocity is higher than the critical flow velocity.

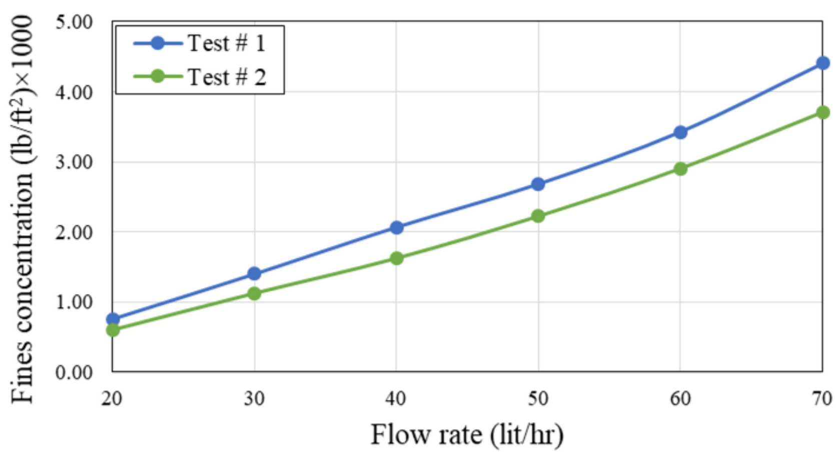

Figure 16. Cumulative produced fines concentration in the discharge water

5. Conclusions

This paper introduces a new testing facility for the evaluation of the liner performance in the SAGD wells, called Full-scale Completion Test (FCT) facility. The FCT apparatus uses the cylindrical liner instead of a coupon that is used in Sand Retention Testing. This experimental setup is developed to evaluate the sanding and flow performance of the liner at the presence of the radial flow regime, which is more representative of SAGD wells.

After manufacturing the testing equipment, several single-phase experimental tests with brine flow were performed to troubleshoot challenges and shortcomings in setup and testing procedure. Two single-phase pre-pack FCT were carried out to show that the flow rate is uniform around the liner, and the test results are repeatable.

In each test, differential pressure readings at the ports located at similar radial distances show similar values, which means that the flow is uniformly distributed. Fines concentration in the samples, as measured after the testing, also supports the existence of the uniform flow inside the sand pack.

Comparing the two FCT test results shows that differential pressures and permeability measurements follow similar trends. The measured values show some differences, but they are in reasonable agreement. Produced fines concentration in the produced water for different tests shows reasonable agreement as well. Therefore, it is concluded that test results are repeatable, and this facility and testing procedure allows confidently evaluate the sand control screen performance.

The FCT is quite new and needs further investigations to broaden its application, as it is ongoing by the authors. Therefore, it is proposed to compare the test results obtained from SRT and FCT, and the FCT results once running the test in vertical and horizontal directions. As this equipment is capable of flowing multi-phase oil-water-gas, conducting multi-phase FCT tests and developing the design criteria for aperture sizing of SCD in more representative testing conditions is in the future research plans.

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