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Shear-enhanced permeability and poroelastic deformation in
unconsolidated sands

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Shear-enhanced permeability and poroelastic deformation in unconsolidated sands

by

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Dedication

To my dear parents and siblings for their endless love and support
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I would like to thank all my friends for their wonderful and pleasant company. They helped to make this journey a very memorable one.
Abstract

Shear-enhanced permeability and poroelastic deformation in unconsolidated sands

Syed Muhammad Farrukh Hamza, M.S.E
The University of Texas at Austin, 2012

Supervisor: Jon E. Olson

Heavy oil production depends on the understanding of mechanical and flow properties of unconsolidated or weakly consolidated sands under different loading paths and boundary conditions. Reconstituted bitumen-free Athabasca oil-sands samples were used to investigate the geomechanics of a steam injection process such as the Steam Assisted Gravity Drainage (SAGD). Four stress paths have been studied in this work: triaxial compression, radial extension, pore pressure increase and isotropic compression. Absolute permeability, end-point relative permeability to oil & water \(k_{ro}\) and \(k_{rw}\), initial water saturation and residual oil saturation were measured while the samples deformed.

Triaxial compression is a stress path of increasing mean stress while radial extension and pore pressure increase lead to decreasing mean stress. Pore pressure increase experiments were carried out for three initial states: equal axial and confining stresses, axial stress greater than confining stress and confining stress greater than axial stress. Pore pressure was increased under four boundary conditions: 1) constant axial and confining stress; 2) constant axial stress and zero radial strain; 3) zero axial strain and...
constant confining stress; and 4) zero axial and radial strain. These experiments were designed to mimic geologic conditions where vertical stress was either $S_1$ or $S_3$, the lateral boundary conditions were either zero strain or constant stress, and the vertical boundary conditions were either zero strain or constant stress.

Triaxial compression caused a decrease in permeability as the sample compacted, followed by appreciable permeability enhancement during sample dilation. Radial extension led to sample dilation, shear failure and permeability increase from the beginning. The $k_{rw}$ and $k_{ro}$ increased by 40% and 15% post-compaction respectively for the samples corresponding to lower depths during triaxial compression. For these samples, residual oil saturation decreased by as much as 40%. For radial extension, the permeability enhancement decreased with depth and ranged from 20% to 50% while the residual oil saturation decreased by up to 55%. For both stress paths, more shear-enhanced permeability was observed for samples tested at lower pressures, implying that permeability enhancement is higher for shallower sands. The pore pressure increase experiments showed an increase of only 0-10% in absolute permeability except when the effective stress became close to zero. This could possibly have occurred due to steady state flow not being reached during absolute permeability measurement. The $k_{rw}$ curves generally increased as the pore pressure was increased from 0 psi. The increase ranged from 5% to 44% for the different boundary conditions and differential stresses. The $k_{ro}$ curves also showed an increasing trend for most of the cases. The residual oil saturation decreased by 40-60% for samples corresponding to shallow depths while it increased by 0-10% for samples corresponding to greater depths. The reservoirs with high differential stress are more conducive to favorable changes in permeability and residual oil saturation. These results suggested that a decreasing mean stress path is more beneficial for production increase than an increasing mean stress path. The unconsolidated sands are
over-consolidated because of previous ice loading which makes the sand matrix stiffer. In this work, it was found that over-consolidation, as expected, decreased the porosity and permeability (40-50%) and increased the Young’s and bulk moduli of the sand. The result is sand which failed at higher than expected stress during triaxial compression.

Overall, results show that lab experiments support increased permeability due to steam injection operations in heavy oil, and more importantly, the observed reduction in residual oil saturation implies SAGD induced deformation should improve recovery factors.
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Chapter 1

Introduction

About 70% of the oil in the world is categorized as having less than 20°API gravity and present in unconsolidated sandstone reservoirs less than 1000 m deep (Dusseault, 2001), that is, the majority of world oil reserves consist of heavy oil, extra-heavy oil and bitumen (Fig. 1.1). Heavy oil, extra-heavy oil and bitumen are unconventional oil resources which are characterized by high viscosities and high densities. Heavy oil deposits are defined as the petroleum resources which are between 10 and 20°API gravity, while extra heavy oil deposits are those which are less than 10°API gravity. Natural Bitumen is reported in 598 deposits in 23 countries, which amounts to 3.3 trillion barrels of total original oil in place (World Energy Council, 2010). These deposits occur both in clastic and carbonate rocks and commonly close to the earth’s surface. Extra-heavy oil is found in 162 deposits in 21 countries, and amounts to 3.1 trillion barrels of total original oil in place (World Energy Council, 2010).

Figure 1.1: Total world oil reserves (modified from Schlumberger Oilfield review, 2006).
Canada’s recoverable oil sands resources (28 trillion m$^3$ or 177 billion barrels) are roughly comparable to Saudi Arabia’s proven oil reserves (Table 1.1). After Canada, the largest bitumen volumes are found in Kazakhstan and Russia. Majority of the Kazakh deposits are found in the North Caspian Basin, while many of Russia’s bitumen deposits are located in the Timan-Pechhora and Volga-Ural basins (World Energy Council, 2010). These deposits are geologically similar to the Western Canada bitumen deposits (Meyer et al., 2006). Venezuela’s Orinoco Belt contains extra-heavy crude oil in comparable numbers to Canada’s bitumen deposits.

<table>
<thead>
<tr>
<th>Country</th>
<th>In Place Bitumen</th>
<th>Recoverable Bitumen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Canada</td>
<td>259.2</td>
<td>28.3</td>
</tr>
<tr>
<td>Former Soviet Union</td>
<td>30.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Nigeria$^1$</td>
<td>6.8</td>
<td>0.2</td>
</tr>
<tr>
<td>United States$^2$</td>
<td>4.4</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td>Venezuela$^3$</td>
<td>8</td>
<td>n/a</td>
</tr>
</tbody>
</table>

1 Only includes volumes from Ondo and Ogun States, with mineable portion only as recoverable
2 Estimate only, small mining volumes for road material are considered recoverable at this time.
3 Does not include heavy or extra heavy crude oil. Source U.S. Geological Survey

Table 1.1: World bitumen resources ($10^9$ m$^3$) (Canada’s National Energy Board, 2000).

The Government of Alberta's Energy Resources Conservation Board (ERCB) estimated in 2010 that there are 1804 billion barrels of crude bitumen in Alberta’s three oil sands areas, out of which about 177 billion barrels ($27.5 \times 10^9$ m$^3$) are economically recoverable. Since the start of commercial production in 1967, only about 4% of the initial established crude bitumen reserves have been produced. Bitumen production is set to double by 2020 in Alberta (Fig. 1.2).
1.1 WHY HEAVY OIL & BITUMEN

World oil demand grew by 3.4% in 2010 and by 1.6% in 2011 (IEA, 2011) and is set to grow even further. Production from heavy, extra-heavy and oil sands resources will serve to meet the growing liquids energy needs (Fig. 1.3). The development of Canadian and Venezuelan heavy oil deposits has accelerated in recent years, mainly due to consistent high demand which is pushing oil prices high enough to encourage investment. In Canada, the production of bitumen using Steam Assisted Gravity Drainage (SAGD) is rapidly growing. In Venezuela, cold production using horizontal and multilateral wells is the most popular method (Clark et al., 2007). Other reasons for the increase in heavy oil and oil sands development include

- a sharp decrease in operating costs due to development and adoption of new technology,
• the development of Steam Assisted Gravity Drainage (SAGD) method for bitumen production,
• improvement in horizontal well technology,
• declining domestic conventional crude oil production levels in North America, coupled with increasing demand, and
• optimism regarding future oil prices.

Figure 1.3: Present and future global energy demand (from U.S. EIA, 2011).

1.2 CANADIAN OIL SANDS

Canada's oil sands are located in three deposits - the Athabasca, Peace River and Cold Lake deposits (Figures 1.4 and 1.5). Near Fort McMurray, the oil sands are near the surface where they can be easily mined. The overburden thickness ranges from 0 to 750 meters; only about 10% of the oil sands are close enough to the surface to be mined (Touhidi-Baghini, 1998). SAGD (Steam Assisted Gravity Drainage) and Cyclic Steam Stimulation are the two most popular drilling (in situ) methods for oil production from
these oil sands reserves. The Athabasca oil sands deposits are located in Northern Alberta and span an area of 40,000 square kilometers. These deposits contain 140 billion cubic meters or one trillion barrels of original bitumen-in-place (Deutsch and McLennan, 2005).

Dusseault (1977) defined Athabasca Oil Sands as “the oil-bearing portions of two geological formations (Carrigy, 1959): the McMurray Formation, which contains well over 95% of the oil reserves; and the Clearwater Formation.” The McMurray Formation is Lower Cretaceous in age (Russel, 1932; Mellon and Wall, 1956). Over 2500 meters of ice covered the area during glaciation (Dusseault, 1977).
1.3 **Athabasca Oil Sands Properties**

The oil sands deposits contain quartz sand, silt, clay, water and bitumen. The bitumen has a density of 970 to 1015 kg/m$^3$ (8 to 14° API) and a viscosity greater than 50,000 cP (centipoise) at room temperature. Athabasca oil sands are relatively shallow resources as compared to the conventional oil resources. Dusseault (1977a) reported the overburden to be from 0 to 600 meters for Athabasca, and from 100 to 750 meters for other bitumen resources in Alberta, Canada. Oil sands are loose sands, held together by
bitumen. However, bitumen does not act as a cementing agent since it is a Newtonian fluid and hence provides no shear resistance at a zero shear rate (Bowman, 1967). As a consequence, it cannot contribute to the static mechanical strength of the material, provided the deformation does not proceed very rapidly (Dusseault, 1977b). Most of the oil-rich sands are fine to medium grained with some silt and clay sized material (Dusseault, 1977a). The quartz grains are water-wet (Bowman, 1967). The bitumen has a specific gravity slightly higher than 1, and in situ viscosity ranges from 6000 to several million poises (Ward and Clark, 1950). The porosity of the Athabasca oil sands has been reported in numerous works with different ranges, such as: 33 to 35.5% (Blair, 1950), 34 to 46% (Clark, 1957), 38 to 42% (Doscher et al., 1963), 40% at 60 m depth & 34% at 300 m depth (Carrigy, 1967), 32.5 to 35% (Oldakowski, 1994). A number of permeability values have also been reported, such as: up to 5000 md (Carrigy and Kramers, 1974), up to 650 md (Clark, 1959), 0.5 to 5 Darcy (Dusseault, 2001).

1.4 Production technologies

Heavy oil and bitumen resources can be developed using a number of methods. A brief summary is given in table 1.2. The main issue with these reservoirs is the very high viscosity. Thermal recovery methods such as steam injection solve this problem by decreasing the viscosity and increasing the mobility. Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) are the two fairly recent and popular methods to produce from these heavy oil and bitumen reservoirs.
Some of the production methods in the pilot phase are tabulated in Table 1.3. If successful, they seek to lower the energy consumption, decrease the environmental cost, increase the production rates and be more economical.

<table>
<thead>
<tr>
<th>Method</th>
<th>Description</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open-pit mining</td>
<td>Used in Canada for shallow oil sands</td>
<td>High recovery factor, but high environmental impact</td>
</tr>
<tr>
<td>Cold production using horizontal</td>
<td>Used in Venezuela, some use in North Sea</td>
<td>Low recovery factor, may use water drive (North Sea)</td>
</tr>
<tr>
<td>wells and multilateral wells</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cold heavy oil production with sand</td>
<td>Used in Western Canada to exploit thin layers</td>
<td>Low recovery factor, needs good gas/oil ratio (GOR), unconsolidated sands</td>
</tr>
<tr>
<td>(CHOPS)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cyclic steam stimulation (CSS)</td>
<td>Used in USA, Canada, Indonesia, many others</td>
<td>Reduce viscosity of heavy oil, needs good caprock, fair-to-good recovery factor</td>
</tr>
<tr>
<td>Steamflood</td>
<td>Used in USA, Canada, Indonesia, many others</td>
<td>Follow-up to CSS for interwell oil, good-to-high recovery factor</td>
</tr>
<tr>
<td>Steam assisted gravity drainage</td>
<td>Used in Canada</td>
<td>Allows production from shallower sands with weaker caprock</td>
</tr>
<tr>
<td>(SAGD)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 1.3: Major production methods in pilot phase (from Clark et al., 2007).
1.5 **Steam Assisted Gravity Drainage (SAGD)**

Steam Assisted Gravity Drainage (SAGD) is an in-situ thermal heavy oil recovery method, first proposed and developed by Roger Butler in the late 1970s ((Butler, 1994; Al-Bahlani et al., 2009). As shown in Fig. 1.6, SAGD production method involves drilling two wells, both with horizontal sections, drilled with one well directly above the other well. The wells are completed with slotted liners to reduce sand production. The two wells are separated by typically 5 meters. The horizontal sections are usually 500 to 1500 m long (Clark et al., 2007). Although a number of studies have been conducted to determine the ideal inter-well spacing or length (Singhal et al., 1998; Sasaki et al., 2001; Terez, 2002), there is no agreement on the optimum inter-well spacing or length. The common practice for inter-well spacing is to place the wells 5-15 m apart.

![Figure 1.6: Injector and producer wells and their relative placement for SAGD process shown in an isometric view. Red arrows show steam injection from the top well into the reservoir, while white arrows show the bitumen flow into the bottom well. The gray region is the steam chamber. (http://www.japex.co.jp/english/business/oversea/sadg.html)](http://www.japex.co.jp/english/business/oversea/sadg.html)

In the startup phase, steam is injected through both the wells to decrease the viscosity of bitumen between the well-pair. After steam has filled the pore-space between
the two wells and caused bitumen to flow, only the top well is used for steam injection. Because of the lower density of steam, it rises up and expands out to form a conical shaped steam chamber. The steam chamber follows the path of higher conductivity and the shape may not be conical. Ideally, this steam chamber is formed above the injection well and does not break through to the lower production well. As the steam expands, it comes in contact with more bitumen saturated sands, causing heat transfer. Convection is the predominant heat transfer mode, followed by conduction (Farooq-Ali, 1997). As the new bitumen is heated, the oil lowers in viscosity and flows downward, being assisted by gravity. Therefore, SAGD is a counter-current gravity drainage process. The steam is always injected below the fracture pressure of the reservoir at a high enough temperature to offset the heat losses in the well-bore. Other engineering factors to consider are thermal efficiency, steam pressure & quality, steam injection rate, reservoir pressure maintenance, water intrusion, and well-spacing (Deutsch et al., 2005).

1.5.1 Advantages of SAGD

Table 1.4 shows the bitumen resources in Canada available for in situ production methods. The development of SAGD method has a number of advantages compared to other steam stimulation methods that make it favorable to be used in a wide range of bitumen reservoirs. With the ability to drill low-cost horizontal wells and the very high recovery factor of the SAGD process (up to 60% of the oil in place), SAGD is the most attractive option for bitumen production. The SAGD process enables greater well production rates, greater reservoir recoveries, reduced water treatment costs and lower steam-oil ratios (Deutsch et al., 2005). Cunha (2005) reports recovery factors of 5-15% for cold production, 20-25% for Cyclic Steam Stimulation and 40-50% for SAGD. In contrast to mining, the environmental footprint of SAGD process is much smaller and deeper resources can also be produced. Since the SAGD injection well operates at a
lower steam pressure than CSS or steam-flood well, less overburden is required for steam containment.

<table>
<thead>
<tr>
<th>Mineable</th>
<th>Ultimate Volume in Place</th>
<th>Initial Volume in Place</th>
<th>Ultimate Recoverable Volume</th>
<th>Initial Established Reserves</th>
<th>Cumulative Production</th>
<th>Remaining Reserves</th>
</tr>
</thead>
<tbody>
<tr>
<td>Athabasca</td>
<td>24</td>
<td>18</td>
<td>10</td>
<td>5.6</td>
<td>0.4</td>
<td>5.2</td>
</tr>
<tr>
<td>In Situ</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Athabasca</td>
<td>n/a</td>
<td>188.7</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Cold Lake</td>
<td>n/a</td>
<td>31.9</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Peace River</td>
<td>n/a</td>
<td>20.5</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Subtotal</td>
<td>376</td>
<td>241.2</td>
<td>39</td>
<td>22.7</td>
<td>0.1</td>
<td>22.6</td>
</tr>
<tr>
<td>Total</td>
<td>400</td>
<td>259.2</td>
<td>49</td>
<td>28.3</td>
<td>0.5</td>
<td>27.8</td>
</tr>
</tbody>
</table>

Table 1.4: Crude bitumen resource ($10^9$ m$^3$) in Canada (from Canada’s National Energy Board, 2000).

1.5.2 Application of SAGD

Based on the depth of the target formation, SAGD recovery method can be applied to reservoirs which are 100 to 300 m deep if the horizontal and vertical permeabilities are good and net pay thickness is greater than 10 m. SAGD can also be applied to intermediate depths of 300 to 1000 m. However, deeper reservoir depths require higher temperature steam and are therefore less economic. For depths greater than 1000 m, SAGD cannot be applied because excessive heat losses are encountered due to the overburden. For shallow reservoirs with 100 m or less depth, SAGD is usually not used. In addition, SAGD method cannot be economically applied to thin beds (less than 10 m) or for highly laminated beds.
1.5.3 Geomechanics of SAGD

During SAGD, steam is injected into the Athabasca oil sands reservoir at high temperature and pressure. The changes in pressure and temperature cause changes in stress and deformations which result in formation shearing and permeability changes. The deformation response of Athabasca oil sands is stress path dependent (Agar, 1984; Dusseault, 1977; Kosar, 1989; Oldakowski, 1994; Plewes, 1987). A temperature increase causes thermal expansion of the sand grains (Scott et al., 1994). A pore pressure increase causes effective stresses to decrease (Terzaghi, 1943) since the part of the total stresses would be carried by the pore fluid. Both of these stress paths are shown in Fig. 1.7.

The thermal expansion of the reservoir due to the injected steam causes thermal stresses in the horizontal direction, since the reservoir is bounded laterally by the surrounding rock formations. This causes horizontal total stresses to increase. The vertical stress due to the overburden remains constant because at shallow depths the earth surface is a free surface. In the SAGD operations in the Athabasca oil sands, the temperature increase is normally about 250°C, which can result in thermal stress as high as 6 MPa (870 psi) (Li and Chalaturnyk, 2006). The increasing horizontal stresses and the constant vertical stress results in an increasing mean stress as well as an increasing differential stress. This stress path can be tested in the laboratory using a triaxial compression stress path, which fulfills these two conditions on mean and differential stresses. The vertical stress is the minimum stress in the Athabasca oil sands as it is a thrust faulting stress environment (Zoback at al., 1989).

The pore pressure increase in the reservoir due to the steam injection reduces the effective vertical and horizontal stresses. This represents a path of decreasing mean stress. This stress path can be studied either by conducting radial extension experiments or by increasing the pore pressure itself. Both these stress paths would result in decreasing mean stress. Brooker (1975) suggested that the horizontal stress exceeds the vertical stress by a factor of about 3 from the surface to at least 330 m depth. This stress
state causes hydraulically induced fractures to propagate horizontally (Doscher et al., 1963). In the McMurray Formation, the ratio of the maximum effective horizontal stress to the vertical effective stress is about 1.5 (Harris and Graham, 1989). For an anisotropic in situ stress state, pore pressure increase would generate shear stresses and shear strains causing reservoir pore volume and permeability to change (Scott et al., 1994). The evolution of zones of shear induced volume and permeability changes is sensitive to the initial stress state and the steam injection pressure (Chalaturnyk and Li, 2004).
1.5.4 Stress-Induced Permeability Variations

Reconstituted Athabasca samples have been used by Dusseault (1977), Agar (1984), Oldakowski (1994) and Touhidi-Baghini (1998). Touhidi-Baghini (1998) also used cored Bitumen-free Athabasca samples. The initial porosity in Tohidi-Baghini’s
(1998) samples ranged from 33 to 35 percent, and the initial permeability for both horizontal and vertical samples was between 1.5 and 4 Darcy. These experiments were performed at low initial effective stress of 36 psi and the maximum differential stress was 160 psi. The permeability increase was between 30 and 50 percent for triaxial compression and 50-70% for radial extension. Oldakowski (1994) performed triaxial compression, isotropic unloading and anisotropic unloading. He concluded that the absolute permeability change is a function of the pore volume changes, which is a function of the stress path followed. Also, the absolute permeability measured on reconstituted oil-free oil sands samples and on extracted sand cores are within the same range when the porosities are similar. Dilation was more pronounced in the close to peak and post-peak stress ranges. For triaxial compression experiments, the average volume increase was 3% at 12% axial strain, with a 42% increase in absolute permeability. Isotropic unloading from 4 MPa (580 psi) to 0.2 MPa (29 psi) effective confining stress, resulted in a 1.4% increase in specimen volume, with permeability increase of 13% to 70%. Scott et al. (1994) performed isotropic unloading on Cold Lake oil sand cores, by decreasing the effective stress from 12 MPa (1740 psi) to 0 MPa. They observed a 15% increase in effective permeability to water. The triaxial compression experiments were conducted at 1 MPa (145 psi) and 7 MPa (1015 psi) effective confining stress. The 1 MPa sample compacted initially and then dilated; the permeability decreased by 6% during compaction and increased by 10% during dilation. The 7 MPa sample did not dilate, resulting in a 32% decrease in permeability at the same axial strain of 8.5% as the 1 MPa sample.

These studies did not involve experiments performed on Athabasca oil sands samples, using two-phase oil-water flow and did not report initial water and residual oil saturations during the different stress paths followed during the SAGD operation, such as triaxial compression, radial extension and pore pressure increase.
1.5.5 Effect of Over-consolidation

The Athabasca oil sands have been subjected to continental glaciation, which increased the overburden stresses significantly. The maximum total thickness of the ice was around 1800 m, and this thickness would result in a total stress increase of about 2300 psi (Dusseault, 1977). When the overburden is removed or eroded, the vertical stress is relieved but the horizontal stresses are not relieved due to lateral constraints. The vertical stress can be reduced until the horizontal stresses become greater. The limit to the maximum horizontal stresses is reached when the differential stresses start to cause shear failure. Adopting a principal stress ratio (the ratio of the effective maximum principal stress to the effective minimum principal stress) of 3.5, Dusseault (1977) showed that the point of failure for a material buried to a depth of 1000 m would not be reached until the material reached a depth of 80 m. The effect of hydrostatic loading on permeability was investigated by Holt (1990) in which he concluded that there is a significant decrease in permeability with increasing stress, for high porosity (25%) weak sandstone. The permeability decreased from 150 md to 110 md for hydrostatic stress increase from 0 to 5800 psi. Similar work had previously been done by Zoback et al. (1976), Dey (1986) and Gobran et al. (1987) using Ottawa sand, in which they observed a reduction in permeability during increased stress, due to rearrangement of grains into a tighter matrix. The permeability does not return to its original value even when the stress state is restored (Scott et al., 1994). Al-Harthly (1998) listed uneven distribution of stress, failure of internal texture, fines migration, rearranging of pore structure, mobilization of fine grains and an increase of tortuosity due to the collapse of pore space as some of the reasons for permanent reduction in permeability.

1.6 Research Objective

The aim of this work was to study the deformation and associated flow properties of the Athabasca oil sands, especially the relative permeability to oil and water during
stress paths representative of the SAGD process. The relative permeability to oil and water, and the initial water and residual oil saturations have not been studied in detail. An experimental study was carried out to study the effects of different stress paths on reconstituted bitumen-free Athabasca oil-sand samples. The study of deformation and flow properties were carried out for different geologic boundary conditions during pore pressure increase. The effect of initial differential stress conditions was also studied during pore pressure increase experiments. The effect of dilatancy on the absolute and relative permeability, and the oil and water saturations was also analyzed.

An experimental study of deformation and flow properties of unconsolidated sand samples such as Athabasca may lead to better simulation models for coupling geomechanics and fluid flow in unconsolidated heavy, extra-heavy and bitumen reservoirs. Models delineating permeability change due to the stress path followed during the production process would lead to a better understanding of reservoir drainage. Development of more realistic models would lead to improved recovery from heavy oil reservoirs.

In order to obtain better predictions of bitumen production rates, the effect of the SAGD stress paths on the permeability changes in the oil sands reservoir must be understood. This work involved study of the changes in absolute permeability, end point relative permeability, initial water saturation, and residual oil saturation of Athabasca oil sand samples during different stress paths such as triaxial compression, radial extension, pore pressure increase and isotropic compression stress paths.
Chapter 2

Experimental Setup

A laboratory apparatus was designed and assembled to provide measurements of sample deformation and fluid flow. The equipment needed for these measurements is described in the following section. Details of the sample preparation and experimental procedure are also discussed.

2.1 Lab Equipment

An aluminum triaxial cell shown schematically in Fig. 2.1 was used to house a 1.5 inch diameter sand pack during the experiment. The cell consists of a base, an outer cylinder, upper and lower cylindrical rams (loading pistons), a top-plate, six threaded rods, and an axial-load maintaining plate. The bottom ram fits into a circular hole in the base, while the top ram fits into a circular hole in the top-plate. This assembly was held tightly in place by 6 threaded rods which had nuts on the base, and a top-plate and axial-load maintaining plate. The axial-load maintaining plate sat on top of the upper ram, and an additional set of 6 nuts were tightened to keep the axial load in place.

The top and bottom rams (axial loading pistons) contain 1/8” through-going conduits for pore fluid flow. The ends of these rams contained mesh screens on them. The openings in the screens were small enough to stop the fines migration into the flow lines and big enough to prevent a large pressure drop. Transducers attached to the triaxial cell provided for the application and recording of axial stress, confining pressure and pore pressure. Axial and volumetric strains were also measured and recorded.
The triaxial cell was placed in a stiff load frame manufactured by Humboldt Mfg. Co. (model HM-3000), capable of applying up to 10,000 lbs of axial load. The applied load was measured using a S-beam load cell mounted on the load frame. A Linear Variable Differential Transformer (LVDT) was used to measure the linear compression or extension that took place in the sample, during an experiment. The LVDT was mounted on the load frame using a bracket, which provided for up to 2 inches of deformation to be measured and recorded. A data acquisition system transmitted all the transducer outputs to a computer using a RS-232 port and a National Instruments analog...
I/O interface, where it was displayed and recorded using National Instruments' LabView software. The LabView user interface was also used to switch from displacement control to load control for the load frame. The LabView user interface also provided for maintaining isotropic stress on the samples, by controlling the load-frame and confining pressure pump simultaneously. The samples were sieved before and after testing to determine overall grain size distribution and to determine if the stress path caused any fines to be generated.

Two Teledyne Isco model 500D syringe pumps were used to provide confining and pore pressures, ranging from 0 to 3750 psi. The pumps are capable of flowing at rates between 0 and 204 ml/min, with a minimum flow rate of 0.001 milliliter/minute. Two oil-water separators were employed in this experimental setup. One was made of glass and provided a closed-loop solution to filling the second separator with oil, and also enabled a visual inspection of the oil-water level in the separator. However, this separator could only accommodate a maximum of 50 psi. The second separator, made of steel, was used to flow oil into the triaxial cell and was capable of withstanding up to 4000 psi of pressure.

Two burettes were used to collect and measure the effluent from the sand pack. The burettes have ranges of 50 ml and 100 ml, with a resolution of 0.2 ml. This provided a readily visible way to measure the quantity and type of fluid being discharged from the sand pack. A Rosemount pressure transducer was used to measure the pressure drop across the sample during geomechanics experiments. This allowed calculations of absolute and relative permeabilities. The transducer has an accuracy of 0.025%. Internal pressure transducers in the pumps allowed for the measurement of pore and confining pressures. The back pressure regulator is shown in Fig. 2.2. It is a normally closed valve, used to control and maintain upstream pore pressure. A spring-loaded diaphragm was used to control the pressure setpoint, by turning a screw to increase or decrease the set pressure. The spring holds the valve in the closed position. The sensing
diaphragm transmits the upstream pore pressure to the spring. When the upstream pore pressure overcomes the spring setting, the valve begins to open. The back pressure regulator allowed the flow of oil as well as water at elevated pore pressure. This enabled calculation of absolute and relative permeabilities. The range of set pressures was between 50 and 6000 psi.

Figure 2.2: Backpressure regulator: normally-closed valve maintains pressure upstream (http://www.plastomatic.com/bprvspr.html).

The flow schematic shown in Fig. 2.3 shows the setup used for this study. It involves all the deformation and flow-related equipment mentioned in sections 2.1.1 and 2.2.1. Water is represented by blue and oil is represented by red. The oil used in the study was Dow Corning silicone oil (DC-200) with a dynamic viscosity of 50 centipoise. DC-200 does not show any reactivity with the sand (Khan, 2009). The oil was dyed with a red dye to enable better visualization. The water used was distilled water with a viscosity of 1 centipoise.
For oil flow into the sample (Fig. 2.4), water was pumped from the upstream pore pressure pump, displacing oil from the horizontal oil-water separator. The oil then flowed into the sample. The outlet pore pressure was controlled by back-pressure regulator. The pressure drop across the sample was measured by the Rosemount pressure transducer mounted across the sample. Water flow was accomplished similarly but without inclusion of the separator in the flow path (Fig. 2.5).
Figure 2.4: Oil flow path is highlighted. Blue represents water while red represents oil.
Figure 2.5: Experimental setup schematic showing water flow path.

Oil refill took place in two steps. In the first step, oil was refilled into the vertical oil-water column by using the pore pressure upstream pump and an oil refill container. The two 3-way valves were lined up accordingly as shown in the Fig. 2.6a.
In the second step, oil was refilled into the oil-water separator by pumping water from the upstream pore pressure pump as shown in Fig. 2.6b. This pumped water displaced oil in the oil-water column, pushing it into the oil-water separator. This process went on until the oil-water separator was completely filled with oil. Water was refilled into the upstream pore pressure pump by refilling from a water container as shown in Fig. 2.7.
Figure 2.6b: Experimental setup schematic showing oil refill flow path.
2.2 Definition of Parameters for Deformation and Flow

Following the rock mechanics convention, this work considers compressive stress and compression to be positive and tension to be negative. In a highly deformable material like loose sand, there can be significant area change during testing. The definition of engineering axial stress, $\sigma_{\text{engg}}$, is based on the initial (nominal) area, $A_o$ of the sample as,

$$\sigma_{\text{engg}} = \frac{F}{A_o},$$  \hspace{1cm} (2.1)

where
F = axial load provided by the load-frame.

The “true” axial stress accounts for the instantaneous area of the sample during the deformation experiments as

\[
\sigma_{a,\text{true}} = \frac{F}{A_{\text{true}}}. \quad (2.2)
\]

The true area, \( A_{\text{true}} \) can be determined in the following way. The axial strain, \( \varepsilon_a \) can be written as

\[
\varepsilon_a = \frac{L_o - L}{L_o}, \quad (2.3)
\]

where

\[
L_o = \text{initial (nominal) length of the sample, and}
\]

\[
L = \text{instantaneous length of the sample during deformation.}
\]

The change in length of the sample, \( \Delta L \) is

\[
\Delta L = L_o - L = \varepsilon_a L_o. \quad (2.4)
\]

The length of the sample, \( L \) as a function of deformation is given by

\[
L = L_o - \varepsilon_a L_o = L_o (1 - \varepsilon_a). \quad (2.5)
\]

The volumetric strain, \( \varepsilon_v \) can be written as

\[
\varepsilon_v = \frac{V_o - V}{V_o}, \quad (2.6)
\]

where

\[
V_o = \text{initial volume of the sample } = \frac{\pi D^2 L_o}{4}, \quad (2.7)
\]

\[
V = \text{instantaneous volume of the sample during deformation, and}
\]

\[
D = \text{initial diameter of the sample.}
\]

The change in volume of the sample, \( \Delta V \) is

\[
\Delta V = V_o - V = \varepsilon_v V. \quad (2.8)
\]

Consequently, the volume of the sample, \( V \), as a function of deformation is

\[
V = V_o - \varepsilon_v V_o = V_o (1 - \varepsilon_v). \quad (2.9)
\]
Dividing volume by length (using Eq. 2.5 and 2.9) gives area as a function of deformation as

$$A_{true} = \frac{V_o (1 - \varepsilon_v)}{L_o (1 - \varepsilon_a)}.$$  \hspace{1cm} (2.10)

Young’s modulus, $E$, can be computed for the unconsolidated sand sample undergoing elastic deformation. Secant modulus was calculated for the triaxial deformation ($E_{ta}$) and is given by

$$E = \frac{\sigma_{a, true}}{\varepsilon_a}.$$  \hspace{1cm} (2.11)

For radial extension, an equation for Young’s modulus ($E$) can be derived by following these few steps. The change in axial strain ($\Delta \varepsilon_a$) with change in stresses can be written as

$$E \Delta \varepsilon_a = \Delta \sigma_a - 2\nu \Delta \sigma_c,$$  \hspace{1cm} (2.12)

where

- $\Delta \sigma_a = \text{change in axial stress}$,
- $\Delta \sigma_c = \text{change in confining stress}$, and
- $\nu = \text{Poisson’s ratio}$;

while the change in radial strain with change in stresses can be written as

$$E \Delta \varepsilon_r = \Delta \sigma_r - \nu(\Delta \sigma_a + \Delta \sigma_c).$$  \hspace{1cm} (2.13)

where

- $\Delta \varepsilon_r = \text{change in radial strain}$

The Eq. 2.12 and 2.13 simplify when the change in axial stress is zero to give (since in radial extension experiments, the axial stress remains constant)

$$E \Delta \varepsilon_a = -2\nu \Delta \sigma_c,$$  \hspace{1cm} (2.14)

$$E \Delta \varepsilon_r = (1 - \nu) \Delta \sigma_c$$  \hspace{1cm} (2.15)

two equations with two unknowns (and three measurements). Since volumetric strain was measured, so it can be expressed as
\[ \Delta \varepsilon_v = \Delta \varepsilon_a + 2 \Delta \varepsilon_r, \text{ or} \]
\[ \Delta \varepsilon_v = \frac{\Delta \sigma_c}{E} 2(1 - 2\nu). \tag{2.16} \]

where
\[ \Delta \varepsilon_v = \text{change in volumetric strain} \]

Solving Eq. 2.14 for Poisson’s ratio and substituting into Eq. 2.16, we get
\[ E - 2\left( \frac{\Delta \varepsilon_v}{\Delta \varepsilon_a} - \frac{\Delta \sigma_c}{\Delta \varepsilon_a} \right) = 0. \tag{2.17} \]

Eq. 2.17 can be solved for \( E \) to obtain Young’s modulus for radial extension experiments.

The volumetric strain was calculated by measuring the change in confining fluid volume in the triaxial cell. A LVDT was installed at the confining pressure pump, and calibrated to read the volume of fluid in the pump. For example, as the confining fluid was expelled from the triaxial cell due to sample’s volume increase, the volume of water in the pump increased. The confining volume readings that were obtained by the data acquisition system included an additional term owing to the axial displacement of the sample. This additional term can be obtained by taking a product of difference in axial displacement and initial cross-sectional area of the sample,
\[ \varepsilon_v = \frac{\Delta V}{V_o} = \frac{(V_{c2} - V_{c1}) - (\delta_2 - \delta_1)A_o}{A_oL_o}, \tag{2.18} \]

where
\[ \Delta V = \text{Change in volume of the sample during deformation}, \]
\[ V_{c2} = \text{Final confining chamber volume}, \]
\[ V_{c1} = \text{Initial confining chamber volume}, \text{ and} \]
\[ \delta = \text{Axial displacement of the sample}. \]

When a material is axially compressed, it tends to expand in the directions perpendicular to the axial compression. Poisson’s ratio is the ratio of lateral strain to axial strain for triaxial compression. It is given by
\[ \nu = -\frac{\varepsilon_{\text{lateral}}}{\varepsilon_a}. \tag{2.19} \]
Volumetric strain as a function of normal strains is given by
\[ \varepsilon_v = \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz}, \]  
(2.20)

where
\[ \varepsilon_{xx} = \text{normal strain in the x-direction,} \]
\[ \varepsilon_{yy} = \text{normal strain in the y-direction,} \]
\[ \varepsilon_{zz} = \text{normal strain in the z-direction.} \]

Since radial strain, \( \varepsilon_r \), is the strain in both the y- and the z-directions, Eq. 2.20 can be written as
\[ \varepsilon_v = \varepsilon_a + 2\varepsilon_r. \]  
(2.21)

Solving for the radial strain gives
\[ \varepsilon_r = \frac{\varepsilon_v - \varepsilon_a}{2}. \]  
(2.22)

So, Poisson's ratio for uniaxial loading condition can be determined from
\[ \nu = \frac{\varepsilon_v - \varepsilon_a}{2\varepsilon_a}. \]  
(2.23)

Mean stress, \( p \) is the average of the axial stress and confining stresses. It is given by
\[ p = \frac{\sigma_a + 2\sigma_c}{3}, \]  
(2.24)

where
\[ \sigma_a = \text{axial stress on the sample, and} \]
\[ \sigma_c = \text{confining pressure around the sample.} \]

The effective mean stress takes into account the pore pressure in the sample, and was calculated as
\[ p' = \frac{\sigma_a - P_p + 2(\sigma_c - P_p)}{3}. \]  
(2.25)

The differential stress was calculated by using
\[ q = |\sigma_a - \sigma_c|. \]  
(2.26)

The general form of the linearized Mohr-Coulomb is given by
\[ S_1 = nS_3 + C_o, \]  
(2.27)
where $S_1$ is the peak failure stress, $S_3$ is the confining stress, $n$ is the slope of $S_1$ versus $S_3$ failure plot and $C_0$ is the Unconfined Compressive Strength (UCS).

The coefficient of internal friction was calculated from the slope of $S_1$ versus $S_3$ by using
\[ \mu_i = \frac{n-1}{2\sqrt{n}}. \]  
(2.28)

The porosity of the sand samples was calculated using
\[ \phi = \frac{V_b - V_g}{V_b}, \]  
(2.29)

where
\[ V_b = \frac{\pi D^2 L}{4} = \text{Bulk volume of the sand sample, and} \]  
(2.30)
\[ V_g = \frac{\text{mass}_{\text{sand}}}{\text{density}_{\text{sand}}} = \text{Grain volume of the sand in the sample}. \]

A quartz density of 2.65 g/cm$^3$ is used for the calculations.

An equation to calculate Biot’s parameter can be derived using the steps outlined in this section. The effective stresses, $\sigma$ can be written in terms of total stresses, $S.$
\[ \sigma_{xx} = S_{xx} - \alpha_p P_p, \]  
\[ \sigma_{yy} = S_{yy} - \alpha_p P_p, \]  
and
\[ \sigma_{zz} = S_{zz} - \alpha_p P_p, \]  
(2.31)

where
\[ \alpha_p = \text{Biot’s parameter, and} \]  
\[ P_p = \text{pore pressure}. \]

For an elastic solid, volumetric strain can be described by Eq. 2.20. From Hooke’s Law, for an isotropic media
\[ E\varepsilon_{xx} = \sigma_{xx} - \nu(\sigma_{yy} + \sigma_{zz}), \]  
\[ E\varepsilon_{yy} = \sigma_{yy} - \nu(\sigma_{xx} + \sigma_{zz}), \]  
and
\[ E\varepsilon_{zz} = \sigma_{zz} - \nu(\sigma_{xx} + \sigma_{yy}). \]  
(2.32)

Substituting Eq. 2.32 into Eq. 2.31,
For isotropic loading, \( \sigma = \sigma_{xx} = \sigma_{yy} = \sigma_{zz} \).

The volumetric strain can be simplified as
\[
\varepsilon_v = \frac{1}{E} (1 - 2\nu) (3\sigma) = \frac{3(1 - 2\nu)}{E} \sigma.
\]  
(2.34)

The bulk modulus, \( K \) is defined as
\[
K = \frac{E}{3(1 - 2\nu)} = \frac{\sigma}{\varepsilon_v}.
\]  
(2.35)

Expanding Eq. 2.31 by incorporating the definition of effective stress,
\[
\varepsilon_v = \frac{3(1 - 2\nu)}{E} (S - \alpha_p p_p).
\]  
(2.36)

If the external stresses are held constant and only the pore pressure is changed, we can take \( \frac{\partial}{\partial P} \) of Eq. 2.36,
\[
\frac{\partial \varepsilon_v}{\partial P_p} = \frac{3(1 - 2\nu)}{E} (-\alpha_p),
\]  
(2.37)

\[
\frac{\partial \varepsilon_v}{\partial P_p} = -\frac{\alpha_p}{K}, \text{ and}
\]  
(2.38)

\[
\alpha_p = -K \frac{\partial \varepsilon_v}{\partial P_p}.
\]  
(2.39)

Eq. 2.39 is used to calculate Biot’s parameter for the pore pressure increase experiments.

The absolute permeability, \( k \) was determined by Darcy’s law:
\[
k = \frac{Q \mu L}{A \Delta P},
\]  
(2.40)

where

\( Q \) = flow rate at the outlet of the sample,

\( \mu \) = viscosity of the fluid flowing through the sample (oil or water), and

\( \Delta P \) = pressure drop across the sample.

Water saturated sand samples were deformed to a specific value of axial strain (or to a specific value of pore pressure), and were then flooded with oil. The oil flooding continued until all the mobile water was collected at the outlet. This is the state of the
initial water saturation ($S_{wi}$). It is determined to be the state when 99% of the discharged fluid from the sample is oil (Khan, 2009).

The end point oil permeability (effective permeability to oil, $k_o$) is given by Eq. 2.40 with the appropriate flow rate, viscosity and sample dimensions. The relative permeability to oil is calculated by normalizing $k_o$ by the absolute permeability, $k$ (Johnson et al., 1959)

$$k_{ro} = \frac{k_o}{k},$$  \hspace{1cm} (2.41)

where

$k_{ro} =$ relative permeability to oil.

After the sample had achieved steady state for oil flooding, it is flooded with water until 99% of the effluent is water. The end point water permeability (effective permeability to water, $k_w$) is given by Eq. 2.40 with the appropriate flow parameters, and relative permeability, $k_{rw}$ is given by the ratio of the effective end-point permeability to water to absolute permeability (Eq. 2.41).

Using the quantities of fluid collected at the outlet during oil and water floods, phase saturations can be calculated. During an oil flood, the amount of water collected represented the oil that had displaced water in the pore space. Similarly, during a water flood, the amount of oil collected represented the water that had displaced oil in the pore space. Thus, initial water saturation and residual oil saturation can be calculated using mass balance. The pore volume is the product of specimen bulk volume and porosity. The initial water saturation ($S_{wi}$) is given by

$$S_{wi} = 1 - \frac{V_w}{V_p}.$$ \hspace{1cm} (2.42)

Residual oil saturation ($S_{or}$) is given by

$$S_{or} = \frac{V_w - V_o}{V_p},$$ \hspace{1cm} (2.43)

where
\[ V_p = \text{pore volume}, \]
\[ V_w = \text{volume of water collected during oil flood, and} \]
\[ V_o = \text{volume of oil collected during water floor}. \]

Relative permeability curves as a function of saturation can be plotted from experimentally measured end point values by using the following Corey type equations:

\[
k'_{rw}(S_w) = k_{rw}(S_{or})(\frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}})^{3.5}, \tag{2.44}
\]
\[
k'_{ro}(S_w) = k_{ro}(S_{wi})(\frac{1 - S_w - S_{wi}}{1 - S_{wi} - S_{or}})^3, \tag{2.45}
\]

where

- \( k_{rw} \) = Relative permeability to water,
- \( k_{ro} \) = Relative permeability to oil,
- \( S_{or} \) = Residual oil saturation,
- \( S_{wi} \) = Initial water saturation,
- \( k_{rw} \) = End point relative permeability to water, and
- \( k_{ro} \) = End point relative permeability to oil.

### 2.3 Sample Preparation

Sample preparation is an important part of this experimental investigation, since it influences the ability to have repeatable results. Samples having consistent properties analogous to reservoir conditions are necessary to perform repeatable, accurate experiments. Sample preparation method influences compaction of the sample and thus dictates the porosity, permeability and strength of the sand pack.

Commonly used methods for making sand samples are dry tamping, wet tamping, wet vibration, water pluviation, and slurry deposition (Yaich, 2008). Based on the results from Oldakowski (1994), Tohidi-Baghini (1998), Yaich (2008) and Khan (2009), wet vibration method was chosen for preparing sand pack samples for use in this study.
Unconsolidated Athabasca sand was used to prepare sand packs for this study. The sand packs measure about 3 inches in length and 1.5 inches in diameter. A small amount of sand, usually around 150 grams is weighed. A rubber jacket was fastened to the bottom loading ram using a clamp. The bottom loading ram was placed in the bottom plate of the triaxial cell to provide stability. This assembly was placed on a vibrating table and a small amount of water was poured, followed by a small amount of sand. The sand was poured slowly to provide time for it to settle down inside the rubber jacket. Water was also poured at the same time, making sure that the water level stayed above the sand level in the jacket. This was done to ensure 100% water saturation and proper settling of the sand. After obtaining about 3 inches of sand deposition, the assembly was left on the vibrating table for a further 10 minutes. The whole process took about 30 minutes to complete. The sand packs prepared using this method had a porosity around 32 percent and an initial permeability of around 4-5 Darcies, which is analogous to the reservoir conditions in Athabasca Oil Sands.

After the sample was prepared, the top loading ram was placed on top of the sand pack and securely fastened using a hose clamp. The outer Aluminum cylinder was placed around and enclosed on top by the top plate. The top plate was secured in place by using six nuts. This assembly was placed in a load frame and connections are made for the pore pressure, confining pressure and pressure transducer ports. The valves on the pore pressure and confining pressure lines could be turned off to maintain the pressures.

The Figures 2.8a and 2.8b show the grain size distribution of Athabasca sand used in this study and Oldakowski (1994) respectively. Most of the particles are between 100 and 250 micrometer in sizes.
Figure 2.8a: Grain size distribution of Athabasca sand used in this study. Two samples of sand were sieved. Both samples show almost identical grain size distribution curve.

Figure 2.8b: Grain size distribution for reconstituted Athabasca sand samples from Oldakowski (1994).
The uniformity coefficient, $C_u$, is a measure of degree of uniformity in a granular material and was calculated using

$$C_u = \frac{D_{60}}{D_{10}}. \quad (2.46)$$

The coefficient of curvature, $C_c$, another shape parameter is defined as

$$C_c = \frac{D_{50}^2}{D_{60}D_{10}}. \quad (2.47)$$

$D_{60}$, $D_{30}$, $D_{10}$ are the particle-size diameter for which 60, 30 and 10 percent of the sample was finer respectively. The Uniformity coefficient for Athabasca sand is 1.6 and the coefficient of curvature is 0.9. A larger uniformity coefficient means that the grain size distribution is wider and vice versa. A uniformity coefficient equal to 1, means that all the grains are of the same size, for example dune sand. On the other extreme is the glacier till for which uniformity coefficient can be as high as 30. In the Unified Soil Classification System (USCS), well-graded sands must have a $C_u$ value greater than 6 and a $C_c$ value from 1 to 3. The Athabasca sand is not well-graded, rather as suggested by these numbers and the slope of the grain size distribution curve, it is mostly uniformly-graded sand.

2.4 Experimental Procedure

The following is the procedure followed for performing a typical experiment in this study

1. The Athabasca sand was weighed on the mass balance.
2. The sand pack was prepared by using wet vibration method, making sure the water level stayed above the sand at all times during the process.
3. The triaxial cell was assembled with the sand pack.
4. The length of the sand pack sample was measured after the triaxial cell assembly by measuring the length of the upper loading ram, which was above the top plate.
5. The confining fluid, pore pressure and pressure transducer connections were made, and the confining chamber was filled with water.

6. Water was flowed through the sample for about 5 minutes to ensure that it stayed water saturated and to determine the permeability of the sample. The initial permeability and porosity of the sample stayed repeatable when using the wet vibration method.

7. The sample was isotropically loaded to about 3300 psi to over-consolidate the sample; and unloaded isotropically to the initial experimental state required for the experiment. Most of the experiments were performed on samples without over-consolidation. Initial conditions for axial stress, confining stress and pore pressure were set and appropriate loading such as triaxial compression, radial extension, or pore pressure increment was carried out.

8. The absolute permeability of the sample was measured by flowing water through it. The two-phase relative permeability of the sample was measured by flowing oil and water through it. Also, the fluid at the pore outlet was collected during the sand pack floods. The amount of water during an oil-flood and the amount of oil during a water-flood are measured and noted. This provided phase saturations.

The axial displacement of the sample was measured by using the axial displacement LVDT and recorded using the data acquisition system. This was also displayed on the load frame panel. The axial load applied during the experiment was measured by the S-beam load cell, and recorded using the data acquisition system. This was also displayed on the load frame panel. Confining and pore pressures were measured at the pump’s outlet using the built-in pressure transducer in the pump. The pressure across the sample was measured by a Rosemount pressure transducer. This allowed the calculation of absolute and relative permeabilities. The pore pressure pump was run in
constant flow rate mode when flowing water and oil through the sample to measure the permeabilities. The confining fluid volume was measured by an external LVDT mounted on the confining pressure pump piston. As the piston on the pump moved, so did the LVDT. This movement was calibrated to measure the confining fluid volume in the data acquisition system. The pore fluid flowing out of the sample was collected in burettes. The volume of water during oil-flood and the volume of oil during water-flood were noted visually and recorded manually. This allowed the calculation of sample phase saturations. The length of the sample was measured using an accurate steel ruler while the weight of the sample was recorded using a mass balance and recorded manually. This allowed the calculation of porosity of the sample.

2.5 Scanning Electron Microscope (SEM) Images

The scanning electron microscope (SEM) allows the examination of heterogeneous materials by scanning them using a beam of electrons, on a nanometer to micrometer scale. The SEM is generally used to take topographic images with a magnification anywhere in the range of 10 to 10,000 times. Fig. 2.9 shows a series of SEM images for different grain sphericity and roundness (Powers, 1953; Tsomokos et al., 2010).

![Figure 2.9: Estimation of sphericity and roundness of clastic grains (from Powers, 1953; Tsomokos et al., 2010).](image)
Dusseault et al. (1979) classified Athabasca Oil Sands as “locked sands” owing to their angular grain shapes. Shahu and Yudhbir (1998) showed that for angular grains, the angle of shear resistance is much higher. Guo and Su (2007) performed triaxial compression experiments and showed that angularity of grains tends to increase peak friction angle and affects the dilatancy characteristics of sand. Nouguier-Lehon et al. (2003) used discrete element methods (DEM) to study the effect of grain shape on the behavior of granular materials and found that angularity tends to increase the strength of samples. Figures 2.10 and 2.11 show the Athabasca sand presented by Dusseault (1979) and Agar et al. (1983) respectively. This is very similar to the images for Athabasca sand that were used in this study, as shown in Figures 2.12 and 2.14.

Figure 2.10: McMurray Formation (Athabasca Oil Sands); 360x magnification using SEM examination (Dusseault, 1979).
Figures 2.11 and 2.14 show the low sphericity and high angularity of the Athabasca sand grains. At several locations, the grains seem to be “locking” into each other, providing a stiff matrix. The interpenetrative contacts as defined in Fig. 2.13 can be observed in Figures 2.12 and 2.14 for the Athabasca sand used in this study.

Figure 2.12: Athabasca sand used in this study; 150x magnification using SEM examination. The scale bars shown in the images are 200 micrometers long.
Figure 2.13: Fabric of Athabasca oil sands: interpenetrative contacts are marked with arrows (Touhidi-Baghini, 1998; modified from Dueeeault and Morgenstern, 1978).

Figure 2.14a: Athabasca sand used in this study; 300x magnification using SEM examination. The scale bars shown in the images are 100 micrometers long.
Figure 2.14b: Athabasca sand used in this study; 300x magnification using SEM examination. The scale bars shown in the images are 100 micrometers long.
Chapter 3

Results and Discussion

Steam Assisted Gravity Drainage (SAGD) process causes stress changes in the unconsolidated sand reservoir, resulting in a complex interaction of geomechanics. This is coupled with multiphase flow under varying fluid pressure and stress conditions. Using the equipment and procedures described in chapter 2, experiments were performed on Athabasca sand packs using different stress paths. Deformation of oil sands such as Athabasca has been shown to be stress path dependent (Agar et al., 1986). The stress paths followed in this study were triaxial compression, radial extension, pore pressure increase and isotropic compression at confining stress magnitudes representative of depths in typical heavy oil reservoirs. These stress paths were designed to induce deformation representative of steam injection in shallow reservoirs. The deformation and flow results are described in the following sections.

Triaxial compression at constant pore pressure involves increasing mean effective stress, which is similar to the stress path during thermal expansion of a reservoir. Radial extension at constant pore pressure involves decreasing mean effective stress, which is similar to the effect of increasing pore pressure in a reservoir. Finally, we ran increasing pore pressure experiments with various confining and axial conditions to try to get the closest to the actual field stress path under steam injection.

3.1 Triaxial Compression and Radial Extension Stress Paths

In the triaxial compression stress path, the axial stress was increased while keeping the confining stress constant. This resulted in a path of increasing mean effective stress, which is what happens when thermal stresses cause expansion of the reservoir
during heavy oil recovery processes. Radial extension experiments represent a path of decreasing mean stress which roughly mimics the reducing effective stress path experienced during steam injection for SAGD operations for isotropic initial reservoir stresses (similar overburden and lateral stresses). Different Athabasca sand samples were isotropically loaded to predetermined stresses of 500, 1000 and 1500 psi. The confining pressure was then reduced to achieve the desired axial strain while keeping the axial stress constant.

The differential stress increased during the triaxial compression and radial extension stress paths, which caused shear failure in the sample. During the experiments, the deformation was stopped at 1, 2, 4, 6, 8 and 10 percent axial strain to measure end point relative permeability to water and oil respectively. The initial water saturation and residual oil saturation in the sample were also measured at these discrete deformation stages. In separate experiments, absolute permeability of the sand packs saturated with water, were also measured during the deformation. Permeability was measured in the axial direction only, which is the direction of the most compressive stress in the experiment. This direction corresponds to horizontal direction in the reservoir, since the most compressive stress in the Athabasca reservoir is the horizontal (Zoback et al., 1989).

3.1.1 Deformation Behavior

During the triaxial compression experiments, the sand packs were loaded isotropically to confining stresses of 100, 200, 400 and 800 psi, and the axial stress was increased at a displacement rate of 0.01 in/min. This provided slow deformation in the sand packs while allowing pore pressure which might develop to dissipate through the open port in the triaxial cell. The porosity of the sand packs was around 32%. The cross-sectional area of the sample changed during the deformation due to the high strains. True
differential stress is plotted in Fig. 3.1, which takes into account the instantaneous area of the sample as the sample is deformed.

All the stress-strain curves have a similar shape, showing initial elastic behavior followed by a plastic post-peak region. The strain-softening character after peak stress is not as pronounced as in the experiments conducted by Khan (2009) and Yaich (2008). The sand packs continue to deform after the peak stress is reached, but there is no significant drop in the stress carried by the samples. The small drop in stress is due to the weakening of the samples caused by the formation of shear bands. Shear banding responsible for the dilatant behavior of the sand packs usually starts forming at or after peak stress (Desrues and Viggiani, 2004). The shear bands continue to grow as the sample is deformed post peak stress. Shear bands are a type of strain localization which occurs in unconsolidated sand as a result of shear failure.

Dilatancy in this work is defined as when the compactive behavior reverses slope. It can be seen from the true differential stress versus volumetric strain plots (Fig. 3.1) that the sand samples compacted initially and then dilated as peak stress was reached. The amount of dilation was greater for samples at lower confining pressures. The small vertical drops seen in the curves were due to the measurement of flow properties at axial strains of 0, 1, 2, 4, 6, 8 and 10 percent. The peak stress occurs between 5 and 7 percent axial strain for lower confining pressures, while it occurs at 10.3% axial strain for 800 psi confining pressure.
Figure 3.1: True differential stress versus volumetric or axial strain plot, as the Athabasca sand samples underwent triaxial compression for four different confining pressures of 100, 200, 400 and 800 psi.

As the differential stress on the specimen increased, shear deformation of the samples caused an increase in the volume of the sand pack, resulting in dilation (Fig. 3.2). The degree of dilatancy decreases with increasing confining stress. The volumetric strain remains compactive for about 2% axial strain for confining pressures of 100, 200 and 400 psi, while it stays compactive until 5% for 800 psi confining pressure. Also, the samples at 100 and 200 psi confining pressures reached between -2 and -3% volumetric strain; the sample at 400 psi reached about -0.8% volumetric strain and the sample at 800 psi confining pressure reached +1.4% volumetric strain at 10% axial strain. This suggests that the dilatant behavior is much more pronounced for oil sands reservoirs near the surface; and the dilative behavior diminishes as the reservoir becomes deeper. Dilatancy is more pronounced at lower effective confining stresses, was also observed by Agar et
al. (1987). The start of dilatancy always preceded the peak stress during our study’s triaxial experiments. This is also observed in the results of Khan (2009), Yaich (2008) and Agar et al. (1987).

Figure 3.2: A plot of volumetric strain versus axial strain for triaxial compression. Positive strains are compactive, while negative strains are dilatant.

As the confining stress was increased, the sand packs increased in stiffness as evidenced by the increasing Young’s modulus. The Young’s moduli were calculated for each of the sand packs during the initial linear segment of the axial stress versus axial strain curve. As shown in Fig. 3.3, the Young’s modulus curve flattens out for higher confining stresses. This shows that the stiffness increase with depth of the reservoir is not linear, but follows a flatter slope. A comparison of Young’s Modulus is also presented with other studies in Fig. 3.3. The data for Young’s Modulus agrees well with some of the earlier work especially Oldakowski (1994). Differences in grain size distribution,
grain shape, texture, presence of bitumen, different methods of sample preparation, different initial porosities can be attributed as factors responsible for a range of Young’s Moduli values for Athabasca oil sands samples. Oldakowski (1994) used reconstituted bitumen-free sand samples with grain size distribution which is very similar to the one used in this study, shown in Fig. 2.8b. Chalaturnyk (1996) summarized his own results along with results from a number of researchers such as Agar (1984), Au (1984), Plewes (1987) and presented the curve shown in Fig. 3.3. In his words, the much higher stiffness can be attributed to “excessive cyclic compressive stresses used to re-compress the specimens prior to shear testing. This created a structure of substantial initial stiffness which is likely unrepresentative of the in situ stiffness.”

![Figure 3.3](image.png)

Figure 3.3: Comparison of Young's Modulus versus confining pressure during triaxial compression stress path for this and other studies.
Shear failure tests were fit to a linearized Mohr-Coulomb envelope as shown in Fig. 3.4. The best fit linear envelope was

$$\sigma_1 = 2.87 \sigma_3 + 133.91,$$

where the slope of 2.87 represents an internal friction coefficient ($\mu_i$) of 0.55 based on Eq. 2.28. This corresponds to an angle of internal friction of 28.8°. Fung et al. (1994) used porosity to be 32% and friction angles to be 16° and 30° for their simulation cases when studying the coupled geomechanical-thermal deformation for heavy-oil reservoirs. Yale et al. (2010) reported a friction angle near 30° for the majority of their samples, but their range for friction angle was from 26° to 41°.

![Figure 3.4: Effective maximum principal stress plotted against effective minimum principal stress for the Athabasca sand samples used in this study.](image)

During radial extension, the deformation stresses calculated using the actual area of the sample increased sharply during the first 2% axial strain. The differential stress at
failure is about 60% of the value of the initial confining pressure. Similar to the triaxial experiments, the plastic behavior is relatively “flat”. The initial slopes of the curves in Fig. 3.5 appear to be almost the same, so the Young’s moduli are similar for the different confining pressure experiments (Fig. 3.7). The initial slopes of the stress-strain curves are much steeper than the triaxial stress-strain curves since radial extension represents a path of unloading. The stress-volumetric strain curves show dilatant behavior from the beginning. Fig. 3.8 shows a curve fitted to the $S_1$ versus $S_3$ plot for radial extension experiments. These numbers are very similar to the curve fit to the triaxial compression results in Fig. 3.4.

As the confining stress was decreased, the differential stresses increased and caused the sand packs to dilate immediately. There was no compactive behavior. The amount of dilation was much greater than the triaxial compression cases, reaching between -10 and -12 percent volumetric strains at 10% axial strain. This higher dilatancy is to be expected since radial extension experiments involved an unloading path. Khan’s (2009) lower fine Ottawa sand samples also showed about 10% dilative volumetric strain, at 10% axial strain for 200 psi initial confining pressure. He observed that at higher confining pressures (of 500 psi), the dilation is less. However, in this study the dilation was more as the confining pressure was increased from 500 to 1500 psi even though the slope of the dilatant behavior decreased slightly for higher confining pressure. So, for decreasing mean stress path, the depth of the reservoir does cause rate of dilatant behavior (slope of the curve in Fig. 3.6) to decrease but the dilative effect still occurs for much greater depths than is the case for increasing mean stress path (triaxial compression). The amount of dilation happening at greater depths is much greater for radial extension as compared to triaxial compression.
Figure 3.5: True differential stress versus volumetric or axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.

Figure 3.6: Volumetric strain versus axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.
Figure 3.7: Young’s Modulus during Radial Extension stress path.

Figure 3.8: Effective (or total) maximum principal stress (differential stress plus confining pressure at failure) versus effective (or total) minimum principal stress (confining pressure at peak differential stress) shows a linear trend.
### 3.1.2 Absolute Permeability Changes

Absolute permeability was measured for water saturated Athabasca sand samples at 0, 1, 2, 4, 6, 8 and 10 percent axial strains at various confining stresses. Different sand samples were used for each experiment at different confining stress. Fig. 3.9 shows normalized absolute permeability versus axial strain during the triaxial compression path. The initial permeabilities vary between 5 and 7 Darcies, which are fairly typical for Athabasca sand. Oldakowski’s (1994) Athabasca samples had permeability up to 4 Darcies. For 100 and 200 psi confining pressures, the permeabilities drop by 10% at 2% axial strain, and increase by as much as 20% at 10% axial strain, compared to the initial values. Yaich’s (2008) results show initial permeability decrease of about 5% and subsequent increases of 8 to 12%, at 10% axial strain. Those experiments were performed with lower fine Ottawa sand, which is similar in grain size distribution to Athabasca sand.

The 400 psi confining pressure sample’s permeability dropped only about 1% during the initial compaction, and still increased by about 20% compared to the initial value (Figure 3.10). The initial decrease in permeability is due to the compaction of the sample as the mean stress was increased. The permeabilities increased thereafter, because of the dilation of the samples in response to the increasing differential stress. The dilation happened because of the shear deformation and rearrangement of the sand grains, and provided a preferential path for the flow of fluids.

There was a 10% drop in absolute permeability for 800 psi confining pressure sample (Fig. 3.9). This is consistent with the fact that even though the volumetric strain shows a reversal in trend after sample failure (Fig. 3.1), the strain value is still positive (compactive). The 200 psi confining pressure results by Khan (2009), which showed a continued drop in absolute permeability are only seen at much higher confining pressures in this study. This might be because of the different texture of the Athabasca sand grains.
This change in behavior at higher confining pressure suggests that for deeper oil sands reservoirs undergoing thermal recovery, the increase in production rate due to dilation might not be possible.

Figure 3.9: Normalized permeability plots for different confining pressures, during triaxial compression.

Sieve analysis was performed post triaxial compression experiments, and results compared with an undeformed Athabasca sand sample. It can be seen from Fig. 3.10 that there is a small amount of grain crushing happening at higher confining pressures, especially at 800 psi. Grain crushing and the generation of granular debris would inhibit fluid flow as shown in Fig. 3.9. It might be one of the contributing factors for lower permeability values for 400 psi and 800 psi confining pressure cases, but closer packing at higher stress is probably the main cause.
In the radial extension experiments, the initial permeabilities vary between 5 and 7.5 Darcies, which are similar to the ones obtained for triaxial compression samples. The increase in absolute permeability at 10% axial strain, during radial extension experiments ranged from 20 to 50 percent (Fig. 3.11). The permeability enhancement for the 500 psi initial pressure test was 50%. Oldakowski’s (1994) isotropic experiments, with unloading from 4 MPa (580 psi) to 0.2 MPa (29 psi) effective stress, showed similar permeability increases of 13% to 70%. Khan (2009) also observed a similar 30% increase in permeability at 10% axial strain for lower fine Ottawa sand, at 500 psi confining pressure. However, his sample showed a volumetric strain of -6% as compared to -10% in this study. The permeability enhancement for the 500 psi initial stress sample was the largest, while it was the smallest for 1500 psi sample. Similar to the behavior observed in
the triaxial tests, the permeability enhancement due to dilation diminishes with the depth of the reservoir, but contrary to the higher confining stress triaxial test, there is no permeability decrease – all tests show permeability increase.

Figure 3.11: Absolute permeability versus axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.

### 3.1.3 Relative Permeability Changes

The end point relative permeability to water and oil were measured during the triaxial compression at 0, 1, 2, 4, 6, 8 and 10 percent axial strains. The water saturated samples were deformed to the reference axial strain, and oil flooded to the initial water saturation, and then water flooded to the residual oil saturation. The measurements of end point $k_{ro}$ and $k_{rw}$ were made at initial water saturation and residual oil saturation respectively.
The trend followed by the relative permeability curves is similar to the absolute permeability curves. The relative permeabilities decrease during compaction and increase during dilation, also seen in Khan (2009) for lower fine Ottawa sand. The relative permeabilities for 800 psi confining pressure sample do not increase, consistent with the absolute permeability result. After a large initial reduction, the \( k_{rw} \) curves in Fig. 3.12 increase much more than the \( k_{ro} \) curves in Fig. 3.13. An increased effective permeability to water (inferred from increased relative permeability) would increase hydraulic conductivity and permit injection pore pressures to travel further into the reservoir (Chalaturnyk and Scott, 1997). The samples corresponding to deeper depths showed lower end point relative permeabilities.

As the samples compact with increasing mean stress, the pore spaces reduce and increase the tortuosity of the flow paths. This causes a decrease in the \( k_{ro} \) and \( k_{rw} \) during the initial 2% axial strain. After the onset of dilation, the relative permeabilities increase due to increased pore throat sizes and pore connectivity. The shear bands provide a preferential pathway for oil and water flow, which results in an increased relative permeability to each phase.
Figure 3.12: End point relative permeability to water during triaxial compression for different confining pressures.

Figure 3.13: End point relative permeability to oil during triaxial compression for different confining pressures.
For radial extension, the relative permeabilities increased right from the beginning of the experiment, also seen in Khan (2009) for lower fine Ottawa sand. The end point relative permeabilities are higher, compared to the triaxial compression, since the samples dilated from the beginning, leading to higher volumetric strains and larger permeability increases. The shear bands provide a preferential pathway for oil and water flow, which resulted in increased relative permeability to each phase. The $k_{rw}$ curves in Fig. 3.14 exhibit a greater increase (especially up to 1% axial strain) than the $k_{ro}$ curves in Fig. 3.15. The initial large change is similar to the triaxial compression experiments indicating that during SAGD, the largest change in $k_{rw}$ happens during the startup phase. The effect of increasing mean stress (triaxial compression) is to cause a large initial decrease in $k_{rw}$ while decreasing mean stress (radial extension) causes a large initial increase in $k_{rw}$. The 1500 psi confining pressure sample showed lower end point relative permeabilities. This is consistent with the finding from previous sections, showing shear-induced permeability effects to decrease with increasing depth.
Figure 3.14: End point relative permeability to water versus axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.

Figure 3.15: End point relative permeability to oil versus axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.
3.1.4 Residual Oil Saturation

The residual oil saturation refers to the amount of trapped oil, which affects the ultimate recovery from a reservoir. A lower residual oil saturation results in higher final recovery from a reservoir. The residual oil saturation in a reservoir can range from 15 to 50 percent (Wilson et al, 1990). Residual oil saturation depends on the initial oil saturation, pore size distribution, pore connectivity and capillary pressure. During sample compaction, the pore sizes reduce and result in creation of some dead end pores. This increases the residual oil saturation. When the sample dilates, the rearrangement of grains provides better pore connectivity which decreases the trapped oil, and lowers the residual oil saturation (Li et al, 2004). Larger pore throats are associated with smaller capillary pressures, which results in lower capillary entrapment in the pore network, thereby reducing the residual oil saturation.

For the triaxial loading paths, the residual oil saturation increased during compaction and decreased during dilation (Fig. 3.16). There is a large initial increase in residual oil saturation during increasing mean stress path. This initial increase in residual oil saturation for lower confining pressures of 100, 200 and 400 psi was between 30 and 50 percent. The residual oil saturation for 800 psi sample decreased during compaction and did not recover since there was negligible dilation. A decrease in residual oil saturation occurred for 100, 200 and 400 confining pressure samples during dilation. When compared to the initial value, the $S_{or}$ remained almost the same for 100 and 200 psi cases. But the decrease in $S_{or}$ for 400 psi case was particularly large; compared to the initial value the $S_{or}$ decreased by 40% at 10% axial strain. Khan (2009) observed a decrease of 21% in residual oil saturation for lower fine Ottawa sand, at 10% axial strain at 50 psi confining pressure.
For radial extension, the residual oil saturation decreased from the beginning since there was no compactive behavior (Fig. 3.17). The decrease in residual oil saturation for confining pressures of 500, 1000 and 1500 psi was between 28, 55 and 50 percent respectively. This is much higher than the triaxial compression samples. The differences are significant especially for the first 2% axial strain during which the residual oil saturation decreases during radial extension while it increases for triaxial compression. Khan (2009) observed a decrease of 50% in residual oil saturation for lower fine Ottawa sand, at 10% axial strain at 200 psi confining pressure. The greater decrease in residual oil saturation for radial extension experiments compared to triaxial compression experiments can be attributed to the decreasing mean stress path and higher dilation.
Figure 3.17: Residual oil saturation versus axial strain plot during radial extension for initial confining pressures of 500, 1000 and 1500 psi.

3.1.5 Initial Water Saturation

Porosity increases caused by deformation affects water saturation (Scott et al., 1991). The initial water saturation decreased during compaction and increased during dilation for samples tested at 100, 200 and 400 psi confining pressures (Fig. 3.18). The large decrease in $S_{wi}$ can be attributed to water in the smaller pores being squeezed out into the larger pores where it was swept by the displacing oil. This sweep would happen provided the capillary pressure in the larger pores was small enough to allow water to flow. The initial water saturation increase during dilation was larger for the 400 psi sample compared to the 100 and 200 psi samples. The initial water saturation decreased at all axial strains for 800 psi confining pressure since the sample underwent negligible dilation.
The initial water saturation was between 15 and 18 percent at 0% axial strain, and increased to 23% at 10% axial strain (Fig. 3.19). This amounted to an increase of 27 to 51 percent. As the sample dilated, the pore throat and pore body sizes increased causing more water to line up the surface of the sand grains. Also, as the shear bands formed, oil might channel through the higher porosity and higher permeability shear-deformation zones bypassing the water trapped in the unswept zones. The increase in initial water saturation was the lowest for 500 psi confining pressure sample since it experienced the least dilation.
3.1.6 Corey Type Curves for Relative Permeability

The Corey type curves for relative permeability are plotted in Figures 3.20 and 3.21 for the different confining pressures. The curves are plotted for three axial strains: 0% (undeformed), 2% (dilation) and 10% (dilation).

During triaxial compression, the relative permeability to oil curves moved downward for 2% axial strains as compared to 0% axial strains, which shows that the relative permeability to oil decreased during compaction. These $k_{ro}$ curves moved upwards for 100, 200 and 400 psi confining pressure samples, at 10% axial strain, showing that during dilation, the relative permeability to oil increased. This would facilitate an increase in the production rate during the SAGD process. The $k_{ro}$ curve for 800 psi sample did not exhibit any increase in oil permeability at 10% axial strain, since the sample did not dilate. The relative permeability to water curves do not show a trend
for 2% axial strain; however the $k_{ro}$ curves at 10% axial strains are moved downwards from the 0% axial strain curves. This shows that relative permeability to water decreased at 10% axial strain, regardless of the confining pressure.

For radial extension, the relative permeability to oil curves moved upward for 2% and 10% axial strains as compared to 0% axial strains, which shows that the relative permeability to oil increased during dilation. The relative permeability to water curves moved upwards for 500 psi sample, as the sample dilated. However, for 1000 and 1500 psi samples, the $k_{rw}$ curves moved downwards as the sample dilated. This shows that for deeper depths, the oil flow dominates and the transmission of water flow is subdued as the sample dilates.
Figure 3.20: Corey-type Relative permeability vs. saturation curves for triaxial compression experiments with confining pressures of A) 100 psi B) 200 psi C) 400 psi D) 800 psi.
Figure 3.21: Corey-type Relative permeability vs. saturation curves for radial extension experiments with initial confining pressures of A) 500 psi B) 1000 psi C) 1500 psi.
3.2 Pore Pressure Increase Stress Path

The pore pressure increase stress path is a path of decreasing mean stress, and increasing or decreasing differential stress depending on the initial boundary conditions of stress and strain. Steam stimulation processes for heavy oil recovery involve reducing the in-situ effective stresses to a range close to zero (Samieh et al., 1997). The pore pressure in the experiments was increased from 0 psi to a value such that either the effective confining stress or the effective axial stress became very close to zero (whichever occurred first). As mentioned in section 1.5.3, the vertical stress is the minimum stress in the Athabasca oil sands as it is a thrust faulting stress environment (Zoback at al., 1989) and the maximum effective horizontal stress exceeds the effective vertical stress by a factor of about 3 from the surface to at least 330 m depth (Brooker, 1975). So, the initial stress states were chosen such that the maximum principal stress is a multiple of the minimum principal stress, but does not fail prior to the start of the experiment. The failure stress can be calculated according to the Mohr Coulomb failure criterion (Fig. 3.4). For a minimum effective principal stress of 400 psi, this comes out to be 1282 psi and for a minimum effective principal stress of 800 psi, the failure stress is predicted to be 2430 psi.

The pore pressure increase experiments were conducted under various boundary conditions summarized in Fig. 3.22. For initial isotropic stresses corresponding to column A (in Fig. 3.22), the initial stresses were 400 psi and 800 psi. For initial anisotropic stresses corresponding to columns B and C, two distinct differential stresses were used in this study. For a minimum principal stress of 400 psi, the other stress (axial or confining depending on the orientation of the sand pack) was set to be 1000 psi. For a minimum principal stress of 800 psi, the other stress was set to be 1200 psi. So, the 400 psi samples
were much closer to the failure stress as compared to the 800 psi samples. The results are organized in the following sub-sections.

One way to analyze deformation experiments is to plot differential stress, $q$ versus effective mean stress, $p'$ (Fig. 3.23). All the ‘A’ samples which correspond to initial isotropic stress plot together in Fig. 3.23 but each I, II, III and IV looks different. The sign ’ denotes lower differential stress and higher mean stress experiments conducted at 800 psi for isotropic stress and 800 & 1200 psi for anisotropic stress. Regardless of the initial isotropic stress IA and IA’, IIA and IIA’, IIIA and IIIA’, IVA and IVA’ show similar deformation behavior. The curves follow similar trend on the $q$-$p'$ plot and undergo no or little differential stress change. For anisotropic experiments conducted at higher differential stress and lower mean stress (400 & 1000 psi), the curves generally exhibit immediately decreasing differential stress with increasing pore pressure except IB and IC ($q$ starts decreasing when $p'$ reaches 360 psi and 520 psi respectively). This is in contrast to anisotropic experiments conducted at 800 & 1200 psi where the samples do not fail immediately and are able to sustain the differential stress as the effective mean stress is reduced. The two exceptions are IIIC’ and IVC’ which show signs of failure immediately. This is very similar to IIIC and IVC samples in Figure 3.23a.

Biot’s parameter can be calculated (Eq. 2.39) for these pore pressure increase experiments, provided the sample is undergoing elastic deformation during the period of calculation. A number of the samples underwent failure from the beginning of the pore pressure increase. Calculation of Biot’s parameter is only done for these cases for the sake of completeness and to highlight the non-applicability in non-elastic deformation cases. Biot’s parameter is used in the concept of effective stress which indicates that pore pressure plays an important part in determining the effective stress on a rock. For non-porous sandstone, Biot’s parameter is close to 0 and pore pressure does not play a part in
defining effective stress on the rock. For a compliant unconsolidated sand (such as the Athabasca oil-sands used in this study), Biot’s parameter is high which shows that the pore pressure has significant influence on effective stress. The value for Biot’s parameter is plotted in Fig. 3.24 and ranges between 0.8 and 1.0. The values marked ‘f’ can be neglected since those samples underwent failure and were no longer elastic.
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<th>A: Isotropic Stress</th>
<th>B: Higher Axial Stress</th>
<th>C: Higher Confining Stress</th>
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<td>Zero axial strain</td>
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<td>Zero confining strain</td>
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Figure 3.22: Schematic-grid for pore pressure increase stress path experiments.
Figure 3.23: Differential stress versus effective mean stress (q-p’ plot) as the pore pressure was increased for all the boundary conditions defined in Fig. 3.22 for two different initial stresses of a) (Top) Isotropic stress of 400 psi; anisotropic stress of 400 psi & 1000 psi b) (Bottom) Isotropic stress of 800 psi; anisotropic stress of 800 psi & 1200 psi. 800 & 1200 psi experiments are marked by a ’ sign in their names. The naming convention for the samples in this figure follows Fig. 3.22.
Figure 3.24: Biot’s parameter values plotted for each pore pressure increase experiment. ‘f’ indicates that the sample failed during the pore pressure increase experiment and hence is no longer considered to be elastic. The sign ‘ indicates experiments conducted at 800 psi isotropic stress and 1200 & 800 psi anisotropic stress.

### 3.2.1 Low and High Isotropic Stress

The boundary conditions IA, IIA, IIIA and IVA (Fig. 3.22) representing initial isotropic stresses, are depicted in Figures 3.25 through 3.29. These loading scenarios were run for 400 and 800 psi axial stress, corresponding to reservoir depths of 400 and 800 feet respectively. These results are plotted together to determine the difference in behavior between low and high isotropic stress for pore pressure increase. The pore pressure was increased by flowing water through the sample at a constant flow rate of approximately 0.5 ml/min. The stress in the direction which was not subjected to constant stress changed as the pore pressure was increased from 0 psi to the initial isotropic boundary stress. This resulted in decreasing effective mean stress to a value close to zero. Each plot in Fig. 3.25 can be compared to the corresponding plot in Fig. 3.26 to show
similar behavior which is according to the applied boundary conditions. Referring to Figures 3.25 and 3.26, the stresses remained constant in ‘I’; confining stress started to increase appreciably when pore pressure reached around 100 psi in ‘II’; axial stress started to increase from the beginning but reached a peak and then started to decrease in ‘III’; both axial stress and confining pressure started to increase when pore pressure reached around 40 psi.

The deformation behavior can be interpreted more explicitly in the effective stress versus volumetric strain plots (Fig. 3.27 and 3.28). The plots ‘I’ denoting constant stress boundary conditions do not show any signs of failure since the differential stress remains zero. The plots ‘II’ show increasing differential stress which represents non-failure state of the samples while the plots ‘III’ show peak and subsequently decreasing differential stress which represents failure state of the sample. For plots ‘III’, the differential stress that the sample can support decreases as the pore pressure was increased. For 400 psi sample (Fig. 3.27III), the maximum differential stress is 50 psi at a pore pressure of 200 psi, while for 800 psi sample (Fig. 3.28III) the maximum differential stress is 100 psi at a pore pressure of 400 psi. Since zero strains were maintained for plots ‘IV’, we see negligible volumetric strain and no trend for any of the plotted values. Another way to describe failure is to make a q versus p’ plot (Fig. 3.29). The behavior of plots I, II and III in both Fig. 3.29A and 3.29B is very similar. However, plot IV shows a peak differential stress of only 20 psi for 400 psi case while it keeps on increasing for the 800 psi case. As mentioned previously for Fig. 3.27 and 3.28, the sample subjected to boundary condition II (constant axial stress, zero radial strain) does not show failure while sample subjected to boundary condition III (zero radial strain, constant confining stress) shows failure after reaching peak differential stress.
Figure 3.25: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 400 psi initial isotropic stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero axial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.26: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 800 psi initial isotropic stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero axial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.27: Maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 400 psi initial isotropic stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.28: A plot showing maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 800 psi initial isotropic stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.29: Plots for pore pressure increase experiments corresponding to IA, IIA, IIIA and IVA boundary conditions for initial isotropic stress of A) 400 psi B) 800 psi. The symbol ' in the naming convention denotes initial isotropic stress of 800 psi.
3.2.2 Lower Mean Stress with Higher Initial Differential Stress

The pore pressure increase experiments were performed at a) lower mean stress with higher initial differential stress (this section) b) higher mean stress with lower initial differential stress (next section: section 3.2.3). Lower mean stress with higher initial differential stress experiments were conducted for two scenarios a) axial stress greater than confining stress (Fig. 3.30, 3.32 and 3.34A) b) confining stress greater than axial stress (Fig. 3.31, 3.33 and 3.34B). Since vertical stress is the minimum in Athabasca oil sands, the samples can be considered oriented vertically or horizontally so as to satisfy this condition.

These experiments can be analyzed by plotting the stresses and pore pressure versus time to see the effect of pore pressure increase as the experiment progressed (Fig. 3.30 and 3.31). For ‘I’ samples, the constant stresses remained at their initial values as the pore pressure was increased. However the axial stress changed when the pore pressure reached around 250 psi. In both cases, the differential stress that the sample could sustain started to decrease indicating failure. This happened at \( P_p = 220 \) psi for higher axial stress sample and at \( P_p = 280 \) psi for higher confining stress sample. For ‘II’ samples, the non-constant stress that is the confining stress started to change as the pore pressure was increased. The effect of this change in pore pressure was a decreasing differential stress (Fig. 3.32II and 3.33II). Similar behavior can be seen for ‘III’ samples except that the non-constant stress in this case is the axial stress (Fig. 3.30III and 3.31III). For ‘IV’ samples, the differential stress (inferred from the difference between axial stress and confining pressure) can be seen to be decreasing more appreciably for higher axial stress samples (Fig 3.30IV and 3.31IV). Generally it can be seen that the higher stress from Fig. 3.30 and 3.31 decreases (or stays constant) and the lower stress increases (or stays constant) due to the increasing pore pressure. The result of this can be seen in the Figures.
3.33 and 3.34 where the differential stress either stays constant or decreases. It is only for the ‘I’ sample that the differential stress stays constants until pore pressure reaches about 250 psi. For all other samples, the differential stress decreases indicating the onset of failure due to pore pressure increase.

Other than the zero strain boundary condition sample (Fig. 3.32IV and 3.33IV) which has negligible strain, all the experiments in this section result in sample volume expansion due to pore pressure increase. The only exception is the sample at 1000 psi axial stress and 800 psi confining stress with constant axial stress and zero radial strain (Fig. 3.32II). Even though this sample did not dilate like the others, the compaction experienced is only 0.3% as compared to the ten times larger expansion experienced by the corresponding sample with higher confining stress & lower axial stress. A slightly different behavior is seen for samples ‘I’ and ‘III’ (Figure 3.33 and 3.34). Even though both samples of ‘I’ and ‘III’ dilated, the samples corresponding to higher axial stress dilated ten times more than the samples corresponding to higher confining stress.

Another way to examine the failure state of the sample is to plot the effective differential stress versus the effective mean stress (Fig. 3.34). As was seen in the previous plots in this section, the sample ‘I’ resists failure until the effective mean stress becomes much smaller (360 psi and 520 psi respectively for Fig. 3.34A and 3.34B). All the other samples follow decreasing differential stress path indicating failure of the sample due to pore pressure increase.
Figure 3.30: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 1000 psi initial axial stress and 400 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero axial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.31: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 400 psi initial axial stress and 1000 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero axial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.32: Maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 1000 psi initial axial stress and 400 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.33: Maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 400 psi initial axial stress and 1000 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.34: $q$-$p'$ plot for pore pressure increase experiments corresponding to IA, IIA, IIIA and IVA boundary conditions for A) 1000 psi initial axial stress and 400 psi initial confining stress B) 400 psi initial axial stress and 1000 psi initial confining stress.
3.2.3 Higher Mean Stress with Lower Initial Differential Stress

The third set of pore pressure increase experiments were performed with higher mean stress and lower initial differential stress. The initial stress condition was anisotropic. These experiments were performed for two cases, a) higher axial stress (Fig. 3.35, 3.37, 3.39A) b) higher confining stress (Fig. 3.36, 3.38, 3.39B). The values of initial stress used were 800 psi and 1200 psi. The samples can be considered to be oriented horizontally or vertically to fulfill the thrust faulting condition of Athabasca oil sands.

The loading history of the samples can be seen in Fig. 3.35 and 3.36 which shows the effect of pore pressure increase on the axial and confining stresses. For ‘I’ samples, the constant stresses remained at their initial values as the pore pressure was increased (Fig. 3.35I and 3.36I). However for the higher axial stress case (Fig. 3.35I), the axial stress changed when the pore pressure reached around 680 psi (which is much higher than the 250 psi seen in the last section). One other important difference with the last section is that the stresses remain almost constant for the higher confining stress sample (Fig. 3.36I). This can be attributed to the higher mean stress and lower differential stress of the later sample. For ‘II’ samples (Fig. 3.35II and 3.36II), the non-constant stress that is the confining stress does not start to change immediately (as opposed to changing immediately in the previous section). This can be attributed to the lower initial differential stress which keeps the failure state farther away at the beginning of the experiment. Similar behavior can be seen for ‘III’ and ‘IV’ samples where the change in stresses does not take place until a higher value of pore pressure is reached.

The deformation behavior can be interpreted further in the effective stress versus volumetric strain plots (Fig. 3.37 and 3.38). Other than ‘IV’ samples (zero strain boundary condition), all the samples in this section experience volume expansion. Similar to the previous section, the only exception is sample ‘II’ for higher axial stress. But,
unlike the previous section where the sample ‘II’ subjected to higher axial stress compacted significantly; the sample ‘II’ here showed volume increase. The one similarity between these two samples is the fact both of them show much less volume change.

The trend of differential stress can be observed from Fig. 3.37, 3.38 and 3.39. For sample ‘I’, the differential stress stays constant and starts to decrease when the pore pressure causes the effective mean stress to decrease substantially. The differential stress for samples ‘II’ and ‘III’ in Fig. 3.39A increases for a while and then decreases as the pore pressure was increased further. The decrease in differential stress indicates the onset of failure. All the four curves in Fig. 3.39A lie very close to each other after failure state has been reached. The samples ‘III’ and ‘IV’ in Fig. 3.39B show different behavior than the other curves. For these samples, the differential stress starts to decrease immediately and follows a different curve when failing.
Figure 3.35: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 1200 psi initial axial stress and 800 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero axial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.36: Axial stress, confining pressure ($P_c$) and pore pressure ($P_p$) versus time for 800 psi initial axial stress and 1200 psi initial confining stress

I) constant axial and confining stress
II) constant axial stress, zero radial strain
III) zero axial strain, constant confining stress
IV) zero axial strain, zero radial strain.
Figure 3.37: Maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 1200 psi initial axial stress and 800 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.38: Maximum effective principal stress, minimum effective principal stress, differential stress and pore pressure versus axial strain for 800 psi initial axial stress and 1200 psi initial confining stress I) constant axial and confining stress II) constant axial stress, zero radial strain III) zero radial strain, constant confining stress IV) zero axial strain, zero radial strain.
Figure 3.39: q-p’ plot for pore pressure increase experiments corresponding to IA, IIA, IIIA and IVA boundary conditions for 1200 psi initial axial stress and 800 psi initial confining stress B) 800 psi initial axial stress and 1200 psi initial confining stress.
3.2.4 Flow Properties

Flow properties were measured for the following cases (Fig. 3.40) for two different initial differential stresses. For a minimum principal stress of 400 psi, the other stress (axial or confining depending on the orientation of the sand pack) was set to be 1000 psi. For a minimum principal stress of 800 psi, the other stress was set to be 1200 psi. So, the 400 psi samples were much closer to the failure stress as compared to the 800 psi samples.

Three different loading scenarios were used with the above two different initial stress conditions. The different loading scenarios were designed to mimic the different reservoir and wellbore configurations expected in the field. In the earth there are three independent, orthogonal principal stress or strain directions, but with the cylindrical samples in the laboratory, there are only two independent directions (radial and axial). Consequently, each loading scenario can only partially reproduce the actual 3d aspects of the actual earth conditions. The sand sample can be considered to be either vertical or horizontal with respect to the reservoir conditions. For a vertical sample, the horizontal stresses would be equal while for a horizontal sample, the vertical stress and one of the horizontal stresses would be equal.
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<th>C: Higher Confining Stress</th>
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Figure 3.40: Schematic-grid for pore pressure increase stress path experiments.

The first loading scenario, consisting of zero lateral strain in both horizontal directions and constant vertical stress, is designed to represent a shallow reservoir with closely spaced SAGD well pairs (termed IIC in Fig. 3.40). Zero strain is assumed along the length of the horizontal wellbore because of its great extent compared to well spacing.
and the fact that conditions are assumed to be fairly constant in pressure and temperature along the axis of the lateral (the classic plane strain condition from solid mechanics). Zero strain is assumed in the other horizontal direction because of the proximity of nearby wells undergoing the same loading, preventing any net expansion or contraction. Since the reservoir is shallow, the earth’s surface can freely move up and down, providing no strain restriction in the vertical direction but instead constant stress (the overburden weighs the same no matter what the injection/temperature conditions in the reservoir). This loading scenario is achieved in the lab by orienting the sand core vertically, holding radial strain and axial stress constant during pore pressure loading.

The second loading scenario, consisting of constant stress in the vertical and one of the horizontal directions and zero strain in the other horizontal direction, is designed to represent a shallow reservoir populated sparsely by SAGD well pairs (termed IIB in Fig. 3.40). Similar to the IIC loading scenario, zero strain is assumed along the length of the horizontal wellbore and constant stress is assumed in the vertical overburden direction for the reasons outlined in the previous paragraph. Constant stress is assumed in the other horizontal direction because of the nearby wells being farther away and not playing a role in disturbing the constant horizontal earth stresses. This loading scenario is achieved in the lab by orienting the sand core horizontally, holding axial strain and radial stress (confining pressure) constant during pore pressure loading.

The third loading scenario, consisting of zero strain in the vertical and both horizontal directions, is designed to represent a deep reservoir with closely spaced SAGD well pairs (termed IVC in Fig. 3.40). Zero strain is assumed along the length of the horizontal wellbore and in the other horizontal direction because of the reasons outlined for IIC scenario. Since the reservoir is deep, the extent in the vertical direction is large and the pressure and temperatures are assumed to be fairly constant, the vertical boundary
condition can be considered to be a zero strain direction. This loading scenario is achieved in the lab by orienting the sand core horizontally, holding radial and axial strains constant during pore pressure loading.

All these boundary conditions (IIB, IIIC and IVB) used for the measurement of flow properties during pore pressure loading fulfill the thrust faulting stress regime condition in the Athabasca oil-sands reservoirs. As a result of pore pressure increase, the effective mean stress decreased causing dilation and increased volumetric strain except for samples ‘E’ and ‘F’ (Fig. 3.41a). Samples ‘A’ to ‘D’ underwent significant dilation while samples ‘E’ and ‘F’ which correspond to deep reservoirs did not undergo any dilation even though effective mean stress decreased. The volume increase for samples corresponding to shallow reservoirs (‘A’ to ‘D’) was between 3% and 5% as effective mean stress became close to zero. The samples corresponding to lower differential stress (and hence farther away from Mohr-Coulomb failure envelope) were able to sustain the differential stress until effective mean stress decreased to between 400-600 psi. The fall in differential stress represents failure of the sample. Two Mohr-Coulomb linear failure envelopes are drawn on Fig. 3.41b, both using a slope of $n=2.87$ but each having different UCS values of 0 psi and 134 psi (UCS=134 psi is the measured value shown in Fig. 3.4 for triaxial compression). Even for these unloading paths, the same equation appears to be valid and almost all the values (in Fig. 3.41b) fall in a narrow range.
Figure 3.41: a) (top) Effective mean stress versus volumetric strain and b) (bottom) Differential stress versus effective mean stress (q-p’ plot) as the pore pressure was increased for A) Constant axial stress, zero radial strain: axial stress of 400 psi and confining pressure of 1000 psi, B) Constant axial stress, zero radial strain: axial stress of 800 psi and confining pressure of 1200 psi, C) Zero axial strain, constant confining stress: axial stress of 1000 psi and confining pressure of 400 psi, D) Zero axial strain, constant confining stress: axial stress of 1200 psi and confining pressure of 800 psi, E) Zero axial strain, zero confining strain: axial stress of 1000 psi and confining pressure of 400 psi, F) Zero axial strain, zero confining strain: axial stress of 1200 psi and confining pressure of 800 psi. The stress values represent initial boundary conditions. Two Mohr Coulomb linear envelopes are drawn on the q-p’ plot to illustrate the failure state of the samples during pore pressure increase experiments.

3.2.4.1 Absolute Permeability Changes

The absolute permeability was measured by flowing through the sample at elevated pore pressures using the back pressure regulator. Between 0 and 40 psi pore pressure, the absolute permeability increased by about 80% but this effect is a manifestation of the initiation of flow. Since radial extension and increasing pore pressure are both unloading stress paths, it would be reasonable to expect similar permeability enhancement during pore pressure increase as well. But we only observed a modest increase of about 10% and that too when the pore pressure approached one of the confining stresses (except for experiment ‘D’ in Fig. 3.42). For experiment ‘D’, as the effective mean stress became zero, the absolute permeability increased rapidly and climbed to 2.2 times the initial permeability. This is unlikely to happen in a reservoir unless the reservoir is shallow and the pore pressure is high enough to part bedding planes. For experiments ‘E’ and ‘F’ corresponding to deep reservoirs, the absolute permeability remains the same throughout. The difference between radial extension and pore pressure increase experiments might be due to the difference in how the absolute permeability was measured. During pore pressure increase experiments, fluid pressure inside the sample was increased and absolute permeability was measured continuously.
This might not have allowed fluid flow to become steady. If this were indeed the case, we would expect steady state permeabilities to be higher since pressure drops for steady state flow would become lower.

![Normalized absolute permeability versus pore pressure](image)

Figure 3.42: Normalized absolute permeability versus pore pressure as pore pressure was increased for A) IIC, axial stress of 400 psi and confining pressure of 1000 psi B) IIC, axial stress of 800 psi and confining pressure of 1200 psi C) IIIB, axial stress of 1000 psi and confining pressure of 400 psi D) IIIB, axial stress of 1200 psi and confining pressure of 800 psi E) IVB, axial stress of 1000 psi and confining pressure of 400 psi F) IVB, axial stress of 1200 psi and confining pressure of 800 psi.

### 3.2.4.2 Relative Permeability Changes

The end point relative permeability to water and oil were measured during the pore pressure increase experiments at different pore pressures. The water saturated samples were subjected to the reference pore pressure (such as 100 psi), and oil flooded to the initial water saturation, and then water flooded to the residual oil saturation. The
measurements of end point $k_{ro}$ and $k_{rw}$ were made at initial water saturation and residual oil saturation respectively.

The $k_{rw}$ curves generally increased as the pore pressure was increased from 0 psi (Fig. 3.43). The increase ranged from 5% to 44% for the different boundary conditions and differential stresses. An increased effective permeability to water (inferred from increased relative permeability) would increase hydraulic conductivity and permit injection pore pressures to travel further into the reservoir (Chalaturnyk and Scott, 1997). Generally, the samples corresponding to deeper depths showed lower end point relative permeabilities. The $k_{ro}$ curves also showed an increasing trend for most of the cases (Fig. 3.44). For IIC 400-1000 psi sample, the permeability decreased by 2 percent; while for all the other samples, the end point relative permeability to oil increased from 2 to 45 percent. Increased oil permeability would result in an increased production rate.
Figure 3.43: End point relative permeability to water as the pore pressure was increased for A) IIC, axial stress of 400 psi and confining pressure of 1000 psi B) IIC, axial stress of 800 psi and confining pressure of 1200 psi C) IIIB, axial stress of 1000 psi and confining pressure of 400 psi D) IIIB, axial stress of 1200 psi and confining pressure of 800 psi E) IVB, axial stress of 1000 psi and confining pressure of 400 psi F) IVB, axial stress of 1200 psi and confining pressure of 800 psi.

Figure 3.44: End point relative permeability to oil as the pore pressure was increased for A) IIC, axial stress of 400 psi and confining pressure of 1000 psi B) IIC, axial stress of 800 psi and confining pressure of 1200 psi C) IIIB, axial stress of 1000 psi and confining pressure of 400 psi D) IIIB, axial stress of 1200 psi and confining pressure of 800 psi E) IVB, axial stress of 1000 psi and confining pressure of 400 psi F) IVB, axial stress of 1200 psi and confining pressure of 800 psi.

3.2.4.3 Initial Water Saturation

The initial water saturation was measured as the pore pressure was increased. The initial water saturation ranged between 7 and 16 percent at zero pore pressure. As seen in Fig. 3.45, the initial water saturation generally increases except for curves E and F, which correspond to the zero axial and radial strain boundary conditions. The initial water saturation at the end of the pore pressure increase experiments ranged between 11 and 27 percent.
percent. The samples A to D dilated during pore pressure increase. As the samples dilated, the pore throat and pore body sizes increased causing more water to line up the surface of the sand grains.

Figure 3.45: Initial water saturation as the pore pressure was increased for A) IIC, axial stress of 400 psi and confining pressure of 1000 psi B) IIC, axial stress of 800 psi and confining pressure of 1200 psi C) IIIB, axial stress of 1000 psi and confining pressure of 400 psi D) IIIB, axial stress of 1200 psi and confining pressure of 800 psi E) IVB, axial stress of 1000 psi and confining pressure of 400 psi F) IVB, axial stress of 1200 psi and confining pressure of 800 psi.

3.2.4.4 Residual Oil Saturation

The residual oil saturation at zero pore pressure ranged from 16 to 30 percent. It decreased for samples A, B, C and D (Fig. 3.46) by 45, 63, 44 and 39 percent, while it stayed essentially constant for E and increased by 11% for sample F. As seen in the previous sections, the samples A, B, C and D dilated while pore pressure was increased. As the samples dilated, the rearrangement of the grains provided better pore connectivity.
which lowered the residual oil saturation. The samples E and F did not dilate due to the imposed zero strain boundary conditions, which would correspond to a deep oil sands reservoir. This is consistent with observations from triaxial compression experiments, where the sample at 800 psi confining pressure experienced negligible dilation.

Figure 3.46: Residual oil saturation as the pore pressure was increased for A) IIC, axial stress of 400 psi and confining pressure of 1000 psi B) IIC, axial stress of 800 psi and confining pressure of 1200 psi C) IIIB, axial stress of 1000 psi and confining pressure of 400 psi D) IIIB, axial stress of 1200 psi and confining pressure of 800 psi E) IVB, axial stress of 1000 psi and confining pressure of 400 psi F) IVB, axial stress of 1200 psi and confining pressure of 800 psi.
3.3 **Isotropic Compression**

Three Athabasca sand samples were isotropically compressed to study the effect of over-consolidation on the permeability. The samples were subjected to 3000 psi of isotropic stress resulting in 30 to 38 percent volumetric strain (Fig. 3.47). The initial permeability ranged from 7 to 10 Darcies and got reduced to about 4 Darcies. The most decrease occurred during the first 100 psi of compaction, and a compaction of 3000 psi reduced the permeability by 40 to 50 percent (Fig. 3.48). This is due to the rearrangement of grains into a tighter matrix. The permeability does not return to its original value even when the stress state is restored.

![Figure 3.47: Mean stress vs. volumetric strain as the stresses are increased isotropically.](image)

Figure 3.47: Mean stress vs. volumetric strain as the stresses are increased isotropically.
Figure 3.48: Normalized absolute permeability versus mean stress as the stresses are increased isotropically.
Chapter 4
Summary and Conclusion

Laboratory experiments were performed on reconstituted bitumen-free Athabasca oil sands samples to study the deformation and flow properties during different stress paths. These stress paths are very similar to the stress paths encountered during a steam injection process in unconsolidated sands, such as SAGD in Athabasca oil sands.

Triaxial compression experiments were performed at 100, 200, 400 and 800 psi effective confining pressures. The Young’s modulus and friction angles for the Athabasca sand samples in this study are similar to earlier studies (Fig. 3.4). For 100, 200 and 400 psi confining pressure samples, the volumetric strain remained compactive for about 2% axial strain, and reached between -1% and -3% volumetric strains. These volumetric strains are indicative of dilation and formation of shear bands. The sample at 800 psi confining pressure underwent compaction and negligible dilation, and reached +1% volumetric strain. This suggests that the dilative behavior is much more pronounced for oil sands reservoirs near the surface and the dilative behavior diminishes as the reservoir becomes deeper. This is evident in the permeability results as well. The absolute permeability for samples at 100, 200, 400 psi confining pressures increased by 20%, while the permeability decreased by 10% for the 800 psi sample. There was some evidence for post-deformation fines generation for the 800 psi sample. End-point $k_{rw}$ decreased during compaction, and increased by 40% compared to the compacted values for low confining pressure samples; while it decreased a further 25% for the 800 psi sample. Similarly, end-point $k_{ro}$ decreased during compaction and increased by 15% for low confining pressure samples; while it decreased a further 5% for the 800 psi sample. The residual oil saturation decreased by as much as 40% for the low confining pressure
samples, after the initial increase during compaction. The 800 psi sample’s residual oil saturation continued to increase throughout the experiment.

Radial extension experiments were performed at initial effective confining pressures of 500, 1000 and 1500 psi. The samples started dilating immediately, and dilated up to 12% which is much higher than the dilation observed during triaxial compression experiments. The permeability enhancement for the 500 psi confining pressure sample was the largest (50%), while it was the smallest (20%) for 1500 psi sample. End-point $k_{rw}$ and $k_{ro}$ increased by as much as 60% and 20% respectively. The residual oil saturation decreased by up to 55%.

Pore pressure increase deformation experiments were conducted for 12 different boundary conditions (Figure 3.22) and two different differential stress conditions. Subsequent to these experiments, pore pressure increase experiments were conducted for 3 boundary conditions, and two different differential stress conditions. These boundary conditions were selected to represent different reservoir conditions. The following discussion pertains to these six pore pressure increase experiments, for which flow properties were also measured. If a constant stress direction is present (that is, for IIC and IIIB), the stress in the zero strain direction started decreasing immediately for the lower initial differential stress, as compared to decreasing once the pore pressure reached a certain value. This would decrease the compressibility of the sand matrix in that direction and increase porosity. The amount of dilation was almost similar for both cases of differential stress, for a particular boundary condition. The differential stress supported by the samples started to decrease, regardless of the initial differential stress or the boundary conditions, when the effective mean stress reached 600 psi or a lower value. The peak differential stress is a failure state (Darve et al., 2003).
If a constant stress direction is present (that is, for IIC and IIIB), the absolute permeability increased by about 80% during the initial pore pressure increase up to 40 psi (which can attributed to flow turbulence) and settled on a uniform increase of about 0-10% as the pore pressure was further increased. As the pore pressure reached close to the initial effective confining stress, the absolute permeability increased by about 130% (the flow during experiments IIC were stopped as soon as the pore pressure reached one of the confining stress values; it is expected that had this flow been continued, the absolute permeability would increase much further. The trend towards the end is of increasing permeability like in the IIIB experiments). The absolute permeability for the plane strain boundary condition samples (corresponding to a deep oil sands reservoir) did not increase at all. The reason can be attributed to plane strain boundary condition. As the pore pressure increased beyond a certain value, the stress in the confining direction increased as well. When the pore pressure reached the initial confining stress, the confining stress had already moved to a higher value. The generally suppressed values of absolute permeability may have been due to steady state flow not being reached during continuous measurement of fluid flow through the sample at elevated pore pressures.

The end-point relative permeability to water and oil increased by 5-44% and 2-45% respectively during the pore pressure increase experiments. The samples corresponding to deeper depths showed lower end point relative permeabilities. The initial water saturation, increased for samples with one constant stress boundary condition; while it decreased for sample with both plane strain boundary conditions. The residual oil saturation, decreased (40% to 60%) for samples with one constant stress boundary condition; while it increased (0% to 10%) for samples with both plane strain boundary conditions. This suggested that for deeper reservoirs, the pore pressure increase
may not result in favorable saturation changes. The end-point relative permeability to water and oil increased regardless of the depth.

The isotropic compression experiments showed that during ice loading of Athabasca oil-sands, the loss of permeability (for depths corresponding to 3000 psi stress) would be about 40% to 50%.

4.1 FIELD APPLICATIONS

During the SAGD process in shallow, unconsolidated reservoirs the horizontal stresses may increase due to the thermal stresses generated by the elevated temperatures. A decrease in the overburden stress would occur due to the increase in pore pressure. The increase in the horizontal stresses may be more than the decrease in the vertical stress, resulting in a stress path similar to triaxial compression. The triaxial compression follows a path of increasing mean stress. During the compaction phase, the relative permeability decreases and residual oil saturation increases, resulting in lower recovery factors from the reservoir. However, the compaction phase is followed by a dilation phase in which the relative permeability increases and residual oil saturation decreases, resulting in higher recovery factors. During the triaxial compression experiments, the end-point relative permeability to water and oil increased by 40% and 15% (compared to the compacted values) respectively for the samples corresponding to lower depths. Similarly, the residual oil saturation decreased by as much as 40% for the samples corresponding to lower depths. However, the post-compaction dilative behavior diminishes with depth. At depths corresponding to 800 psi, there was negligible sample dilation and continued decrease in relative permeability and increase in residual oil saturation. At greater depths, there might be some grain crushing and generation of fines as well.
Steam injection increases the pore pressure in the reservoir and causes the mean stress to decrease. Both radial extension and pore pressure increase experiments follow paths of decreasing mean stress. The dilation during the radial extension experiments (up to 12% volumetric strain increase) was greater than the dilation observed in triaxial compression experiments. The permeability enhancement decreased with depth and ranged from 20% to 50%. The residual oil saturation decreased by up to 55%, which would improve the recovery from the reservoir.

The pore pressure increase experiments showed enhanced recovery for shallow reservoirs. The increase in absolute permeability was about 0-10% when the pore pressure was low, while it increased to about 130% when the pore pressure reached the value of one of the confining stresses. This suggests that a higher pore pressure which is close to the initial mean effective confining stress would lead to enhanced absolute permeability (Chalaturnyk and Li, 2004). However, the sample corresponding to a deep reservoir (plane strain boundary conditions) did not show increased absolute permeability when the pore pressure approached the initial confining stress. The residual oil saturation decreased (40% to 60%) for samples corresponding to shallow depths while it increased (0% to 10%) for samples corresponding to greater depths. This suggests that for deeper reservoirs, the pore pressure increase may not result in favorable saturation changes. The reservoirs with high differential stress are more conducive to favorable changes in permeability and residual oil saturation since the formation is already on its way to the failure envelope. These reservoirs will require a lower injection pressure to fail.

These results suggest that a decreasing mean stress path is more beneficial for production increase than an increasing mean stress path. A high pore pressure close to the initial mean effective confining stress results in a higher absolute permeability. An increased relative permeability to water would increase hydraulic conductivity and permit
injection pore pressures to travel further into the reservoir, while an increased relative permeability to oil would result in increased production rates and lower steam/oil ratios. This means that the steam chamber would occupy a larger area within the reservoir in a shorter time. The permeability increase and residual oil saturation decrease due to dilation diminishes with the depth of the reservoir, so the advantage in increased production rate due to dilation would be less at increasing depths.

4.2 FUTURE RESEARCH AND RECOMMENDATIONS

True triaxial experiments would be informative. This would allow changing all three stresses and studying the different well-pair configurations in a cubic box, leading to more realistic depiction of the reservoir. Layers can be incorporated in the sand sample to study the effects of bedding layers and lithology on the steam chamber growth and production rates. A study can be done using electric heaters in the box to investigate the effect of temperature on the SAGD process.

A study using steam may be performed with samples saturated with bitumen or heavy-oil, so that a better understanding of multiphase, elevated temperature flow through the reservoir is developed. This can be undertaken with the current experimental setup with minor modifications and the addition of a steam generator.

Future studies can be conducted on assessing the wettability of extra-heavy oil and bitumen rocks; and using different chemical agents to change this wettability to increase the recovery and production rates. After a few favorable chemicals have been identified, deformation experiments can be performed and the utility of the chemicals assessed when used as an additive in steam or water injection.

A coupled geomechanical numerical study may be performed which uses the results from this study to build and history-match a reservoir rock model. This model can
be used to perform virtual geomechanics and flow experiments and more robust predictions can be made regarding similar reservoirs.

Absolute and relative permeability was measured in the axial direction only, which is the direction of the most compressive stress in the experiment. Experiments may be performed using a new setup, which would allow measurement of horizontal permeability as well. The changes in horizontal permeability with stress might be different due to the angular shape of the grains.

A study can be performed using a CT (computed tomography) scanner to investigate the saturation changes in the samples with stress changes. This would allow a real-time study of the formation of shear bands and how they affect the flow in the reservoir. An accurate account of the sweep and bypassed areas in the samples can be made and different methods used to improve the mobility ratios.
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