The Thesis committee for Stephen Albert Hester III

Certifies that this is the approved version of the following thesis:

Engineering and Economics of Enhanced Oil Recovery in the Canadian Oil Sands

APPROVED BY

SUPERVISING COMMITTEE:

Supervisor: ______________________________
William L. Fisher

____
J. Eric Bickel

____
Larry W. Lake

Engineering and Economics of Enhanced Oil Recovery in the Canadian Oil Sands

by

Stephen Albert Hester III, B.A.

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Dedication

This thesis is dedicated to my mother, father, and brother.

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Abstract

Engineering and Economics of Enhanced Oil Recovery in the Canadian Oil Sands

by

Stephen Albert Hester III, MSEER

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SUPERVISOR: William L. Fisher

Canada and Venezuela contain massive unconventional oil deposits accounting for over two thirds of newly discovered proven oil reserves since 2002. Canada, primarily in northern Alberta province, has between 1.75 and 1.84 trillion barrels of hydrocarbon resources that as of 2013 are obtained approximately equally through surface extraction or enhanced oil recovery (EOR) (World Energy Council, 2010). Due to their depth and viscosity, thermal based EOR will increasingly be responsible for producing the vast quantities of bitumen residing in Canada's Athabasca, Cold Lake, and Peace River formations. Although the internationally accepted 174-180 billion barrels recoverable ranks Canada third globally in oil reserves, it represents only a 9-10% average recovery factor of its very high viscosity deposits (World Energy Council, 2010).

As thermal techniques are refined and improved, in conjunction with methods under development and integrating elements of existing but currently separate processes, engineers and geoscientists aim to improve recovery rates and add tens of billions of barrels of oil to Canada's reserves (Cenovus Energy, 2013). The Government of Canada

estimates 315 billion barrels recoverable with the right combination of technological improvements and sustained high oil prices (Government of Canada, 2013). Much uncertainty and skepticism surrounds how this 75% increase is to be accomplished. This document entails a thorough analysis of standard and advanced EOR techniques and their potential incremental impact in Canada's bitumen deposits. Due to the extraordinary volume of hydrocarbon resources in Canada, a small percentage growth in ultimate recovery satisfies years of increased petroleum demand from the developing world, affects the geopolitics within North America and between it and the rest of the world, and provides material benefits to project economics.

This paper details the enhanced oil recovery methods used in the oil sands deposits while exploring new developments and their potential technical and economic effect. CMG Stars reservoir simulation is leveraged to test both the feasible recoveries of and validate the physics behind select advanced techniques. These technological and operational improvements are aggregated and an assessment produced on Canada's total recoverable petroleum reserves. Canada has, by far, the largest bitumen recovery operation in the world (World Energy Council, 2010). Due to its resource base and political environment, the nation is likely to continue as the focus point for new developments in thermal EOR. Reservoir characteristics and project analysis are thus framed using Canada and its reserves.

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Chapter 1

Introduction: Purpose and Scope of Thesis

Canadian oil reserves are estimated at 180 billion barrels using existing recovery technologies (Government of Alberta, 2013). In the context of North America, assuming 2011 United States (U.S.) production levels of nine million barrels (bbls) per day, Canada could conceivably supply all U.S. import demand for the next fifty five years. In spite of declining net oil imports, the United States' net consumption of Canadian oil increased from 22% of oil imports in 2008 to 30% in 2012 (U.S. Energy Information Administration, 2013). Canada's Alberta province alone contains sufficient recoverable oil to put the nation at number three in oil reserves worldwide (Government of Alberta, 2013). Two thirds of the global increase in proven reserves in the last 15 years is due Canada's oil sands and Venezuela's Orinoco Heavy Oil Belt. Unlike conventional crudes of other major producers such as Saudi Arabia and Russia, 98% of Canada's reserves are extremely high viscosity and cannot be produced through orthodox means (Government of Canada, 2013).

Instead, producers rely on surface mining and a variety of enhanced oil recovery (EOR) methods. EOR techniques range from a single vertical well coupled with steam injection to designs incorporating multiple lateral wells injecting steam with designer chemicals or solvents. These advanced processes test the limits of our understanding of physics, geology, and engineering (Government of Alberta, 2013). The efficiency existing technologies achieve as well as what impact new technologies have on heavy and extra heavy oil deposits has a material impact on global proven reserves. This document discusses these challenges and how system design and implementation affects not only individual project results but their cumulative impact on global production rates. Special attention is paid to the strengths and weaknesses of each thermal method given the criticality of process selection and strategy to recovery rates and successful project economics. The apt intersection of commodity prices, efficiency gains, and new technologies are bringing reservoirs previously determined unprofitable online. Foreseeable developments and their impact on production rates and economics are covered including analysis on how new methodologies might affect producible hydrocarbons in Canada. Ascertaining this figure depends heavily on the effectiveness and adaptability of processes currently under development. Society of Petroleum Engineers publications, the quarterly earnings and accounting figures of major firms involved, and industry wide technical presentations are augmented by reservoir simulation through CMG-Stars to estimate the financial and technical implications of advanced EOR. The structure of this paper is as follows:

- Chapter 1 provides an introduction including the purpose and scope of the document.
- Chapter 2 covers relevant classifications and key characteristics of heavier crude oils. In addition to the fundamental geology of the Athabasca Oil Sands, its hydrocarbon reserves and production are put into context globally. The distribution of resources applicable to surface extraction and mining are discussed alongside their associated recovery processes.
- Chapter 3 contains information on chemical and solvent based enhanced oil recovery applications. Polymer, Alkaline, Surfactant methodologies are detailed including economics, recovery rates and mechanisms, as well as project analysis of those implemented in the region. Gas injection of several solvents is also discussed.
- Chapter 4 summarizes thermal recovery and its challenges while going into significant detail concerning simple and advanced thermal processes. Baseline project economics are primarily derived from recent Society of Petroleum Engineers' literature and quarterly earnings reports filed with the Securities and Exchange Commission by active firms in the region such as Cenovus Energy and EnCana Energy.

- Chapter 5 focuses on the physics and engineering behind developing and more complex methods at recovering viscous oils. The unique recovery mechanisms and potential recovery factors of hybrid applications involving thermal, chemical, and or gas injection methods are conferred. The results of reservoir simulations using CMG-Stars are included and evaluated. Preliminary findings from simulations coincide with theoretical benefits of combined, multi-phase processes and are generally consistent with the literature surveyed.
- Chapter 6 discusses the unique thermodynamic, engineering, and operational challenges associated with enhanced oil recovery in the oil sands. Special attention is paid to viscosity reduction, thermal efficiency, and operational improvements aimed at reducing heat losses and or increasing recovery. Steam generation, an integral operational component, is achievable through various means and their costs and benefits are included. Process selection criteria and testing regimes are incorporated here.
- Chapter 7 estimates the aggregate value of enhanced oil recovery, future corresponding production rates at given crude prices, and details the economic impact oil sands development is having across Canada. Environmental challenges, which are directly related to the pace and ease of development in the region, are also discussed.
- Chapter 8 concludes with a macroeconomic analysis of enhanced oil recovery's future potential and provides a range of ultimate recovery rates taking into consideration the numerous existing and developing recovery methods alongside their probable recovery rates and applicability. Today's estimated 180 billion barrels producible from the Canadian Oil Sands increases to 230-262 billion barrels depending on factors reviewed therein.

Chapter 2

Reservoir Characteristics

2.1 Bitumen and Heavy Oil Classifications

Canada's oil sands consist of natural bitumen categorized by API gravity below 10° and viscosity higher than 10,000 centipoise (cP). Athabasca bitumen at reservoir conditions is approximately 1,700,000 cP. Bitumen has higher concentrations of heavy metals, sulfur, oxygen, and nitrogen than conventional crude oil. These properties correspond with more expensive production, refining, and transportation. Heavy and Extra Heavy Oil, as most of Venezuela's reserves are characterized, are similar to bitumen but have a maximum viscosity of 10,000 cP due to less bacterial degradation (World Energy Council, 2013). Despite this, high energy prices and vast improvements in extraction technology and economics have caused billions in bitumen project investment in the last 10 years (Government of Alberta, 2013). In its infancy stage compared to conventional crude's 150 year production history, new extraction technologies continually redefine expectations of heavy oil and bitumen reserves and their impact on the oil industry, global trade, geopolitics, and the environment. This paper seeks to incorporate the latest production techniques for this type of reserves against the available data on Canada's known reservoir geology, oil characteristics, production histories, and estimated hydrocarbon reserves. Using these findings in combination with CMG-Stars reservoir simulator testing, probable reserves under varying conditions are found and their impact discussed.

2.2 Geology of the Oil Sands

In order to understand the distribution, formation, and common reservoir characteristics of Canada's bitumen reserves, a basic geological analysis is required.

These resources are degraded remains of massive conventional oils, primarily by bacteria. The exact source rock for each formation is not precisely identified but geomechanical, petrophysical, and oil analysis reveal strong correlations. Produced oil has sulfur contents of 1.2-1.7% weight in Athabasca coinciding with the high sulfur content found in the Exchaw and Gordondale source rock derived oils. The Duvernay, Upper Cretaceous, and Triassic sourced oils consistently contain less than 1% weight sulfur. Nitrogen and Vanadium percent weights confirm bitumen is likely from the Exchaw and Gordondale formations while high API reserves, such as those in western Peace River, are Duvernay derived (Adams & Marcano, 2010). These source rocks are among the largest in the world. A stratigraphical unit of Frasnian age located in the Western Canadian Basin, the Duvernay source rock is estimated by Canada's Resources Conservation Board to contain "443 trillion cubic feet of gas and 61.7 billion barrels of oil" (Penty, 2012).

The enhanced oil recovery technologies covered in this thesis are applied to a multitude of reservoir and oil types. Canada's vast bitumen reserves are best suited to thermal techniques implemented in three classes of reservoirs; medium heavy oil, extra heavy oil, and lastly tar sands and bitumen. Average corresponding downhole viscosities are 10-100, 100-10,000, and 10,000 to 10,000,000 cP respectively. A fourth class consists of oil shale but with no permeability it is extracted through mining only. Canada's reserves fall into the third category while Venezuela's Orinoco belt resides in the second class (World Energy Council, 2013). Medium heavy oils are often extracted through steam drive alone while heavier oils and tar sands may require Cyclic Steam Stimulation (CSS), Steam Assisted Gravity Drain (SAGD), and other more evasive and intricate procedures (World Energy Council, 2013).

2.3 Resource Distribution

With an estimated 70% of known natural bitumen reserves, Canada is the largest global player and the focus of this paper. Its resources are concentrated in the Alberta province in the Peace River, Athabasca, and Cold Lake formations (World Energy Council, 2013). Original oil in place (OOIP) is estimated at 1,339 billion barrels in Athabasca, 201 billion in Cold Lake, and 155 billion in Peace River. The frequently referenced economically producible 180 billion barrels represents a 10% recovery rate though not all areas are exploitable in a cost effective manner due to variables such as pay zones less than 15 meters (m) thick. Due to variances in geological assessments and the depth surface mining remains economical, estimates of in situ versus mining reserves range considerably. The government of Alberta states 80% of reserves are too far below the earth's surface for mining and require in situ activities (Government of Alberta, 2013). Canadian Natural Resources, on the other hand, believes only 7% of Canada's oil sands are recoverable through mining (Canadian Natural Resources, 2013). This document outlines technologies and operational approaches that can reasonably raise ultimate recovery rates closer to 20%; putting Canada on par with Venezuela's world leading 300 billion barrels of reserves and in the realm of Canada's own high end energy assessments (Government of Canada, 2013). Each major region's reserves are included in the analysis for total recovery potential using mining, standard EOR applications, as well as those under development.

Before exploring the methodologies, it's important to note the impact the distribution between surface mining and in situ techniques has on resource development. While current production is 51% mining and 49% in-situ, approximately 12.6-33.6 billion barrels are recoverable through mining while 135.1-167.4 billion require thermal applications (Government of Alberta, 2013; Canadian Natural Resources, 2013). A massive shift toward steam and combustion processes must take place over time in line with reserve supplies. Benefits to this trend are in situ projects' quicker return on capital, reduced project lengths, and high recovery efficiency versus surface extraction. The heavy weighting toward in-situ projects allows technological adaptations the potential to increase total Canadian output significantly. An additional 5% of Canada's in-situ categorized bitumen becoming recoverable is worth approximately 60 billion incremental barrels. Stated differently, if the 10.3% historical recovery rate increases to 12.9% due to technological advancements, total Canadian production grows by over 25%. Recovering 15% of bitumen resources causes Canada to surpass Saudi Arabia's ranking in reserves. Oil sands were included in official reserves only recently in the oil industry's history; they now represent over 5 million bbls/d of production and between one and two thirds of global oil reserves depending on the source (World Energy Council, 2013). As the major shift from mining to in-situ gradually takes place, the energy sector has time to improve processes and experiment with new methodologies.

2.3.1 Surface Mining

Regarding the half of current production using surface extraction, only Alberta's Athabasca formation is suitable for wide scale mining; at least 80% of the province's oil is recoverable solely through in situ techniques (National Energy Board of Canada, 2008). Suncor's Great Canadian Oil Sands mine, North America's largest, began operation in 1967 and is focused in Athabasca. As the first commercial venture in the Canadian oil sands it claimed per barrel of synthetic crude production costs of $27 in 2008, despite significant increases in energy and labor costs. Four mines, the original Suncor operation, Syncrude's 1978 mine, Shell Canada's Muskeg River project initiated in 2003, and Canadian Natural Resources mine online as of 2009 are active. Several additional mines, such as Jackpine, Imperial Oil's Kearl Oil Sands Project, Synenco Energy's Northern Lights, and Suncor's Fort Hills mine are in development or nearing completion. As insight into costs, Royal Dutch Shell announced a profit of $21.75/bbl of Bitumen compared to $12.41/bbl of conventional oil in 2007. Canadian Natural Resources spent $9.7 billion on total construction and startup costs for their recent Horizon Oil Sands project or $88,182 per flowing bbl capacity. Including project amortization and operating expenses, per bbl cost is stated to range between $25 and $35 for the project's life time. The synthetic crude is a favorable 34° API with low sulfur content (Canadian Natural Resources, 2013). This suggests the costs of mining and refining bitumen are often competitive against conventional production (Shell, 2008).

Oil sands development began with surface extraction and this process will remain a major component of activity in the region for at least the next ten years. Large hydraulic cranes and the world's largest dump trucks, with capacities nearing 400 tons, remove thousands of tons of bitumen daily. Hot water and Sodium hydroxide (NaOH) are added to the sand once extracted. The slurry is piped to a processing plant where agitation separates the oil which is skimmed from the top. The oil is further treated to remove residual water and fine solids through separation vessels (Government of Alberta, 2009). Two tons of bitumen produce one barrel of oil; the remaining 15/16ths of material is returned to the mine and eventually reclaimed (Canadian Oil Sands Trust, 2007).

2.3.2 In-Situ Extraction

The methodologies outside of surface extraction fall under the broader category of enhanced oil recovery. Due to the wide-ranging and increasing spectrum of EOR applications, no precise definition exists although it is understood as processes after primary and secondary recoveries are exhausted. Oil and tar sands, with viscosities exceeding 1,000,000 cP, are generally unsuitable for conventional production methods (World Energy Council, 2013). An EOR method is likely the first used when the reservoir is too deep for mining. Cold Heavy Oil Production with Sand (CHOPS) applied in the Orinoco fields of Venezuela is a simpler and less capital intensive mechanism than the steam based methods commonly used in Canada although with poorer recovery rates. CHOPS is unsuitable for most oil sands due to their higher viscosity disallowing measurable flow under reservoir conditions (World Energy Council, 2013).

In conventional reservoirs, primary and secondary processes recover 5-35% of OOIP depending on reservoir heterogeneity, oil type, and other characteristics. EOR aims for an additional 5-65% with total recovery in ideal circumstances exceeding 80% of OOIP. Project design is often several times more complex and capital intensive than standard methods, necessitating a greater understanding of reservoir properties, precise well placement, and more comprehensive project and reservoir management.

Chapter 3

Chemical and Solvent Applications

While thermal applications are and likely will continue to be the primary mechanism to produce Canadian bitumen, other EOR methods are used in conjunction with thermal and occasionally independently. EOR is generally divided between solvent, chemical, and thermal strategies. Thermal processes in conjunction with chemical and or solvent injection are gaining popularity. The diversity and potential integration of EOR processes is critical toward maximizing a project's potential. Cenovus's SAP technology, combining solvent injection and Steam Assisted Gravity Drainage (SAGD) for improved recovery, is a commercially successful example of utilizing multiple EOR methods simultaneously (Energy, 2013). Given the pace and variety of developments, it is probable that within a reservoir's lifetime new technologies will become available to improve recovery rates and or reduce costs. Canadian Natural Resources recently mentioned evaluating polymer flooding and solvent injection with their existing thermal applications in heavy oil in attempt to raise recoveries above the average 15% of OOIP they are achieving (Canadian Natural Resources, 2013).

3.1 Solvent Applications

Gas injection methods are presently implemented independently of, such as Vaporized Extraction (VAPEX), and in conjunction with thermal applications in the Canadian oil sands. They are also leveraged in many of Canada's conventional deposits although on an aggregate basis they are a small fraction of Canada's overall oil reserves (Government of Alberta, 2013). The U.S. Department of Energy (DOE) estimates 55-60% of EOR production domestically is from gas injection (Department of Energy, 2013). These methods impact oil differently than steam while carrying lower operating costs. Gas injection can increase the sweep efficiency of standard water floods and alter oil characteristics toward a more mobile state.

3.1.1 Reservoir and Oil Suitability

Used independently, solvent injections are generally economically effective against oil between 18° and 30° API and medium to low viscosities. Carbon dioxide based EOR has been applied successfully in West Texas's Permian Basin for several decades. An estimated 245,000 bbls per day is now produced from CO_2 EOR in the U.S. and production levels above 100,000 bbls per day have been maintained over the past twenty years (American Petroleum Institute, 2005). Cumulative incremental production exceeds 1 billion bbls in the U.S. with the Department of Energy's 2009 report estimating a maximum potential recovery domestically of 84.8 billion bbls provided "costs, oil price and risks justify investment" (National Energy Technology Labratory, 2010). This report is a more geological and technical assessment than commercial one; only the Permian Basin in west Texas currently has the infrastructure, reservoir data, commercial investment, and other variables on a scale sufficient to reach the DOE's targets. This area alone, however, has an estimated 15 billion barrels of recoverable oil through CO_2 injection (National Energy Technology Labratory, 2010).

3.1.2 Miscibility

Immiscible injection benefits from low pressure requirements, inexpensive inputs, and recovery rates of 5-10% incremental oil recovery. Miscible displacement requires 1,200-5,000 pounds per square inch (psi) depending on application but decreases oil viscosity due to oil swelling and raises average recovery to 15% incremental oil recovery (IOR) (American Petroleum Institute, 2005). Miscible displacement can also improve rock wettability as a supplementary recovery mechanism (National Energy Technology Labratory, 2010). Viscous fingering and gas loss through trapping or leakage can significantly lower cost efficiency and be difficult to predict or avoid once encountered. Identifying fractures within the reservoir is especially critical; their existence is not always evident during the primary and secondary stages of production. Water flooding does not affect the same areas of a reservoir as gas because its in-situ flow and interaction with gravity differ. The difficulty of maintaining a favorable solvent to oil mobility ratio increases with oil viscosity and leads to poor sweep efficiency and viscous fingering (American Petroleum Institute, 2005).

3.1.4 Nitrogen, Natural Gas, and Carbon Dioxide

Obtaining consistent and large volumes of injection gas can be problematic and often dictate project economics more than any other variable. Although nitrogen, methane, alcohols, and flue gas are options under certain circumstances, carbon dioxide benefits from low levels of corrosion, miscibility at comparatively lower pressures, and plentiful industrial and natural sources in many regions. Operators in the Permian Basin in west Texas, the region carbon dioxide EOR is most prolific, injects CO_2 primarily from local underground sources. Many fields in Alaska use similar processes and inject produced natural gas to improve sweep efficiency as no infrastructure exists to transport it to market. Utilizing natural sources of CO_2 is common among projects, especially in remote areas, due to inadequate integration with utility and heavy industries responsible for most localized and long term CO_2 production. The Jackson Dome formation supplies most gas used in CO_2 injection projects in the Gulf of Mexico despite this area being one of the world's largest refining hubs (National Energy Technology Labratory, 2010).

3.1.5 System and Operational Design

Solvent methods are further optimized by strategically layering the injection process with water flooding. Water Alternating Gas (WAG) processes are responsible for over 90% of all CO_2 EOR projects in the Permian Basin, Colorado, Oklahoma, and Wyoming (Merchant, 2010). Other types are Gravity-Stabilized recovery, Double Displacement, and Gas-cycle. Reservoir geology and well pattern configuration common to the Permian Basin are ideal for WAG. Formations are generally flat with low permeability and developed on pattern spacing, such as a 5-spot well pattern. Engineers balance CO_2 volumes against incremental recovery and typically inject 30-40% hydrocarbon pore volume (HCPV) when using WAG in the Permian Basin (Merchant, 2010). Gravity-stabilized and Double Displacement inject nitrogen, flue gas, or CO_2 into the top of the reservoir and attempt to produce oil from the bottom. Although reservoir structure and certain fluid-dynamic properties must be met, these unconventional techniques allow up to 80% of total pore volume to be displaced by the injected gas, a significant improvement over standard WAG processes (Reserves, 2007). Gas-cycling cycles CO_2 through a formation for 15-20% OOIP while Huff-and-Puff operations utilize a simpler design of a single well responsible for injecting solvent and producing oil. The latter structure mirrors the thermal method of Cyclic Steam Stimulation used in heavy oil deposits (Merchant, 2010). The National Energy Technology Lab estimates an average profit of $15 per barrel at $70 bbl oil using solvent injection. Profit varies considerably depending on infrastructure and CO_2 costs (National Energy Technology Labratory, 2010). Numerous firms are testing and implementing the combination of these methods with steam injection. Given thermal is up to several times more expensive and energy intensive per barrel of oil than the aforementioned processes, strong incentives exist to incorporate non thermal components for cost savings and improved recovery. Several strategies' economics and recovery mechanisms are detailed in the hybrid thermal section.

Besides the complexity of primary and secondary stages of oil production, gas EOR has additional layers of costs and engineering challenges. Identifying the optimal gas injection rate and monitoring for problems is a demanding, ongoing process. For miscible solvent injection, identifying reservoir pressure and integrity, as well as oil API is critical. The miscibility process can be complex and under some conditions multi-contact miscible (American Petroleum Institute, 2005). Initially, oil and gas are not miscible but light components from the oil begin transitioning to the gas phase. Heavy, long-chain hydrocarbons from the gas enter the liquid phase and contact new oil. Eventually, miscibility forms as the gas and oil reach the correct compositions (Schlumberger, 2011). CO_2 is usually transported at approximately 1,200 psi through pipelines unsuitable for natural gas derivatives or fluids. At costs of $16,000 to $43,000 per inch/mile, substantial long term investments are necessary since the pipelines are unlikely to have any use besides transporting CO_2 to oil wells (Carbon Capture and Sequestration Trechnologies Program, 2009). Risk management makes agreements with power plants or other non-natural sources difficult. If environmental regulations change abruptly or a power plant's output of CO_2 decreased significantly, millions of dollars in pipeline and well developments are jeopardized. Power plants, however, have similar 25-50 year productive timespans as many oil reservoirs and emit pollutants sufficiently consistent to supply CO_2 operations. A combination of a carbon tax and sustained high oil prices incentivizes cooperation between oil companies and local power plants. Canada's geography and location of reservoirs versus population centers renders economical agreements problematic.

In the U.S., 1 trillion cubic feet (Tcf) of CO_2 is used for EOR annually with 75% going into the Permian Basin. A 2005 study by the Department of Energy estimated the potential long term market of CO_2 for these purposes at 380 Tcf (Reserves, 2007). Successful cooperation among sectors existed; a Wyoming gas processing plant owned by Exxon Mobil directs over 4 million metric tons of CO_2 annually to EOR operations. EnCana, a Canadian oil company involved in several large Canadian oil sands plays, purchases CO_2 from a lignite-fired coal gasification plant in North Dakota. Injecting 5,000 metric tons of CO_2 daily in conventional reservoirs, EnCana predicts total sequestered CO_2 to exceed 30 million tons. The productive lifespan of the oil field is estimated to grow by 25 years with IOR of 130 million barrels. It's worth noting the agreement results in $30 million in additional revenue for the gasification plant and a 330 kilometer (km), $100 million pipeline was built solely for this agreement (Melzer, 2002). While the development of this market is ongoing, it may be significant as the value of gas and steam co-injection becomes better understood.

Second only to miscibility, the size of the gas injection measured as a percentage of reservoir pore volume (HCPV) is of utmost importance operationally. Ranging from 30-80% HCPV, significant uncertainty surrounds optimum injection volume. Firms determine the ideal injection design through lab experiments, trial and error, and pilot projects within the formation. The primary contributor to the upper limit is inexperience beyond the 80-100% HCPV threshold. Cost and solvent supply are factors but are offset if higher injection quantities continue to increase sweep efficiency and ultimately recovery. A 2010 study by the Society of Petroleum Engineers focusing on the effectiveness of larger HCPV injections found recovery can be improved economically to levels as high as 190% HCPV. The study demonstrated levels up to 26% of OOIP IOR using larger volumes of gas compared to standard results of 10-15% OOIP (Merchant, 2010). If the metrics of this study apply on a broad scale, the value and productive capacity of fields where CO_2 injection works increase dramatically. Gas injection's potential as steam co-injection is promising based on lab experiments and actual field data from Cenovus's mature SAGD projects (Cenovus Energy, 2013).

In order to maximize recovery and profitability, water and CO_2 are carefully cycled through the reservoir in specific slug sizes and intervals. Solvent injection alone often coincides with viscous fingering, or the channeling of gas through the oil without adequate sweep efficiency. Adjusting the volume and pressure of water is a proven and economic mechanism to improve conformance control and maximize the mobilization of oil. Current reservoir modeling technology allows optimization of HCPV and WAG intervals with modest reliability. While modeling has produced results consistent with actual production figures, it relies upon thoughtful input of very accurate reservoir characteristics and a thorough understanding of the inherent limitations of any modeling software.

One advantage of CO_2 EOR is a declining need for fresh CO_2 as the project matures. The largest CO_2 slug is usually performed at the start of the project with additional slugs continuously tapered down. This combined with the fact much of the CO_2 is recycled from produced oil causes overall CO_2 costs to decay to a smaller fraction of operating costs over time (Merchant, 2010).

3.1.5 Gas Injection in High Viscosity Oil

Gas injection is used in many conventional crude reservoirs but implemented sparingly in Canadian heavy oil projects to date. The ability to leverage gas injection on even a small fraction of heavy oil deposits could have a material economic impact. VAPEX is a solvent process designed specifically for heavier oils. With a pair of horizontal wells giving it similar structure to SAGD, the top well injects vaporized hydrocarbon solvent to reduce bitumen viscosity. Through gravity drainage, the effected bitumen eventually drains to the producer well. While some Canadian oil deposits are within the viscosity range VAPEX is at least minimally effective, most are too viscous for its use independent of thermal methods. Natural gas is already transported across Canada and supplies the majority of energy used to generate steam for the 100+ active thermal projects. This provides a unique opportunity to quickly integrate natural gas injection into steam projects if engineers determine it optimal. While not all gas injection industry knowledge transfers to oil sands projects, it does provide an idea of how its unique recovery mechanisms might assist thermal applications. Importantly, many reservoir simulators, such as CMG Stars, already have gas injection capability giving a foundation to combine it with thermal processes for initial analyses.

3.2 Chemical Applications

Chemical EOR's attributes and limitations are considerably different than gas and thermal. While historically applied only to medium and high API crudes, the breadth and essentially unlimited customization of chemical applications bodes well with future integration with mainstream approaches to heavy oil recovery. Steam foam, for instance, is generated when certain surfactants are vaporized into the injected steam and substantially improves the steam's mobility ratio and thermal efficiency. This is demonstrated through field results and reservoir simulations performed through CMG-Stars.

Chemical EOR has a mature technical history surpassing forty years with common incremental recovery rates of 5-15% in conventional reservoirs. Though chemical EOR reached its production peak in the 1980's, it is still heavily utilized and researched. The DOE estimates less than 5% of U.S. EOR production is due to chemical floods (Department of Energy, 2013). China has the largest polymer flooding project with 220,000 bbls per day production with a cost of only $1-2 in chemicals per barrel of oil (Wang, Dong, Fu, & Jun, 2009). Surfactant, polymer, gel, and alkaline are the most common chemical agents. The influence chemical injections can have on the crude oil-brine-rock system is extremely broad and subsequently carries many possibilities while necessitating careful design.

3.2.1 Surfactants

Medium to low chain molecules, surfactants modify the wettability of reservoir rock, effectively lower the interfacial tension between oil and water, and positively impact capillary forces to make oil more mobile. Surfactants can also be used to generate foams or emulsions to highly specific requirements to improve recovery on a reservoir by reservoir basis. These molecules have both a hydrophilic and hydrophobic section and thus accumulate at the interface. Synthetic surfactants are hydrophilic and injected as slugs while naturally produced versions, consisting of naphthenic acid and alkali, are hydrophobic and generated in-situ. Both types reduce interfacial tension between water and oil and subsequently decrease capillary forces preventing oil from moving through water-wet restrictions. The objective is to obtain a high capillary number, the ratio between viscous and capillary forces, resulting in viscous forces governing system dynamics and allowing residual oil to mobilize. Similarly, raising the bond number, the ratio of gravity to capillary forces, assists in gravity-dominated displacement and can be accomplished through surfactant injection. At a cost of $10-20 per barrel, industry is constantly improving surfactant composition and lowering the amount expended. Long – chain polymers increase water viscosity to improve water flood sweep efficiency and well conformance control (Wang, Dong, Fu, & Jun, 2009). In this context, sweep efficiency is defined as the percentage of oil contacted by the injected phase.

3.1.2 Polymers

Polymers are chemicals used to increase the viscosity of a water flood. The improvement in mobility ratio of the injected fluids is the most important recovery mechanism. Polymers benefit from relative simplicity and lower cost versus surfactants while still customizable. Higher viscosity polymer gels are even more effective in increasing water viscosity and can be strategically routed to block unfavorable flow. Canadian Natural Resources has had significant success in their Pelican Lake operations by using polymer enhanced water flooding at $3-$4/bbl additional operating costs and $10-$13 barrel in total capital costs. Ultimate recovery is expected to rise from 10-12% to 17% OOIP. Full response at Pelican Lake occurs within 9-24 months from initial injection and the firm is experimenting with floods in areas with low crude quality (Canadian Natural Resources, 2013).

3.1.3 Alkaline

Alkaline chemicals such as sodium carbonate, hydroxide, orthosilicate, and metaborate raise pH and correctly designed cause crude oil to generate its own natural surfactant. When successful, this technique is less expensive than using surfactant itself at about $5-10 per incremental barrel. Not all crudes are suitable for this treatment and only those with sufficient acid content generate material amounts of soap in-situ when contacted by alkalines. The acid number is defined as the amount of potassium hydroxide (KOH) per gram of crude sample; an acid number of .5 mg KOH per gram of oil or greater is an ideal candidate while figures as low as .2 mg KOH per gram of oil could be suitable. Crude below 20° API and sandstone reservoirs below 200° F show the best field results. Problems associated with alkaline flooding are cation exchange, reaction with solids, precipitation of hydroxides, and the necessity of an acidic crude (Wang, Dong, Fu, & Jun, 2009).

3.1.4 Alkaline-Surfactant-Polymer (ASP)

The choice of chemical application is further complicated by the fact in-situ generated surfactants may not be as effective as those tailored to the project in a laboratory or based off field trials. The most promising chemical flood, both in terms of laboratory results and in the field, is a combination of the above processes called Alkaline-Surfactant-Polymer (ASP). As an example why this process often achieves superior results, surfactant may be injected to mobilize the oil to a particular degree then a polymer drive, customized to form an ideal mobility ratio versus the newly mobilized oil, pushes the oil toward the producer and minimizes viscous fingering and other causes of poor sweep efficiency. The costs and layers of complexity involved in an ASP process can be prohibitive, especially for firms without past chemical injection experience. The amount of chemicals required varies widely depending on the injection design and reservoir characteristics; a conservative estimate is 25-35$ per barrel in chemical costs for a thorough ASP process.

3.1.5 Reservoir and Oil Suitability

While chemical applications are generally insensitive to depth and pressure, fluctuations in reservoir temperature and microbial activity can render a complex, capital intensive chemical flood useless. Though surmountable, the temperature limitation is a significant challenge when chemical applications must withstand steam injection's 250 °C or greater in-situ environment. In addition, the range of oil API favorable to chemical processes alone is narrow and not far from those producible without EOR. As research and projects in the field refine chemical EOR, economic recovery increases of 15% OOIP may be common in many reservoirs. Unlike many thermal applications, most chemical processes seek to increase recovery in reservoirs where primary and secondary processes are at least mildly effective. An interesting development in polymer engineering is designer chemicals that do not increase water viscosity until certain parameters are met. For instance, injectivity can be that of water until once the solution reaches reservoir temperature. At that point, the chemicals' structure changes and increases viscosity at a predetermined rate optimized for the project. This alleviates injectivity issues with high viscosity polymer applications and allows engineers to block high permeability zones deeper in the reservoir than they could otherwise. While polymers eventually degrade within the reservoir, careful temperature logging is required to ensure blockages do not form in inopportune areas. Mastering the molecular structure and implementation of designer chemicals could benefit fractured and other types of reservoirs with poor sweep efficiencies for water floods; especially those with decent mobility ratios. The designer element and associated temperature "trigger" bode well for hybrid thermal operations.

3.1.5 ASP Flood Illustration

To illustrate the components involved, a real world ASP slug used in Berea Sandstone consisted of .1 weight percentage (wt%) C_{16-18} ABS, .01 wt% c_{20-24} IOS, 1 wt% DGBE cosolvent, 3000 parts per million (ppm) Flopaam^{TM} 3630S, and 2.75 wt% Na_2CO_3 in .6 wt% NaCl injected at 1.3 ft/day. The polymer drive used after the initial ASP slug consisted of 2000 ppm Flopaam^{TM} 3630S and .6 wt% TDS also at a velocity of 1.3 ft/day. The ASP slug used a higher concentration of Flopaam^{TM} polymer of 3000 ppm versus the polymer drive's 2000 ppm. The injection size is also of careful consideration; the more expensive per unit volume ASP slug was .3 PV while the polymer drive was 1.7 PV. Both drives had viscosities of 29 cP compared to the oil bank of 20 cP resulting in a favorable mobility ratio (Pope, 2007).

Other parameters in the field, such as surfactant retention rate, influence project economics and subsequent flood design. The following examples illustrate the significance of mobility control. In the first core flood of the above design, polymer viscosity was 48 cP, surfactant retention was .11 mg of surfactant per gram of oil, and cumulative oil recovered was 70% OOIP. Increasing polymer viscosity to 90 cP resulted in surfactant retention of only .02 mg/g and cumulative oil production above 90%. The cost differential of polymer versus surfactant, much less the associated improved oil production, is reason enough to strongly consider higher polymer viscosities despite the increased initial capital expenditures. Interactions between the chemicals, reservoir rock, and oil seem to benefit ASP. For instance, alkali NA_2CO_3 appears to reduce adsorption of surfactant on some reservoir rock. Per experiments completed by Hirasaki and Miller in 2007, adsorption of surfactant at 5% NaCl on calcite was 3.5 mmol/m^2 but decreased to 1 mmol/m with 1% Na_2CO_3 added to the solution. (Hirasaki and Miller, 2007).

The Daqing oil field in China is the largest chemical flood case study. Their chemical applications consistently reduced water cut while increasing oil production for incremental oil recovery of 20% OOIP through ASP. Maintaining optimum ASP flood design has proved challenging and project economics are still unfavorable compared to simple polymer floods although total recovery is superior (Wang, Dong, Fu, & Jun, 2009). Much of the field data is from the late 2000's when the oil was 40-70% of today's $100-110 Brent crude prices. It is possible, if not probable, ASP processes previously near the economic limit at are now profitable. Cenovus is optimistic about the SAP pilot test in Christina Lake, for example.

Pelican Lake, a large ongoing project in Alberta managed by Canadian Natural Resources (NYSE:CNQ), uses polymer flood operations to stimulate production. Spending over $530 million on operations since 2011, the firm's long term plan is to use polymer on up to 88% of its Pelican Lake wells. Cenovus Energy (NYSE:CVE) is also using EOR to produce more than 20,000 bbls/d from Pelican Lake.

In the context of heavy oil applications, chemical floods alone cannot produce significant volumes of hydrocarbons. Used in conjunction with thermal, however, chemical processes can play a meaningful role toward maximizing production rates and ultimate recovery, enhancing project economics, and reducing per barrel emissions. Further development of cheap designer chemicals with increased resilience to high temperatures is likely a first step for steam injection and chemical applications to coexist commercially on a broader scale.

Chapter 4

Thermal Applications

Thermal methods, most commonly steam injection, are what firms in Canada use to produce the vast amount of bitumen excluding surface extraction. Thermal EOR is extremely effective at recovering high viscosity, less than 15° API oil. Recovery rates vary between 20-65% OOIP, though instances exceeding 85% have occurred. Thermal is often the only known technique to recover meaningful amounts of below 15° API oil outside of costly and potentially environmentally contentious mining. Many reservoir properties limiting the effectiveness of chemical and solvent methods, such as salinity, pressure, and microbial activity, do not affect thermal EOR. Depths beyond 1500 m, however, strain project economics due to heat loss; strategies to substantially reduce this exist such as heavily insulated wells and surface lines. In-situ combustion, a system creating heat within the well instead of transmitting it from the surface, is an alternative to pumping steam to great depths and has been successful. It is, however, particularly complex and requires detailed reservoir analysis and project planning. The exact physics and interface interactions involved at some stages of the process are also unclear hindering accurate simulations and project repeatability.

Most thermal processes involve intricate, multiple well structures pumping steam into the reservoir to lower the oil's viscosity from above 10,000 cP to approximately 100 cP, or the equivalent of transforming a substance thicker than peanut butter into one less viscous than olive oil. The swept zone is often controllable and predictable with recovery typically beginning within days of initial treatment. Fractures, high permeability zones, and reservoir heterogeneity in general still mitigate recoveries and create challenges in thermal projects. Steam Assisted Gravity Drain (SAGD), Steam Drive, and Cyclic Steam Stimulation (CSS) are the most common methods. While the swept zone and increase in recovery rates are excellent, thermal EOR is energy and capital intensive and requires greater than historically average oil prices to be economical. In remote areas, recovered crude oil instead of cleaner burning and cheaper natural gas may have to be used to generate steam to then be pumped down the wellbore.

There are several immediate drawbacks to using produced oil. First, the crude consumed by on site boilers is of high economic value and under almost any other circumstances would not be used to generate electricity. Secondly, environmental concerns are numerous. Consuming natural gas instead of oil to power boilers, whether from an external source or the reservoir itself, reduces costs and pollution by 50% or greater. The vast majority of current thermal projects rely on natural gas for these reasons. Engineers and project managers hesitate to rely on sources other than the produced oil, however, when gas co-production is minimal and no pipeline network exists nearby since crude is the only fuel with guaranteed availability during the reservoir's lifespan. Heavy oil and bitumen formations do not have the equivalent gas co-production common to conventional and shale oil. Unlike chemical and solvent based EOR, thermal techniques rely on the EOR's mechanisms for most if not all of the reservoir's output. The inability to generate steam halts the operation.

Thermal is consistently the most expensive EOR technique; several large scale projects in Canada necessitate $70 bbl oil for acceptable profitability although costs are continuously decreasing and are expected to decline further (Department of Energy, 2013). Cenovus Energy, a firm with one of the best steam to oil ratios in SAGD applications, uses only approximately 2.1 barrels of steam per produced barrel of oil in both its Foster Creek and Christina Lake projects through 2012. This level of efficiency is highly correlated with strong profitability (Cenovus Energy, 2013) All steam injections need a water source, steam generators, the ability to produce approximately 80% quality steam, some degree of pipe and injection line insulation, and downhole equipment capable of withstanding high temperatures and cycles of water and produced fluids. Brackish or high salinity water can be used in substitution of fresh water but puts additional stress on operational equipment.

4.1 Cyclic Steam Stimulation (CSS)

Cyclic Steam Stimulation has been used successfully by Imperial Oil at Cold Lake since 1985. It's currently implemented by Canadian National Resources at Primrose and Wolf Lake and by Shell Canada at Peace River. CSS originated in the 1950's in the heavy oil fields of California (Butler, 1991). The heat carried by steam reduces oil viscosity; this decrease is the main recovery mechanism as is the case for thermal recovery overall. The process, along with most types of steam injection, also provides pressure maintenance. CSS takes place in cycles with carefully designed injection, soak times, and production periods all from a single well. Recoveries are on the lower end of thermal methods ranging from 15-35% OOIP with steam to oil ratios of approximately 2-3.5 barrels of steam per incremental barrel of oil produced. Using a long horizontal well in the ideal reservoir could result in recovery closer to 50% though it is not presently common (Canadian Natural Resources, 2013).

4.1.1 Well Configuration and Injection Cycle

Several strategies exist but all use one well per application. Originally, a single vertical was used though firms are now using a single lateral well since the additional capital costs are potentially minimal compared to the significantly enhanced oil recovery (Canadian Natural Resources, 2013). Initial soak injections are the largest and reach fifteen thousand barrels of steam. Some firms, such as Shell, produce the heated oil immediately while others allow the steam to soak for several days or weeks. Depending on reservoir response and economics, this cycle may occur as many as twenty times. Specifically, the first stage of steam injection may last two to thirty days. In the second phase the well is shut in over similar time frames as the steam condenses to hot water. Through convection, heat expands into the reservoir lowering the oil's viscosity in preparation for the final stage of production which occurs over one to six months. Uncertainty surrounds the optimization of this timeline. While the final phase is often dictated by well performance and the production decline rate, the first two stages may require careful analysis through trial and error. A shut in time of two days versus thirty over twenty cycles adds a year and a half to the project's completion time. Part of the first phase is limited by steam injectivity but determining the optimum volume is difficult. Achieving the ideal injection rate may require fracturing the reservoir horizontally through the pay zone (Fair, Trudell, Boone, Scott, & Speirs, 2008).

4.1.2 Ideal Reservoir Characteristics and Recovery Mechanisms

CSS's formation requirements are similar to other applications with preferred depths less than 5,000 feet (ft), high oil saturations, thickness greater than 20 ft, and permeability greater than 500 milidarcies (md). In general, one barrel of produced oil for three to four barrels of injected steam correlates with an economic project. Although not as complex as most other thermal processes, Cold Lake's CSS is the largest current thermal recovery project in Canada as well as North America. Steam is injected on average at 300° C and 1500 psi with a resulting production of 140,000 bbls per day from 3,800 active wells (Canadian Natural Resources, 2013). The production of "foamy oil," an emulsion of approximately fifty percent water in bitumen, is an important recovery mechanism. In the later stages of CSS, gravity drainage along the walls of the produced zone become increasingly important. This mechanism develops as the steam chamber and thus impacted surface area increases. Due to the significant local expansion of the formation, well stability and understanding local geomechanics are critical for long term project success. CSS represents 25-35% of current thermal activity in the oil sands but its expected growth rates are not as high as other thermal processes with higher recovery rates, notably SAGD (Canadian Natural Resources, 2013).

4.2 Steam Drive

Steam drives, also known as steam floods, are a dynamic process using many of the same principles as CSS but with at least two vertical wells; various combinations and patterns of producers and injectors have been successful. An example is a 5-spot pattern with one central injector and four producers. The injected steam forms a front of hot water and steam that then creates an adjacent mobile oil front that is pushed toward the producer(s) (Deo, Forster, & Schamel, 1999).

Steam is injected at approximately 300 °C and 1,500 psi. In reservoirs with unfavorable initial injectivity, CSS may be utilized for one or more cycles to allow sufficient steam volumes to support a steam flood. The angle and velocity of the steam and oil contact zone are important considerations and can be manipulated, often accurately, through well placement, perforation design on the injector, as well as optimizing steam quality and injection rate. Steam floods are best suited for heavy, viscous oils in formations with high oil saturations, at least 20 ft of pay zone, and greater than 500 md permeability. It is among the most practical and flexible of thermal methods; other applications often convert to steam floods once their efficiency degrades beyond the economic limit. Recovery of OOIP is 50-65% on average with favorable steam to oil ratios of 3-5 barrels of steam per incremental barrel of oil (Deo, Forster, & Schamel, 1999).

4.3 Steam Assisted Gravity Drainage (SAGD)

SAGD is a more complex method suitable for reservoirs requiring more precise applications and or greater depths than CSS or standard steam floods. This method has the highest current and expected growth rates in the field of heavy oil and bitumen recovery in Canada. The process was invented in the 1970s by Dr. Roger Butler while an engineer at Imperial Oil. Dr. Butler later become director of technical programs at the Alberta Oil Sands Technology and Research Authority, now known as the Alberta Energy Research Institute; an organization that invested in and supported SAGD as an important innovation in heavy oil recovery (Canadian Petroleum Hall of Fame, 2010). SAGD is credited as a major driver of Canada joining the ranks of Venezuela and the other oil super powers.

4.3.1 Recovery Processes and Efficiencies

Heat conduction is the primary driver with convection an important process on the steam chamber boundary. Production is dominated by gravity drainage as oil flows from the steam chamber edge down toward the producer. Assuming sufficient steam injectivity and generation, production rates increase with the volume of the steam chamber as more of the reservoir's surface area is affected. Oil viscosity is reduced by the steam until it becomes mobile and flows to the producer along with condensed water. Depending on reservoir structure, the steam chamber may eventually reach the overburden and decline rapidly in thermal efficiency. The horizontal unswept zones decrease over time with overall recovery factor surpassing 50% on average and as high as 90%. Canadian Natural Resources consistently achieves 50-70% recovery (Canadian Natural Resources, 2013). Steam to oil ratios average three barrels of steam per incremental barrel of oil. Due to its flexibility and extremely high recovery efficiency, SAGD is recognized for developing a new phase of thermal projects and activity in heavy oil rich regions such as Canada.

4.3.2 Design Parameters

SAGD design varies but customarily consists of two carefully placed lateral wells. The producer is normally four to seven meters below the injector. Horizontal well angles, perforation location and frequency, well placement, and steam injection rates are critical to optimizing steam conformance. Important parameters outside of the control of engineers and common to other thermal methods are net pay thickness, oil saturation, porosity, vertical permeability, shale layers, and overburden characteristics. Shale layers are a unique challenge as they can influence steam chamber expansion and isolate portions of the reservoir from heat transfer. Drilling the production well first and as close to the bottom of the reservoir as possible provides maximum production potential. An additional challenge is achieving initial communication between the wells (Munoz, 2013).

4.3.3 Establishing Well Communication

Using electric heaters to establish more rapid communication in heavy oil reservoirs is a still somewhat immature methodology. Systems benefits include precision applications, minimal energy losses, temperature control, and flexibility in power generation. Drawbacks are limited field experience, less efficiency on a BTU basis than natural gas, capacity restrictions, and general inexperience with electrical heating systems by petroleum engineers (Sandberg, Hale, & Kovscek, 2013).

In 2006, electric heating began commercially on twelve wells in the Bakersfield area of California; the site of one of oldest ongoing thermal projects. As an example, one application involved 14.3° API crude and a virgin reservoir temperature of 120 °F. Using a 536 ft heated cable with total power output of 25.7 kW, production mirrored that of prior CSS applications on the same well but with the benefit of no water cut. Across the twelve wells there was an average 400% increase in production using electrical heating. There is a weak but positive correlation between lower API crudes and a greater increase in production from electric heating. Well number 9, for instance, has 8.5 API crude and achieved a 1400% increase. Results vary across oil, reservoir, and heating system properties but sufficient pilot testing has occurred to demonstrate the recovery mechanisms of electric heating, ranging from simple viscosity reduction to complex thermal cracking and hydrogenation, work well in heavier oils provided electricity demands are met. This limitation is not a significant factor to achieve improved communication between SAGD wells or other thermal projects where initial viscosity reduction can be troublesome and or time consuming (Sandberg, Hale, & Kovscek, 2013).

Be it SAGD or other thermal processes, injected steam must fill volumes produced oil previously occupied. An exception to this is the rare phenomenon when steam volumes surpass produced oil volumes and the earth's surface rises slightly to make up the difference. Poor initial production rate and uneven steam chamber development, be it from unidentified shale layers or quicker than expected contact with the cap rock, are two common causes for well underperformance. Once communication is observed, steam is often circulated continuously for up to ninety days. A range of 400 to 1000 barrels per day per well pair is normal once communication is established and the steam chamber forms properly. Alberta's SAGD production currently exceeds 500,000 bbls per day and is the leading thermal process (Jonasson & Kerr, 2013).

Subcool control, or steam-trap control, is vital to a productive and long lasting SAGD operation. While a broad topic in of itself, subcool control is effectively maintaining the proper liquid level at the producer. Operators must determine the ideal subcool target temperature difference; usually in the range of 10° to 30° C. The parameters dictating the fluid level above the producer are the pressure difference between the two wells, the subcool, and the production rate. Inadequate steam-trap control may result in steam breakthrough from the injector directly to the producer (Yuan & Nugent, 2013).

Reservoir pressure maintenance is also imperative to a favorable steam oil ratio as "SAGD productivity is proportional to the square root of the inverse of viscosity" (Jonasson & Kerr, 2013). While operators generally maintain pressures above the reservoir's natural state, the latent heat content of the steam degrades as temperature and pressure rises resulting in increased losses to the overburden and rock matrix in general (Jonasson & Kerr, 2013).

Based on various expert opinions as well as an analysis of current and planned commercial projects, the general consensus is SAGD is the preferred method for highly viscous bitumen with viscosities exceeding 1,000,000 cP in Athabasca where surface extraction is not feasible (MEG Energy, 2013). Combining SAGD with solvent injection or Vaporized Extraction (VAPEX) provides further opportunities to improve oil recovery or maintain it with greater thermal and therefore cost efficiency. The hybrid thermal section later the in document expands on this topic. Projects are shut down when the size or efficiency of the steam chamber can no longer transfer enough heat to satisfy viscosity reduction needs. This can be due to heat losses to reservoir rock, injectivity issues, or limitations based on well placement. The steam oil ratio ultimately degrades until the economic limit is reached. These circumstances reinforce the criticality of well placement and spacing. It is also possible to decrease steam injection rates significantly, even totally, toward the end of a properly executed steam process and still sustain economic levels of production. As of Q1 2013, Cenovus converted its first set of SAGD wells in Foster Creek to what it calls blow down. Steam injection is decreased and coupled with less expensive methane co-injection. The firm noted lower operating costs and the ability to direct steam to new projects where it is more valuable (Cenovus Energy, 2013).

4.3.4 Operating Costs and Controls

While operating expenses vary across firms and project scale, Cenovus is transparent on costs, operates many of the largest thermal projects, and claims an industry best steam to oil ratio; the key metric of steam efficiency. These properties make its results a reasonable starting point for ascertaining a well-run SAGD project's costs. As of Q1 2013, Foster Creek's heavy oil SAGD project averaged $14.03/bbl in operating costs with fuel's portion, in this case 100% natural gas, only $2.91/bbl. Given gas costs at the time, this is approximately 1 MMcf/bbl (Cenovus Energy, 2013).

Q2 results had Foster Creek operating costs of $16.19/bbl with fuel costs analogous to Q1 at $2.39/bbl; Christina Lake, the company's other major SAGD project, had similar figures (Cenovus Energy, 2013). Recently published Q3 2013 results were $17.12/bbl for Foster Creek and $11.46/bbl for Christina Lake. The difference to previous quarters was primarily due to changes in production volumes; a planned rise for Christina Lake increased efficiencies across the board while a decrease occurred in Foster Creek for maintenance and a planned operational turnaround in September (Cenovus Energy, 2013).

While oil produced with these operational figures is priced competitively, even discounting for heavy oil's lower value but greater refining and transportation costs, it is difficult to quantify the impact of initial project expenses, potential operational symmetries unique to Cenovus, and other factors not readily apparent in quarterly reports using Generally Accepted Accounting Principles (GAAP) accounting. Cenovus and firms like it are able to leverage the derivatives market for additional price protection and reliability. Cenovus's management allows the hedging of 75% of current year production, 50% for the following year, and 25% for two years out (Cenovus Energy, 2013). Given the illiquidity of the crude futures market more than a few years out on the curve, their hedging operations could be judged as reaping the majority of commodity price security offered by the financial markets. The ability to at least lock-in prices for the next few years eases the short term risks of capital intensive thermal projects and offsets the shock of sudden drops in crude prices (Cenovus Energy, 2013).

4.4 In-situ Combustion

Despite being responsible historically for only 1-10% of thermal EOR production, generating steam downhole through in-situ combustion, instead of at the surface, carries many benefits.

4.4.1 Advantages and Disadvantages

First, the 10-25% of total heat losses from surface infrastructure and the well itself are avoided by using in-situ combustion. Secondly, reservoirs at depths beyond what other thermal processes can handle may be economically extracted using this method. Sandia National Laboratories determined 3,000 ft as the average depth for heavy oil reservoirs at which in-situ combustion surpasses surface generation of steam in cost efficiency (Castrogiovanni & Ware, 2011). This method causes minimal disturbances to the surface environment; often critical in areas such as Alaska or Siberia where maintaining the integrity of permafrost is important. A 2007 USGS study of heavy oil and bitumen determined over 96% of these resources were at depths beyond 2,500 ft.

While the thermal efficiency of the other processes continue to increase incrementally, the significance of economical in-situ combustion processes going forward is considerable (Meyer, Attanasi, & Freeman, 2007). Standard in-situ combustion works by compressed air sent through the injector toward the bottomhole heater. Upon ignition, a flame front is generated and then manipulated through air injection rates. The physics occurring throughout the reservoir are complex and not entirely understood, but the flame front, vaporized oil and water, condensed hot water, combustion gases, and low viscosity oil bank move toward the producer. A series of processes take place between the flame front and the production well. Moving from the burned zone toward the producer, these zones are categorized as the vaporizing, condensing, oil bank, and combustion gas zones. Downhole steam generators can also function off natural gas as a fuel source. Technical and economic studies demonstrate economic viability for in-situ combustion, even at great depths, at $75/bbl (Castrogiovanni & Ware, 2011).

4.4.2 Fuel Source and Recovery Rates

In-situ combustion can use the formation's crude as its fuel source; determining exact figures on oil consumption on a volumetric or percentage of output basis is difficult. In addition to the forward combustion model described above, other techniques integrate water flooding and what is called reverse combustion. The latter technique turns the injector well into a producer similar to CSS. Other injection wells within the same reservoir can assist the process since air cannot be injected to sustain combustion once the well is converted to a production well. This process has not been successful in field trials made public as of late 2013 (Gunn & Krantz, 1980).

Recovery mechanisms are similar to other thermal processes but with the addition of steam distillation and thermal cracking. Another benefit is a portion of the oil's coke, a component of heavy oils that is costly to refine, is consumed. Coke deposition throughout the process must be balanced so sufficient is produced to maintain the combustion process but not so much that the flame front stagnates. High coke deposits require proportionately more air injection to preserve combustion. Pressure maintenance is also assisted by the continuous air injection. An already difficult process to control, horizontal sweep efficiency is often poor in thick formations as the flame front tends to rise toward the upper portions of the reservoir. Produced flue gases present environmental concerns and severe corrosion can occur due to low pH hot water flow (Castrogiovanni & Ware, 2011). Production from in-situ projects have higher sand cuts, oil-water emulsion issues, and increased operational complexity due to extremely high temperatures and deposition of combustion outputs such as waxes and carbon. Recovery of OOIP range from 10-50% with 10 MCF of air injected per incremental barrel of oil produced. Although an involved process with some interactions still poorly understood, in-situ projects have a commercial history going back to the 1970's (Castrogiovanni & Ware, 2011). The oldest active in-situ project in the U.S. began in 1978 in Buffalo field, South Dakota, and an IOR of 18.1 million bbls in 2009 (Kumar & Gutierrez, 2010).

4.4.3 Toe to Heal Air Injection (THAI)

THAI is a relatively new method developed and patented by Petrobank Energy and Resources Ltd. It involves a vertical air injection well paired with a horizontal production well. The combustion front, supplied with air from the injection well, lowers oil viscosity and through gravity drainage produces from the lower horizontal well. Given suitable reservoir characteristics and proper well placement, production of 80% of OOIP is the target with 50-60% average. Petrobank is developing another process termed Controlled Atmospheric Pressure Resin Infusion (CAPRI) which pulls oil through a catalyst lining the lower pipe. It's expected to increase API by another 7° versus THAI ((Xia & Greaves, 2001).

Operationally, THAI is initiated with an average of three months standard steam injection from the vertical well. Air injection then begins and combustion is initiated raising reservoir temperatures to 400 to 600 °C. Thermal cracking and coking occurs as approximately 10% of the oil is consumed and the remaining oil upgraded. Field tests demonstrate an increase in API gravity of up to 16° and a reduction of viscosity to less than 100 cP. A major benefit of this process is after the three month steam injection, no additional water or fuel input is necessary. According to Petrobank, the process can still yield 70-80% of OOIP even in thinner reservoirs and those with intermittent shale layers, both of which are problematic for standard steam processes (Xia & Greaves, 2001).

4.4.4 Combustion Overhead Gravity Drainage (COGD)

COGD employs a number of vertical air injection wells with a horizontal production well. The gravity drainage recovery mechanism is similar to that of SAGD. Once the bitumen is prepped for ignition, usually through 1-3 cycles of CSS, the combustion first occurs at the upper portions of the bitumen. The viscosity reduction eventually mobilizes oil along the production well. The relevance of COGD is it maintains production levels of SAGD but with water savings as high as 80% due to the absence of continuous steam injection. There are limitations and concerns with each in-situ combustion process. THAI, for example, suffers from poor lateral sweep efficiency and the tendency for the injected solvent to immediately reach the producing well. When undesirable connectivity between the injected air and producer well is avoided, high viscosity oils >100,000 cP often cause injectivity problems as the cold oil will not flow. Steam Assisted Gravity Drainage with the Addition of Oxygen Injection is a similar method currently under development for heavier oils but with no field trials. It uses pure oxygen, focuses on segregating the solvent from the steam, places vent gas wells far from the site of oxygen injection, and minimizing steam usage (Jonasson & Kerr, 2013).

Due to the externalities associated with thermal cracking and using oil for fuel, 10-27° API crude with viscosity less than 500 cP and sufficient asphaltic components to aid coke deposition is ideal. Reservoirs should be greater than 40 °C, average permeability greater than 50 mD, high porosity, and oil saturation greater than 50% pore volume (Kovscek, Castanier, & Gerritsen, 2013).

Chapter 5

Advanced and Hybrid Techniques

Several thermal technologies are under development but many are without sufficient field history to reliably determine their commercial success rate or recovery potential. Among these are thermal conduction, various applications involving electric heating, and hybrid technologies. Combining steam injection with chemical and or solvent applications has garnered significant research and literary attention.

5.1 Steam and Chemicals

Combining steam with the chemical applications outlined previously yields interesting and often promising results both from a physics and reservoir simulation perspective. Each of these methodologies and their recovery mechanisms are outlined.

5.1.1 Surfactant and Steam

Steam foam, for instance, is a hybrid steam and chemical flood. The foam is generated through a tailored surfactant and steam combination. While steam's heat transfer remains the primary driver of viscosity reduction and subsequent oil recovery, the steam foam component improves several parameters. This hybrid technique results in enhanced sweep efficiency and alleviates gravity override in high permeability layers. The additional mobility control also improves areal sweep efficiency through reduced channeling compared to steam alone. Like polymer's benefit to a water flood, the thicker steam foam naturally tends to plug high permeability zones and divert steam flow toward unswept portions of the reservoir while increasing the pressure gradient; leading toward the displacement of greater volumes of oil. Surfactant reduces interfacial tension while mobilizing oil through emulsification. The multiple recovery mechanisms are particularly challenging to fully integrate into numerical reservoir simulation software

(Lau, 2012). Per the included dat. file, several reservoir simulations were performed to estimate steam foam's recovery enhancement as well as verify the physics involved.

Due to a limited number of well documented field projects, uncertainty remains concerning optimum injection cycles, the ideal amount of chemicals, and incremental improvement in heat transfer through increased steam efficiency. Given the high cost of thermal projects, even against most high concentration surfactant floods, it is reasonable to assume a measureable increase in steam efficiency through steam foam could offset the cost of the chemicals without taking into consideration the added benefit of improved recovery.

Lab experiments and simulations suggest the surfactant-steam process (SSP) accelerates oil production, improves SOR, and increases ultimate recovery marginally. Tests on Canadian oil sands used a broad range of surfactants with corresponding IOR of 6-16% depending on the surfactant used against the standard SAGD process. Increases in ultimate recovery and reductions in the cumulative steam-to-oil ratio (CSOR) are both average approximately 10% (Zeidani & Gupta, 2013).

SSP achieves optimum results using a surfactant that withstands and functions at temperatures exceeding 320° Celsius for extended periods of time, substantially reduces IFT, vaporizes down hole under the conditions of a steam injection, is compatible with reservoir water, alters wettability to water, and forms an oil-in-water emulsion (Zeidani & Gupta, 2013). Few surfactants have these characteristics with downhole vaporization and resilience under high temperatures the most difficult to attain. Non-ionic surfactants meet these requirements best due to their tendency to interact with interfacial regions and ability to change the properties of mixtures in the areas of phase equilibrium, solubility, and miscibility, among others. Representing an empirical expression for a surfactant's hydrophilic and hydrophobic tendencies, the Hydrophile-Lipophile Balance (HLB) is on a 1 to 20 scale. Higher numbers coincide with the oil-in-water emulsions desired in SSP. While conclusive field data is difficult to find, lab tests have shown if a surfactant is an emulsifier, an HLB below 10 generally harms recovery performance (Zeidani & Gupta, 2013). The critical micelle concentration (CMC), defined as the surfactant concentration above which micelles form and additional surfactants do not meaningfully alter surface tension. Understanding the impact of pressure and temperature on CMC ensures the surfactants perform properly and the lowest effective dosage is used to minimize costs. Determining the proper surfactant concentration over the project's lifespan, usually in the range of 500-2000 ppm, also has a material impact on project economics and recovery rates (Zeidani & Gupta, 2013).

An additional consideration discovered in testing is surfactants react differently in-situ depending on the characteristics of the hydrocarbon source. Even among the relatively narrow range of surfactants both resistant to thermal degradation and demonstrating extensive IFT reduction with bitumen, the creation of addition in-situ surfactants from reactions with the bitumen's acids, asphaltene particles, and resins, varied (Zeidani & Gupta, 2013)

Further studies have analyzed SSP while incorporating a customized alkali/surfactant combination in the aqueous phase of steam. Heavy oil from California's San Joaquin Valley was used in experiments involving NA_2CO_3 alkali and an alpha olefin sulfonate (AOS) surfactant with 16-18 carbon. Shell found the addition of alkali reduced surfactant adsorption through the reservoir rock becoming more negatively charged and the precipitation of divalent ions. Besides preserving costly surfactants, it aided emulsification through greater reduction of the oil/water IFT (Lau, 2012). The improved emulsification generated stronger steam foam than surfactant and steam injection alone. The enhanced mobility control decreased the residual oil saturation and reduced gravity override. Due to their design and the inherent unfavorable mobility ratio of steam versus heavy oil, standard steam floods and CSS commonly experience the heat loss and general efficiency losses as a consequence of gravity override. Though it may require more up front time and financial investment, an effective alkaline-surfactant-steam flood provides significantly better mobility control and the generation of co-surfactants to meaningfully reduce the residual oil saturation (Lau, 2012). Projects particularly susceptible to gravity override see reductions of residual oil saturation of up to 14% using alkali-surfactant-steam flooding versus surfactant-steam injection and 23% less residual oil saturation compared to steam flooding alone. Other factors, such as better propagation of steam foam and alkaline steam foam's higher pressure gradient than normal steam foam, are less well understood but also contribute to reduced residual oil saturation in experiments (Lau, 2012).

5.1.2 Other Chemical-Steam Combinations

Studies on alkaline-surfactant-steam flooding are rare; those focusing on oil of Canada's bitumen viscosity are even less common. The concluding remarks of Shell's 2012 report on the subject, however, suggests SAGD applications in very heavy crude still benefit from alkali-surfactant mixtures by slowing steam breakthrough to the producer, quickening gravity drainage due to the emulsification process, and allowing better control of steam chamber development along lengthy horizontal injector wells (Lau, 2012).

While results consistently demonstrate improved recovery across several crude types, their relative success hinges on the oil's viscosity and acid number as well as the surfactant/alkali mixture. (Zeidani & Gupta, 2013).

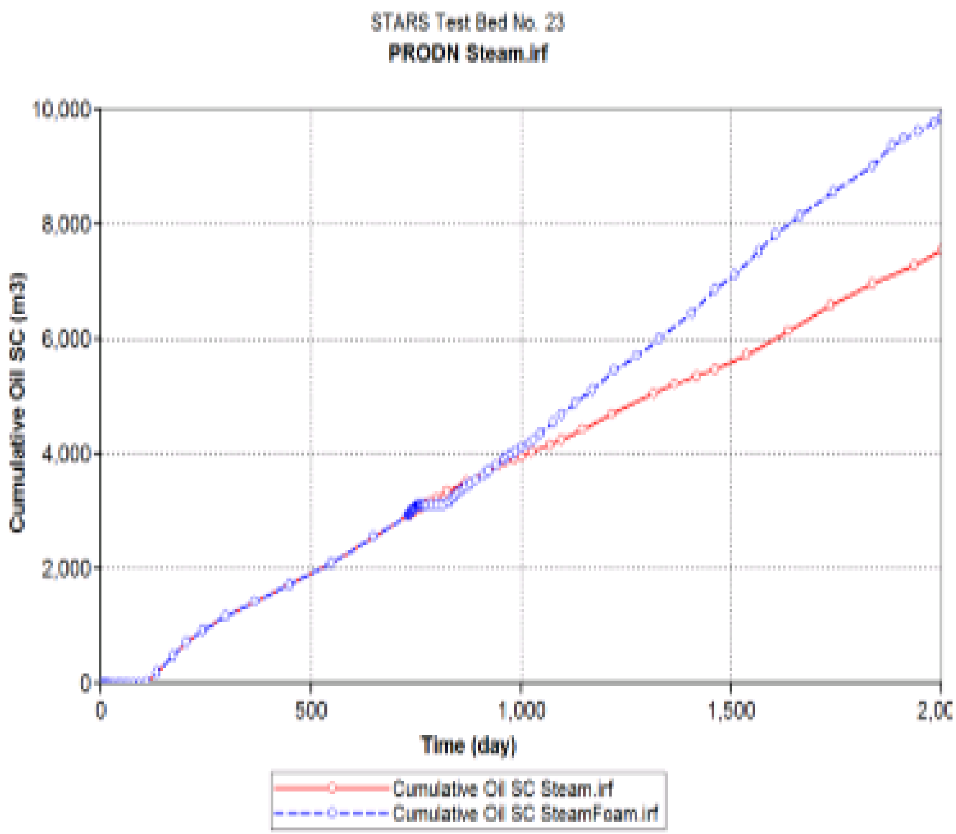
5.1.3 CMG-Stars Reservoir Simulation of SSP

Reservoir simulations using CMG-Stars were performed to estimate incremental recovery through Steam Foam generation compared to standard thermal processes in a complex environment. The reservoir is an unbounded one sixth of a three spot pattern containing high vertical permeability, a horizontal streak near the top of the reservoir, and high water saturation zones near the injection and production wells. The objective is to approximately model a fractured Alberta reservoir susceptible to high levels of steam override under normal CSS operations.

The grid is a radial 9 by 3 cross section employed with a highly compressible formation. The simulation tests adding surfactant injection after two years of standard CSS. An empirical foam modeling approach is employed via modified gas relative permeability curves. The degree of mobility reduction is interpolated as a product of factors obtained from aqueous surfactant concentration in the presence of the oil phase capillary number. Adsorption, surfactant decomposition, and oil partitioning are used to model surfactant transport.

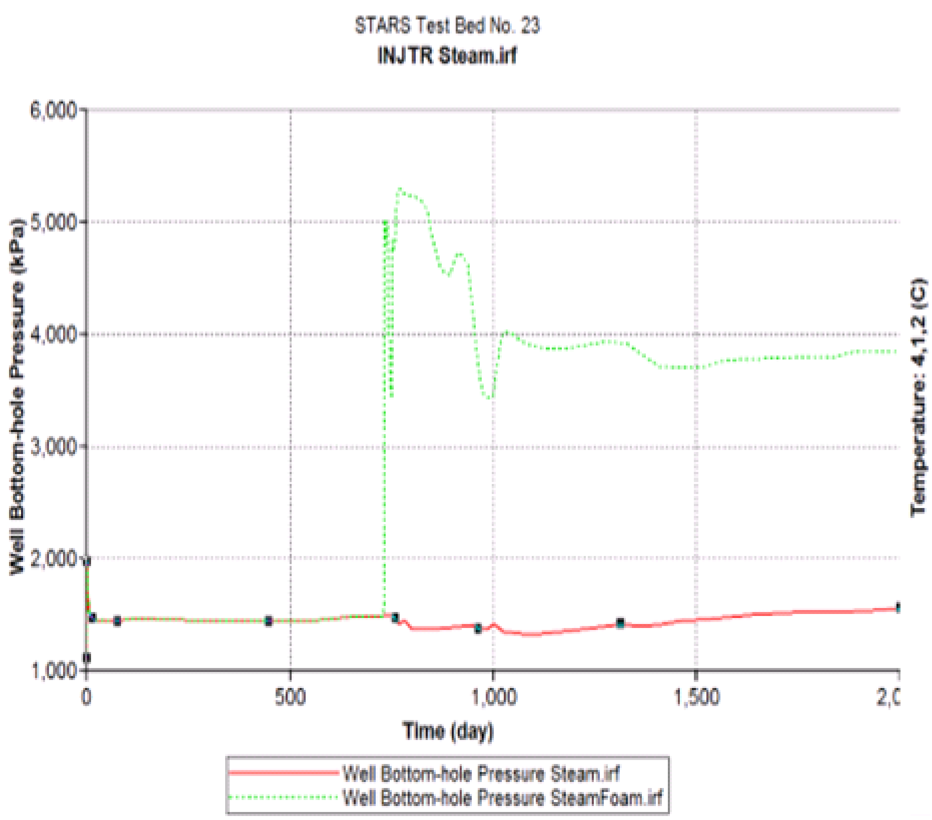
Figure 1 shows oil recoveries keeping all variables constant but initiating injection of 1wt% surfactant at the two year mark. The increase in recovery is immediate and linear through the 2,000 day simulation run.

Figure 1. Surfactant-Steam Injection



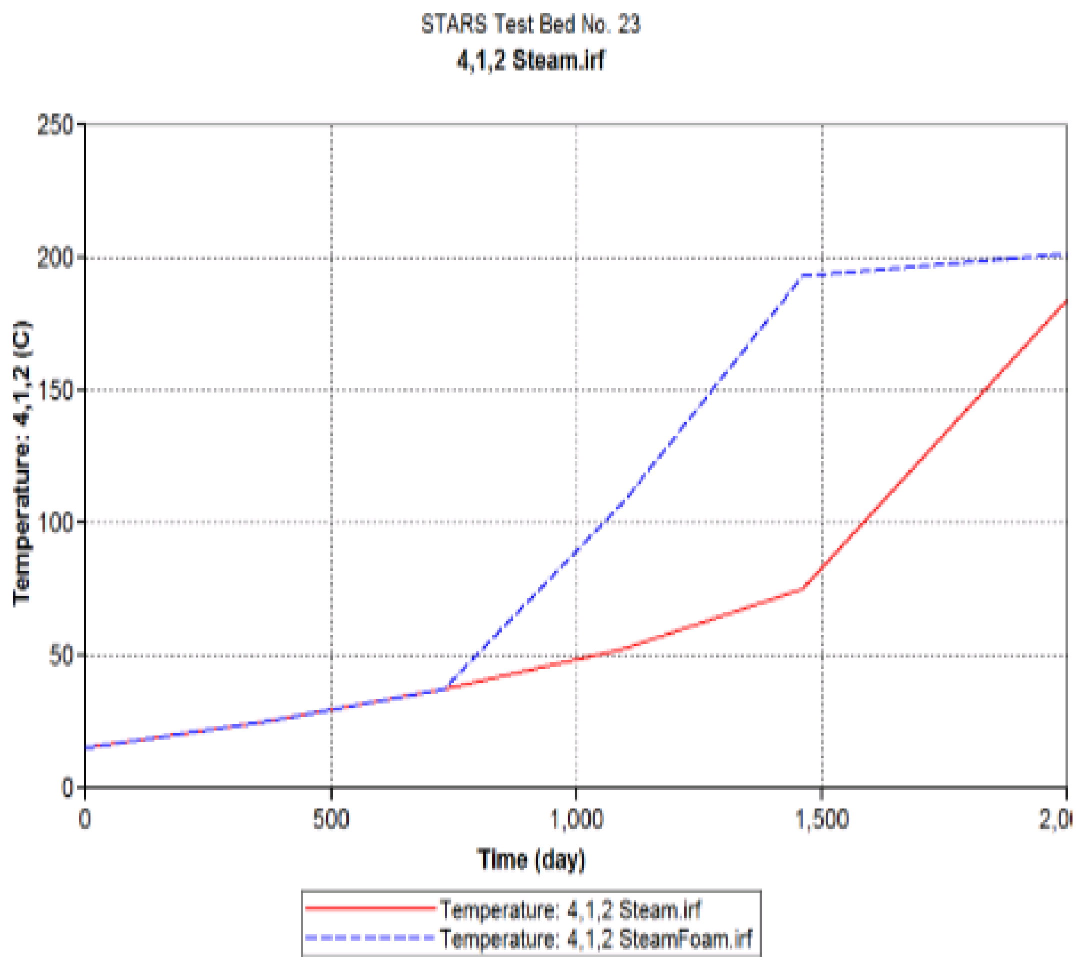
At the end of the run, the addition of surfactant and theoretical generation of steam foam increases recovery by 28% compared to CSS alone. Gravity override decreased notably along with an empirical increase in overall thermodynamic efficiency. In order to determine if steam foam improved the mobility ratio, bottomhole pressure at the injector was measured throughout the simulation run. Steam injection alone maintained 1,500 kilopascals (kPa) while the generation of steam foam at the two year mark instantly raised pressure temporarily to 5,000 kPa. The more viscous steam foam begins to propagate through the reservoir and within 6-9 months bottomhole pressure stabilizes at 2,900 kPa. This coincides with the theoretical improvement in the mobility ratio, decreased gravity override, and enhanced sweep efficiency. These are strictly results from a simplified numerical simulation and while the direction is probably the same in the field, the magnitude will vary greatly.

Figure 2 Bottomhole Pressure Analysis



Another area of interest was impact on heat transfer. Steam foam and its previously mentioned characteristics should benefit system thermodynamics. Instead of using the bottom or top of the reservoir, the 4,1,2 grid block, at 30 m laterally from the well and approximately half way down the well's vertical length, was studied. At this location the steam foam's impacts on heat transfer in the reservoir should be nuanced but still observable. As predicted by the steam's enhanced mobility and improved resistance to gravity override, temperatures in this zone when using surfactant are double that of the base thermal case within 300 days of co-injection.

Figure 3 4,2,1 Grid Block Temperature Comparison



The temperature differential continues to rise steadily until 1,450 days at which co-injection produces temperatures of 190 °C while steam alone is at 80 °C. At this point in time the base case increases rapidly while the steam foam's temperature levels off. Given the injection of surfactant does not cause a net increase in latent heat, it is expected that the two procedures reach the same maximum temperature of 200 °C. It is clear, however, that the co-injection significantly improved heat transfer to this portion of the reservoir and likely contributed to overall increased production rates and improved sweep efficiency. The fact the simulation is designed to model a fractured reservoir particularly susceptible to steam override suggests this large change in thermal flows is more dramatic than would be the case in a standard reservoir.

5.2 Steam and Solvent

Gas and steam projects are another area of hybrid applications. Cenovus developed the Solvent Aided Process (SAP) which is SAGD combined with solvent injection. This process has been tested by the firm since the year 2000 with a pilot test in Christina Lake in 2004. They estimate a 30% production rate improvement, 15% total IOR, 3% reduction in annual fuel gas usage, .05 bbls of butane per bbl bitumen produced, a 10% decrease in annual sustaining capital, 5-10% reduction in non-fuel operating cost, a $1 netback uplift per bbl, at a 30% increase in initial capital versus standard SAGD processes. As previously discussed, steam chamber expansion control is one of the most difficult parts of the process and heat losses occur rapidly once the chamber reaches the overburden and transfers more and more energy to non-producible portions of the reservoir. SAP enables the steam chamber to expand horizontally at a greater rate than standard SAGD. This has the added benefit of being able to produce the same volume of the reservoir with less wells (Energy, 2013). These field results correlate well with the previously discussed lab experiments and the limited number of related pilot tests with published data.

Chapter 6

Engineering Challenges

6.1 Physics

The engineering challenges associated with EOR are numerous. Thermal processes are particularly difficult due to the additional variables of generating and transporting steam effectively to the reservoir. Heat loss is the enemy of an efficient thermal flood. According to an analysis of energy distribution over 15 years by Schoonebeek, on average over-burden and under-burden absorb 30% and 20% of net heat injected into the reservoir respectively. Produced fluids contain about 15%, reservoir rock 20%, and the remaining water and oil in the reservoir retain the remaining 5% of heat (Hornman, Popta, Didraga, & Dijkerman, 2012). High water saturation, especially above .3 (S2φ >0.3), is detrimental to project efficiency and is an important screening criteria. Using hot water instead of high quality steam also degrades efficiency considerably as the latent heat of hot water is much less than high quality steam. Surface losses through pipelines and equipment are generally responsible for 5% or less of total heat loss and are not of major concern for well-designed projects. Evacuating the annulus and high injection rates through insulated tubing mitigate wellbore losses (Javad, Oskouei, Maini, Moore, & Mehta, 2012).

In-situ combustion, as previously discussed, avoids most wellbore and surface losses. As a general reference, at a depth of 1000 m hot water, steam, and hot water but in insulated tubing sustain heat losses of 85%, 40%, and 10% respectively. At the same depth, injection rates of 1350, 2270, and 3178 kg/hr of steam have heat losses of 35%, 20%, and 15% respectively (Wheaton, 1991). As these figures demonstrate, it is critical to perform a cost analysis of the resources required to achieve low heat losses through high quality steam production, insulated tubing, and high injection rates against the cost of generating significantly more steam. From a geological and thermodynamic perspective, thin reservoirs are much more inclined to experience significant heat loss. Low permeability aggravates these issues (Zhao & Gates, 2013). At greater than 280 ft thick, despite the heat injection rate varying from .05 all the way to .6 MMBtu/D/Acre ft, vertical heat losses are generally in the 10-20% range. On the contrary, a reservoir only 100 ft thick ranges from 18% to 40% across the same heat injection rates. High initial oil saturations also ensure heat is absorbed by the target (Petrowiki, 2013).

These variables coincide with the greater thermal efficiency of thicker reservoirs and higher injection rates. In a simulated environment mimicking the a standard heavy oil reservoir, at 90 ft thick and an injection rate of .1 MMBtu/D/Acre ft vertical heat loss as a percentage of input is 40%. Doubling to 180ft thick while maintaining the same injection rate reduces vertical heat losses to 22%. Raising the injection rate to .4 MMBtu/D/Acre ft further lowers vertical heat losses to 15%. Reservoir thickness beyond 160 ft does not notably impact vertical heat losses. In addition, reservoirs with these large pay zones only benefit marginally, usually less than a 10% reduction in heat losses, from raising injection rates from the low end .05 MMBtu/D/Acre ft to the high end of .6 MMBtu/D/Acre ft. On a reservoir only 100 ft thick, the aforementioned increase in injection rate corresponds with vertical heat losses of 45% declining to 20% (Petrowiki, 2013).

The primary measure of heat loss and often overall project efficiency is the steam oil ratio (SOR). A low SOR means more oil is impacted and thus produced per unit of heat injected. As previously mentioned, CSS usually needs 3-8 barrels to produce one barrel of oil while the more precise methods of SAGD lie in the 2-5 range. The value of the SOR is it encompasses the vast majority of project components and is a reliable measure of both project economics and engineering efficiency. An SOR of 2-3 is considered economic in the vast majority of circumstances with top firms maintaining ratios of 1.9-2.4 (Canadian Natural Resources, 2013) (Cenovus Energy, 2013).

The pressures and thermodynamic environments created by thermal applications are much more intense than those naturally found in the formation. These extremes can result in unexpected and powerful changes in the reservoir. Uncontrolled fracturing occurs when steam injection generates pressures surpassing fracture pressure of the reservoir, resulting in vertical or horizontal fractures. Uncontrolled fractures can divert steam flow unexpectedly and compromise project viability. Fractures that impact the cap rock can result in substantial added heat loss. Some degree of fracturing may be necessary, even desirable, if initial injectivity is poor. Fractures are usually horizontal, extremely numerous, and millimeters in height. They allow steam to propagate into the reservoir at an enhanced rate. This beneficial fracturing usually occurs when induced pressure is just at fracture pressure and not significantly above it. Engineers may monitor reservoir pressures carefully and increase steam injection rates until approaching fracture pressure. Only a small and controlled amount of fracturing near the well bore is usually sought after and pressure is reduced upon achieving the preferred injection rate (Jocker & Prioul, 2010). While SAGD customarily injects steam below fracture pressure, CSS and other processes that benefit or depend on creating fractures may regularly exceed the pressure threshold (Munoz, 2013).

Achieving a distributed steam profile through horizontal injection wells is another technical challenge with significant impact on recovery. Although optimizing the frequency and placement of perforations on the injection well is beneficial, steam still has a tendency to enter the reservoir through the first perforations in the well. Instead of an even distribution across the length of the horizontal, steam concentrates among the first perforations with the middle sections receiving less steam than engineers' desire. The end of the well may have more favorable steam output than the middle section (Fram, Sims, Sequera, & Mayer, 2010).

Regardless of the thermal application, understanding the physics and thermal properties of the reservoir rock, oil, and their interactions are critical. Though reservoir rock permeability can vary by several orders of magnitude, the key properties that characterize heat flow; density, heat capacity, and thermal conductivity, do not differ by more than a factor of three. As far as the physical mechanics are concerned, injected steam or hot water displace resident fluids and occupy their pore space. Conduction transfers heat to the rock grains and remaining local resident fluids. Conduction further transfers energy to the unheated portions of the reservoir. As an example of how similar these properties often are, dry sandstone has a bulk density of 2.08 g/cm^3, specific heat of .729 kJ/kg-K, and thermal conductivity of .831 J/s-m-K while dry shale has figures of 2.32 g/cm^3, .761 kJ/kg-K, and .989 J/s-m-K. Oil saturation, porosity, and temperature may vary across the reservoir and all impact the thermal conductivity of local rock. Heat capacity has a weak dependency on temperature; sandstone's C_p Btu/lbm-degree F is .184 at 100 °F and only increases to .244 at 500 °F. This relationship is consistent with most common reservoir rock such as limestone and shale (Issler & Jessop, 2010).

Related to these properties is why steam is superior to hot water. Steam has more energy per unit mass, flows at a higher velocity while dislodging more oil, lower susceptibility to viscous fingering, and the corresponding steam distillation can add a miscibility mechanism hot water cannot (Munoz, 2013).

Heat transport to lower oil viscosity is the crux of thermal EOR. This occurs through three processes; convection, conduction, and to a lesser extent radiation. Convection is the process by which heat is transferred into the reservoir or from one area of the reservoir to another by a flowing fluid. This occurs via an outside mechanism such as steam injection or through natural means due to differences in density. With temperature data on the hot and cold portions of the reservoir, the distance between them, and associated thermal conductivities, Fourier's Law provides a fairly accurate but simplistic means of determining the heat transfer rate in the form of BTU/day. The law is a relationship between heat flux and temperatures gradient which defines the quantity called thermal conductivity. Microscopic environments, those with small distances between regions, transfer heat rapidly while those with large spaces transfer more slowly. For example, hot fluids in a microscopic region come to thermal equilibrium with a porous rock in less than a second while heat flow in a macroscopic environment may be one foot per month. Conduction transfers heat through non-flowing materials by molecular interactions from a region of high temperature to a region of lower temperature until both areas are the same temperature (Leinhard, 2012).

Radiation is via electromagnetic waves primarily through a transparent medium. This is caused by the temperature difference between the ambient and heated surfaces in question. Though usually localized to surface operations such as boilers and tubing, radiation can have a meaningful impact in the reservoir if temperatures exceed 300 °C (Barua, 1991).

6.2 Well Design

Improvements in well technology are a major reason for the growth in thermal projects and their recovery efficiency. The ability to drill long horizontal wells accurately is likely as important for thermal recovery in Canada as it has been for shale development in the United States. EnCana, one of the largest firms involved in bitumen recovery, confirmed in 2012 the drilling of a horizontal well with a lateral length of 12,900 ft; a record for on shore drilling in North America (EnCana, 2013). Advancements in well precision and length continue to augment project economics. As experience drilling lateral wells increases, firms are incorporating methods previously determined impractical or too costly.

Cenovus's newly developed Wedge Well technology is straightforward but effective. In addition to the standard injector and producer horizontal wells in a SAGD process, additional lateral wells are drilled in between and parallel to producing wells. This allows the farthest portions of the steam chambers, often inaccessible to the standard well pair, to also produce oil. Although additional costs are associated with drilling three wells instead of two per SAGD operation (SAGD pairs are in rows therefore one Wedge Well serves the far edges of one well pair's steam chambers), Cenovus records 10-15% improvements in ultimate recovery without injecting additional steam. Cenovus's increasing usage of Wedge Well technology suggests this reduction in the steam oil ratio offsets the supplementary well’s cost. Increased oil prices and or decreased drilling costs make this technology more valuable and cost effective (Cenovus Energy, 2013).

6.3 Heat Generation and Transfer

Steam generation efficiency and reliability is extremely critical for a technically and financially successful project. This sub system of the EOR operation requires careful planning and monitoring. Most projects in Canada generate steam from boilers powered by natural gas. This is currently the most economical method when available (Canadian Natural Resources, 2013). Supply reliability and sensitivity to commodity prices can be challenges. Heavy oils such as those produced by most thermal processes have little or no gas co-production; thus natural gas must be supplied by external means and transmission disruptions halt oil production. Natural gas production from conventional oil reservoirs in the Athabasca region are insufficient to meet EOR demand so it must travel through extensive pipeline networks. For Canadian projects not using natural gas, steam may be created from burning the produced oil at 2-3 times the commodity cost and 30% more carbon dioxide emissions than burning natural gas. In low pressure environments, one barrel of oil can generate 16 bbls of steam in cold water equivalent (CWE) while one barrel generates 12 bbls in higher pressure settings. Thermal efficiency is 70-80% but still equates to 20-30% of produced oil consumed as fuel. Net oil steam ratio (net OSR) assumes a .06-.08 reduction to compensate for using oil as fuel (Padmanabhan & Amin, 2005).

Another option for steam generation is solar thermal enhanced oil recovery. This technique uses solar arrays to concentrate the sun’s energy to heat water and generate steam. Solar is able to create the same quality steam as natural gas boilers with temperatures of 400 °C and 1,500 psi. An initial concern for this technology was the high variability in steam production. Several large oil producers, however, have not found injecting steam only during daylight hours as problematic. For projects with high sensitivity to variable injection rates, it is likely solar could still provide 40-60% of energy needs with natural gas used during night time and inclement weather. Where pipeline infrastructure costs seem insurmountable, otherwise expensive solar energy may be cost effective (Goosseens, 2011).

Similar to utility style arrays, the two primary methods used are the central tower and enclosed trough. Central tower uses a field of large tracking mirrors to concentrate the sun light on a boiler. Enclosed trough architecture holds the solar thermal system within a glasshouse to protect it from the elements. Curved reflecting mirrors are suspended within the glasshouse as a single-axis tracking system repositions the mirrors to the position for optimal reflection. Water is carried through steel tubes tracking through the glasshouse and is the targets of the reflected energy. Steam is generated when sun radiation is sufficiently powerful. A benefit to this method is these same steel pipes are connected to the reservoir and the steam is fed directly into it. Chevron was able to generate steam for a thermal EOR project for $4 per million BTU compared to $10 for conventional solar (Goosseens, 2011). Solar EOR is still relatively new with the first commercial project deployed in February of 2011 by Barry Petroleum, California's largest independent oil producer. It generates one million BTU's per hour and was constructed in only six weeks. Chevron and BrightSource Energy developed a 29-megawatt solar to steam facility in Fresno County, California. Consisting of 3,822 mirror systems, the project ran significantly over budget and has resulted in BrightSource suffering at least $40 million in losses and rising (Gilbert, 2011).

Although there is some promise to solar power for steam generation, geography plays a major role and to the detriment of its potential in Canada. The Persian Gulf and California, for example, are within the ideal latitudes of 15° and 35° N. Semi-arid locations also benefit with reduced humidity and consequently cloud cover and typically receive more solar radiation. The least favorable area for solar is beyond 45° N where half of all radiation is diffused and cloud cover is frequent. 99% of Canada and all its areas of notable hydrocarbon reserves are in this belt (National Renewable Energy Laboratory, 2013). Short of dramatic changes in environmental regulations, which would likely negatively impact thermal oil recovery in general, or massive increases in solar steam generation efficiency, it is unlikely solar EOR will have a major impact in Canada. It is possible, however, that isolated projects without natural gas infrastructure might benefit from considering solar or at least solar assisted steam production.

6.4 Process Selection and Testing

Given the complex physics involved, choosing the appropriate EOR methodology and project design is not an easy task. For EOR processes applied in the mature stages of a reservoir's lifespan, most reservoir properties such as pore morphology and heterogeneity are well defined. Regardless, stages of evaluations, be it at log scale, interwell scale, or field wide, reduce uncertainty about economic and production success. The crude's characteristics alone, particularly oil API gravity, quickly narrow suitable EOR techniques as outlined in each methodology's individual sections. The low API gravity crude within most of Athabasca, Cold Lake, and Peace River require thermal applications from project onset (Butler, 1991). After preliminary analysis dictates a particular process, the evaluation moves into the laboratory as potential benefits and negative externalities are identified. Estimated viscosity reduction and other positive attributes should be considered against the possibility of wax dropout or exceedingly low pH produced fluids. Given sufficient field history and characteristics analysis, geoscientists and engineers form static and dynamic reservoir models. Flow rate, expected temperatures, injectivity, and other variables ascertained from laboratory tests contribute to the model's accuracy. Simulation alone cannot guarantee project success but paired with highly accurate crude and reservoir data, it can represent a useful feasibility test and give reasonable estimates for both the range of ultimate OOIP recovered and the associated production rates (Xia & Greaves, 2001). It's critical to consider a single unknown, such as unaccounted for heterogeneity, can fundamentally alter production versus the simulation. If simulations provide sufficient economic potential, the next steps are field pilots. These pilots should attempt to answer specific questions or concerns; particularly those that lab tests and simulations could not validate or take into account with sufficient confidence.

Often, a pilot test evaluates one of the following parameters: recovery efficiency, effects of reservoir geology, reduce technical uncertainty about a specific variable, recover additional data to calibrate simulation, test different options, or refine operation strategy before going full-scale. If injectivity is the primary concern, a single vertical well may be all that is required. If the optimum distance between parallel lateral wells or general sweep efficiency are of concern, a significant investment of multiple wells and years of testing may be required before uncertainty is reduced to move forward with full scale production. Using Exxon Mobile as an example, a 2009 list of 20 EOR projects stated only one's pilot testing finished within a year with several lasting longer than three years. (Morris, 2010 see also Schlumberger, 2011).

Chapter 7

Economics

7.1 Aggregate EOR Value

While EOR was only responsible for approximately 4% of 2012 global production of thirty two billion barrels, it still represents over a billion barrels annually and is an extremely critical tool within the oil sector's portfolio for replacing the 100 billion barrel giant fields the world no longer discoverers with regularity. In fact, the Canadian oil sands and the various shale formations in the United States, Argentina, and elsewhere, are arguably the only significant new oil field discoveries in the last two decades and neither are conventional reservoir types producible through standard processes (World Energy Council, 2013). Legacy fields are generally in decline with average production histories exceeding forty years. The probability of discovering additional giant fields of conventional crude with normal accessibility, particularly onshore, is low. The aggregate market value of EOR rose from $3.1 billion in 2005 to over $100 billion in 2012 (SBI Energy). Using $115/bbl, the U.S. Department of Energy estimates the 2015 EOR market value at two trillion dollars. Most of this increase is due to the rapid expansion of Canadian heavy oil projects. Minor increases in production efficiency and or expanding the profile of reservoirs deemed compatible for EOR could change this figure dramatically. The Department of Energy expects EOR to be worth at least 500 billion in 2015 even with an oil price of $55/bbl (Department of Energy, 2013).

7.2 Present Day and Future Production Rates

The significance of EOR applications in Canada is exemplified by its associated production. Canada's oil sands are reaching two million barrels per day of which about 50-55% is surface mining. This output is expected to be 2.2 million barrels per day provided sufficient demand, distribution infrastructure, and economics by 2015 (Government of Alberta, 2013). Alberta's government estimates 3.5 Mbbl/d by 2020 with the potential of 5 Mbbl/d by 2030 provided adequate investment and market demand. The Canadian Association of Petroleum Producers states similar figures (Canadian Association of Petroleum Producers, 2013). CSS produces at least 250,000 barrels a day with SAGD projects responsible for another 200,000. In December 2007, ConocoPhillips announced its intention to increase its oil sands production from 60,000 barrels per day (9,500 m^3/d) to 1 million barrels per day (160,000 m^3/d) over the next 20 years, which would make it the largest private sector oil sands producer in the world. ConocoPhillips currently holds the largest position in the Canadian oil sands with over 1 million acres (4,000 km^2) under lease. Other major oil sands producers planning to increase their production include Royal Dutch Shell (to 770,000 bbl/d (122,000 m^3/d)); Syncrude Canada (to 550,000 bbl/d (87,000 m^3/d)); Suncor Energy (to 500,000 bbl/d (79,000 m^3/d)) and Canadian Natural Resources (to 500,000 bbl/d (79,000 m^3/d)). If all these plans come to fruition, these five companies will be producing over 3.3 Mbbl/d (520,000 m^3/d) of oil from oil sands by 2028. (Franklin & Gismatullin, 2012; see also Dutta, 2012).

7.3 Oil Price Thresholds

As important as recovery rates and portion of OOIP firms are able to produce, supply costs for the oil sands are significantly lower than when projects went online in the early 2000’s. As early as 10 years ago, projects often needed $80/bbl to ensure economic viability; several new projects are economically feasible at half that figure (Cenovus Energy, 2013; see also Canadian Natural Resources, 2013). Given reserves by definition are reliant on economic circumstances, both in terms of produced hydrocarbons’ value and the cost of inputs, primarily infrastructure and labor, lowering the cost of complex thermal projects will increase the financial attractiveness of Canadian reserves and attract investment. Operating costs range from $5-15/bbl for bitumen and $12-18/bbl for synthetic crude oil; supply costs range from $10-20/bbl for bitumen and $22-28/bbl for synthetic crude oil (National Energy Board of Canada, 2013).

7.4 Local Economic Impact

The economic impact of heavy oil production in Canada is considerable. Cumulative investment from 2002 through 2012 surpassed $100 billion with an additional $350 to $400 billion in price-adjusted investment planned through 2035. These investments represent 3.2 million person-years of employment in Canada including domestic supply chain effects which make up approximately 40% of the figure. Though focused in Alberta, Ontario receives significant employment opportunity benefits followed by British Columbia and Quebec. Oilfield services, professional services, manufacturing, wholesale trade, financial services, and transportation are the sectors with the greatest gains in employment in that order. 30% of domestic inputs are sourced outside of Alberta distributing direct economic benefits. $172 billion in wages and salaries are expected from direct and supply chain employment effects generating a substantial income effect as these monies are spent and invested. It is worth noting, however, at least one in seven direct workers, those working on site, assisting in oil and gas production, and construction, for instance, lives outside of the province they work in. The vast majority still reside elsewhere in Canada with the remaining fraction primarily composed of U.S. citizens. This remittance effect is often greater than supply chain effects in areas like Newfoundland and Labrador where oil and gas activities are minimal but are the home provinces of many workers (The Conference Board of Canada, 2012).

Oil sands investment augments the fiscal environment across Canada. Between 2012 and 2035, related investment is expected to generate $45 billion in federal and $34 billion in inflation-adjusted provincial government revenues and includes effects related to personal income taxes, corporate taxes, and indirect taxes such as fuel taxes. 76.9% or $26.3 billion of provincial revenues are expected to go to Alberta while federal government transfers are closer to mirroring a per capita distribution (The Conference Board of Canada, 2012).

From 2009 to 2012, 32% of investment in Canada's oil and gas sector is foreign. China's role has grown, along with Europe to a lesser extent, while U.S. importance has subsided. The 2012 bid by China's National Oil Offshore Corporation (CNOOC) to purchase Nexen is recent example of large foreign direct investment (FDI). Canada's growing expertise in heavy oil development has increased outward FDI to a record high in 2011. Although still a net importer of oil and gas equipment, the nation's exports of pumps and compressors have increased dramatically since the late 2000's. The U.S. supplies over half of Canadian imports for almost all oil sands related manufacturing goods. The Alberta government estimates 192,000 person-years of manufacturing employment in the U.S. due to oil sands development and associated activities (The Conference Board of Canada, 2012).

To put this level of investment into context, it is expected to surpass that of the Three Gorges Dam; which is not only the largest dam ever constructed but also the largest power station (Chinese National Committee on Large Dams, 2011). Given Canada's stable government and vast resource base, the key constraints to development are moving sufficient equipment and trained personnel into the region while establishing the means to transport oil out.

7.5 Environmental Challenges

Managing the negative externalities of oil production in Canada is critical to its long term viability and reception by some international markets. The environmental impact of EOR projects, especially thermal, takes many forms and is often difficult to measure. The ability to monitor and mitigate emissions is an acute need to growing EOR's market share. Steam generation in of itself is very energy intensive; whether natural gas, oil, or gasified asphaltines is the source.

7.5.1 Air Pollution

The EPA estimates 1672 lbs/MWh of CO2, 12 lbs/MWH of sulfer dioxide, and 4 lbs/MWh of nitrogen oxides for consuming oil for electricity versus 1135 lbs/MWh of

CO2, .1 lbs/MWh of sulfer dioxide, and 1.7 lbs/MWh of nitrogen oxides for natural gas. On-site boilers used for EOR projects usually have lower efficiencies than utility scale versions the EPA references. Depending on thermal efficiency and reservoir characteristics, MCF of natural gas per barrel of produced oil ranges from .82 to 1.92 as the wet steam to oil ratio varies from a more efficient 2.5 to 6.0. (McColl, Mei, Millington, & Kumar, 2008; see also Brandt, 2011)

Outside of air pollution, which is estimated at 10-15% higher on average for all Canadian heavy oil projects versus conventional production, water pollution can be a significant though avoidable issue with vigilant operational management. In 1997, Suncor admitted to leaking 1,600 square meters of compromised water into the Athabasca River. The corresponding delta is the largest freshwater delta in the world but the impact of pollution over time can still be material. The natural toxicants derived from bitumen are arsenic, cadmium, chromium, lead, mercury, and nickel, among others (McColl, Mei, Millington, & Kumar, 2008).

The oil sands industry has taken several measures to reduce emissions such as cogeneration of steam and electricity, leak detection programs for natural gas infrastructure, reduction of methane emissions from natural gas dehydrators, vent gas capture and storage, power generation with micro-turbines, and ever increasing efficiency of the various pumps, compressors, et cetera, in site operations. The contribution is significant on a longer term basis; the National Energy Board of Canada estimates a 53% reduction in CO_2 emissions per barrel from 1990 to 2010. In 2010, all oil sands operations, including upgrading, contributed to 38.2% of Alberta's greenhouse gas emissions and 6.8% of Canada's total (Government of Alberta, 2013).

Though unintuitive, oil sands in-situ extraction, with projects often requiring the injection of hundreds of thousands of barrels of steam and the associated combustion of millions of cubic feet of natural gas, has not generated on average more lifecycle greenhouse gas emissions than surface extraction and the accompanying upgrading process. The Government of Alberta in 2010 assessed 15.3% of greenhouse gas emissions to in situ methods and 22.9% to oil sands mining and upgrading despite the same production from each. The aforementioned THAI process that switches from steam injection to in-situ combustion could alleviate demand for natural gas and water, subsequently decreasing the negative externalities of burning and transporting billions of cubic ft of natural gas annually. Industry is unsure what portion of bitumen deposits are suitable for THAI like processes but proponents suggest at least a low double digit percentage (Castrogiovanni & Ware, 2011). Local air pollution has been monitored since 1995 and the oil sands region shows no change in the long term air quality of carbon monoxide, nitrogen dioxide, ozone, fine particulate matter, and sulfur dioxide. Intermittent increases of hydrogen sulphide, a pollutant common to oil refineries and upgrading centers, have been reported in the Fort McMurray area but are not statistically significant according the Government of Alberta (Government of Alberta, 2013).

The Natural Resources Defense Council (NRDC), on the contrary, estimates all elements of turning raw earth into usable end products, including physical extraction, processing bitumen into crude oil then a consumable product, transport, and finally reclaiming the land results in three times the global warming pollution of similar processes for conventional production (Natural Resources Defense Council, 2012). The World Resources Institute estimates increased lifecycle greenhouse gas emissions of 15% to 50% depending on if surface extraction or steam based methods is used (Demerse, 2011). The European Union assesses extra carbon emissions from oil sands crude at 12% higher and greenhouse gas rating 22% greater than conventional (Lewis, Ljunggren, & Jones, 2012). The variance in methodologies included in emissions calculations clearly yield differing results.

7.5.2 Land Management

Land management is also a concern but more so for surface extraction than in-situ procedures. Never the less, even when utilizing several wells from one pad and long horizontal wells that minimize surface disturbances, many forms of steam injection require multiple wells per application and the sizeable infrastructure necessary to generate and transport steam. Pipelines are required to transport natural gas or other fuel types used to generate steam. Based on the Government of Alberta's most recent figures, 715 of Aberta's Boreal Forest's 381,000 square kilometers have been disturbed by mining activities. To ensure reclamation takes place independent of a company's future financial health, mine operators are required to supply security bonds prior to receiving final project approval. Alberta held in excess of $875 million in security bonds as of March 31, 2012. Per the most recent government data, only 71 square kilometers have been or in the process of being reclaimed and thus uncertainty surrounds its effectiveness (Government of Alberta, 2013). Given much of the land disturbance from surface extraction is similar to that of the coal industry, it is likely the reclamation process will be as well.

7.5.3 Water Utilization and Contamination

By its nature, large amounts of usually fresh water are required for long periods of time to satisfy the needs of thermal projects. Water issues are not as commonly discussed as air emissions but are still a significant issue the industry faces long term and deals with on an on-going basis. Recycling of water to generate steam is becoming more commonplace as is using brackish water from underground aquifers instead of surface fresh water. The latter come at the expense of equipment degradation and additional complexity. Technologies leveraging solvents and gas injection in replace of or in conjunction with standard steam injection lower overall water usage. As is the case with developing shale formations through hydraulic fracturing or any other process involving injecting and producing large amounts of water, properly dealing with mine tailings is critical. Canada benefits from a low population density, sparse habitation near most large hydrocarbon deposits, and plentiful fresh water resources. To put the oil sector's water consumption into context, oil companies have licenses to use about 1% of the Athabasca River that travels through the region and is what it was named after. Actual consumption is .4% of annual flow (National Energy Board of Canada, 2006). If production targets are met this would likely increase to 2.5% of the river's flow. The province of Alberta does restrict diverting more than 1.3% of the river's flow under low river conditions which would necessitate increased recycling or decreasing oil sector activity when production reaches the 2.5-3.5 million bbl/d that correlates with that limit. All oil sands operations use approximately 350 million cubic meters of water annually according to Greenpeace; this is about twice the volume of the city of Calgary. SAGD recycles 90-95% of water and an average of .2 volumes units of water is used per volume unit of bitumen produced. This is compared to 2 to 4.5 volume units of water for mining and other surface operations. As SAGD's share of production grows, it is feasible that even against significant growth in overall Canadian oil production water usage could remain steady or even decline (National Energy Board of Canada, 2006).

Chapter 8

Conclusion

8.1 Macroeconomic Energy Analysis

Canadian and Venezuelan heavy oil deposits are currently positioned to be key contributors to meeting the expected 40% rise in global energy consumption from 2009 to 2035. Demand for renewables is supposed to increase faster than conventional fossil fuels but their share is expected to be below that of any single fossil fuel. Oil consumption will increase significantly on a gross basis but estimated to fall from 33% to 27% of total energy consumption through 2035. The outlook for oil prices above the economic limit for most Canadian heavy oil projects is difficult to ascertain but appears to be positive. Crude futures as of November 2013 remain above $80/bbl through the December 2018 contract; the market is too illiquid beyond this to be overly informative (CME Group, 2013). These prices bode well for even more costly EOR processes.

Increased reliance on production from off shore and unconventional methods, such as hydraulic fracturing and enhanced oil recovery, require much higher capital expenditures and complex processes than conventional sources. This dependency, especially if it grows over time as predicted, suggests oil prices will remain above the $45 to $65 bbl required for the majority of thermal heavy oil projects. Within the Middle East, Saudi Arabia, Iraq, and Iran have capacity to increase production. Saudi Arabia is expected to increase output toward 12-14 million bbls/d by 2035 though with heavy reliance on the aging Ghawar field. A lack of transparency in reservoir and operationally characteristics combined with the field's very long production history has raised doubts internationally regarding this figure's attainability. Of Iraq's 80 discovered oil fields, 50 have not produced any oil and large areas of the nation's geology remain unexplored. Iran is thought to be able to increase production by at least another 1 million bbs/d but is sensitive to the current political environment and status of international embargos. While OPEC is still expected to produce half of the expected increase in crude demand, mostly by developing nations in Asia and Africa, Canada and, as of more recently the U.S., will play major roles (U.S. Energy Information Administration, 2013).

8.2 Crude Price Differentials

There are areas of concern for Canadian producers even if oil prices remain at $100/bbl. Infrastructure development, primarily pipelines, needs to expand rapidly if additional production can reach refineries efficiently. The Keystone XL pipeline and other projects aim to bring more crude from large storage and producing areas, such as in Cushing, OK, to underutilized hubs along the Gulf Coast and in the Midwest. Unexpected gains in production from shale plays in North Dakota, Colorado, Wyoming, Texas, and other areas compete for pipeline capacity with Canadian output. This situation will be aggravated as Canadian and domestic shale production grows (National Energy Board, 2009).

In addition to but related to the capacity issue is the fluctuating discount Canadian crude receives versus WTI. Synthetic crude oil from Canada suffered a $13 per barrel discount to WTI in early 2012. Western Canadian Select (WCS) is at an even greater disparity, with discounts reaching as high as $30 per barrel versus WTI in mid 2012 (CME Group, 2013). Given certain Canadian crudes such a SCO have traded at premiums to WTI in the past, it is likely further infrastructure development and exploration of new markets, such as terminals to China, will alleviate most of these issues. Depressed premiums for several years, however, could negatively impact investment (The Conference Board of Canada, 2012).

8.3 EOR Investment Level Analysis

Several trends such as sustained high oil prices and technological advancements encourage the development of additional EOR projects. Even considering the domestic shale revolution and its potential overseas, such as Argentina's Vaca Muerta formation, majors around the world are scrambling to replace proven reserves and are forced to engage more challenging and higher risk political and physical environments (Gold & Angel, 2011). The appeal of investment in mature fields of stable markets such as the U.S. and Canada improves with EOR technologies' economics and the increased costs of developing deep off shore and in especially harsh terrain such as the arctic. North America also benefits from reduced geopolitical risk, predictable tax and legal regimes, and extensive reservoir and geological data. Exxon Mobil, the world's largest non-state owned oil company, is expecting greater capital expenditures for less production growth going forward than it has in the past (Kahn, 2012). As its efficiencies continue to improve, firms are incentivized to allocate resources toward EOR in North America and away from cumbersome and often unreliable agreements with Russia or Iraq. This is further exacerbated by the rising cost of many areas of conventional development. Even including the arctic, the majority of conventional plays expected to come online are off shore. The Jack 2 offshore oil rig discovered the largest new conventional play in U.S. territories with 3-15 billion barrels of possibly recoverable resources. This well, however, was drilled through 7,000 ft of water and another 20,000 ft of rock. A joint venture between several of the world's largest oil firms, it is unclear what oil price is necessary to make the project economical or what unknown risks or challenges are involved with producing through a 5.3 mile deep well (Klump, 2013).

A greater focus on the reservoir lifecycle bodes well for EOR. Engineers may determine to skip water flooding and move toward an EOR process as soon as pressure maintenance becomes a concern in the quest for producing the maximum percentage of OOIP. Instead of cumulative recovery of 20-33% of OOIP as has been the case historically, factors such as reserve replacement and higher sustained oil prices incentivize firms to consider all-encompassing approaches with the objective to produce 40-60% or more of OOIP. This has more recently taken the form of exploratory companies selling off assets to other oil companies specializing in developing mature fields.

8.4 Estimated Ultimate Recovery

SAGD and other thermal processes are proven technically and economically successful on a variety of reservoirs. THAI, SAP, VAPEX, and other processes, often with potential to be used in conjunction with SAGD, should raise average recovery rates by an additional 5-25% on top of the already high 50-60% of OOIP produced through SAGD alone. These findings are confirmed with the reservoir simulations performed by scientists internationally as well as myself using CMG-Stars.

Drilling improvements, Wedge Well technology being one example, combined with solvent or surfactant steam hybrid techniques raise average in situ recovery rates by an additional 25-45% of OOIP based strictly on the field data and pilot tests surveyed. Oil prices permitting, this expertise, while still needing to permeate the industry and not applicable to all reservoirs, is a reliable way to grow Canada's reserves by tens of billions of barrels. Estimates of in-situ Canadian oil sands reserves vary from 135 to 164 billion barrels. Using this range and the abovementioned spectrum of recovery rates, overall reserves conservatively grow from 180 billion to 214-254 billion barrels. These figures reflect only an increased recovery rate on reservoirs already deemed economically viable.

Technological and operational progress also make a portion of thinner, more heterogeneous, and less favorable formations in general financially viable. Determining the extent of reserves expansion due to the multitude of previously analyzed developments is an inexact, complex task beyond the scope of this document. Given the sheer scale of the oil sands, however, a conservative 1-3% associated increase in exploitable resources correlates with 16-48 billion incremental barrels (Ernst and Young, 2013). This raises ultimate recovery from Canada's oil sands to approximately 230-262 billion barrels. These figures are estimates but based on aggregating in depth results from leading oil and gas firms' technology presentations and quarterly financial results, numerous government agencies across the U.S and Canada, as well as dozens of technical reports published by organizations such as the Society of Petroleum Engineers covering the spectrum of EOR.

Uncertainty remains regarding long term oil demand, infrastructure development across North America, and the environmental issues associated with oil sands' production. If the past is a reliable gauge, however, the billions in investment from oil and gas firms coupled with responsible management by Canadian agencies will continue to enhance recovery rates and project economics while alleviating environmental concerns.

Appendix A.

Glossary of Abbreviations, Symbols, and Terms

km: kilometers
kW: kilowatts
m: meters
md: millidarcies
Tcf: trillion cubic feet
ft: foot
sq ft: square foot
kPa: kilopascals
cP: centipoise
psi: pounds per square inch
°C: celsius
°F: Fahrenheit
wt%: weight percentage
ppm: parts per million
CO_2: Carbon dioxide
KOH: Potassium hydroxide
kg: kilogram
BTU: British thermal unit
Bbl: barrel
EOR: Enhanced oil recovery
DOE: United States Department of Energy
HCPV: Hydrocarbon pore volume
PV: Pore volume
IOR: Incremental Oil Recovery
ASP: Alkaline-Surfactant-Polymer
CSS: Cyclic Steam Stimulation
SSP: Surfactant-Steam-Process
SAGD: Steam Assisted Gravity Drainage
COGD: Combustion Overhead Gravity Drainage
CHOPS: Cold Heavy Oil Production with Sand
OOIP: Original Oil In Place
VAPEX: Vaporized Extraction
WAG: Water Alternating Gas

Appendix B.

Steam Foam DAT File

```
****************************************************************************
** THIS MODEL HAS BEEN BUILT BY UT-AUSTIN TO COMPAR RESULTS WITH UTCHEM   **
****************************************************************************
*************************************************************************************
**                                                    **
** FILE :  STEAMFOAM.DAT                                             **
**                                                    **
** MODEL:  FOAM MODELLED AS GAS PERMEABILITY REDUCTION       9X1X3 RADIAL GRID
**
**        FOAM SENSITIVITY TO SURFACTANT AND OIL          SI UNITS             **
**        STRENGTH  OF FOAM IS REGION DEPENDENT           ADSORPTION EFFECTS     **
**                                                    **
** USAGE:  SIMPLE STEAM FOAM FIELD MODEL ILLUSTATING MULTIPLE FOAM
CAPABILITIES     **
**                                                    **
***********************************************************************************
**  ==============  INPUT/OUTPUT CONTROL  =====================
RESULTS SIMULATOR STARS
*INTERRUPT *STOP
*TITLE1 'STARS Test Bed No. 23'
*TITLE2 'Steam History Match & Foam Forecast'
*INUNIT  *SI  *EXCEPT 6 1  ** darcy instead of millidarcy
*OUTPRN *GRID *PRES *SW *SG *SO *TEMP *OBHLOSS *KRG *KRO *KRW
          *ADSORP *KRINTER *CAPN *VISO
          *MOLFR *ADSPCMP  ** special adsorption component (mole fr)
          *PPM   *RLPMCMP  ** special rel perm component (in ppm)

*OUTPRN *WELL ALL
*OUTPRN *ITER *NEWTON

*WRST 300
*WPRN *GRID 300
*WPRN *ITER 1

*OUTSRF GRID  *PRES *SW *SO *SG *TEMP *ADSORP
          *MOLFR *ADSPCMP  ** special adsorption component (mole fr)
          *PPM   *RLPMCMP  ** special rel perm component (in ppm)

**  ==============  GRID AND RESERVOIR DEFINITION  =================
*GRID *RADIAL 9 1 3  *RW 0.0   ** Two-dimensional radial crossection grid
                    ** Zero inner radius matches previous treatment

*DI *IVAR 2 8 14 14 8 2 8 14 500
*DJ *CON 60
*DK *CON 15.0
```

```
**DJ *CON 0.3333  *DK *CON 15.0
*POR *CON 0.35
*PERMI *CON 1           ** Standard bed permeability
  *MOD 1  1 1:2 =  10   ** Higher perm commumication path
      6  1 1:2 =  10   ** Higher perm commumication path
    1:9  1   3 =  10   ** Higher perm commumication path
*PERMJ *EQUALSI
*PERMK *EQUALSI
*END-GRID
*PRPOR 1200.0
*CPOR 1E-5
*CTPOR 3.84E-5
*ROCKCP 2.347E+6
*THCONR 1.495E+5
*THCONW 5.35E+4
*THCONO 1.15E+4
*THCONG 4.5E+3
*HLOSSPROP  *OVERBUR 2.347E+6 1.495E+5  *UNDERBUR 2.347E+6 1.495E+5
*HLOSST 15.5
**  =============  FLUID DEFINITIONS  =====================
*MODEL 3 3 3 2   ** Two aqueous and a dead oil components
*COMPNAME  'WATER' 'SURFACT'  'BITUMEN'
**          -----   --------   --------
*CMM        0.0182     0.480     0.500
*MOLDEN       0.0      2020      2020
*CP            0      4e-6      4e-6
*CT1           0      4e-4      4e-4
*CT2           0    1.6e-7    1.6e-7
*PCRIT      21760      1100      1100
*TCRIT      371.0     494.0     494.0

*CPG1       0        125.6     125.6
*CPG2       0            0         0
*CPL1       0       1047.0    1047.0
*CPL2       0            0         0
*HVAPR      0       5500.0    5500.0

*SOLID_DEN 'SURFACT' 23040 0 0  ** Mass density based on 48000 gmole/m3
*SOLID_CP 'SURFACT' 17 0

*VISCTABLE
**    Temp
  10.00000    0.0   1.00000  3.0000E+6
  23.90000    0.0   1.00000  1.5000E+6
  37.80000    0.0   1.00000    30000.0
  65.60000    0.0   1.00000   2000.000
  93.30000    0.0   1.00000    300.000
   121.000    0.0   1.00000   87.00000
   148.900    0.0   1.00000   31.00000
   204.400    0.0   1.00000    9.00000
   260.000    0.0   1.00000    4.30000
```

```
  315.600    0.0   1.00000    2.90000

**  Gas/liq K values  are defaulted correlation
**  Liq/liq K values  are entered as tables
*LIQLIQKV
*KVTABLIM 100.0 8000.0  15 550
*KVTABLE 'WATER'
   0    0
   0    0
*KVTABLE 'SURFACT'
  .2   .2
  .2   .2
*KVTABLE  'BITUMEN'
   0    0
   0    0

** Reference conditions
*PRSR 100.0
*TEMR 15.5
*PSURF 100.0
*TSURF 15.5

**  reaction describes surfactant decomposition
**  first order decay rate is assumed (valid for basic pH)

*STOREAC    0           1        0
*STOPROD    26.37        0        0
*RPHASE     0           1        0
*RORDER     0           1        0
*FREQFAC  34.7
*EACT 32500
*RENTH 0
*O2CONC
*ROCKFLUID

**  ==============  ROCK-FLUID PROPERTIES  ======================
**  This simulation incorporates foam mobility reduction in
**  relative permeability effects which are region dependent.
**  ----------------------------------------------------------------

*KRTYPE *CON       1   ** Standard bed permeability
  *MOD 1  1 1:2 =  2   ** Higher perm commumication path
     6  1 1:2 =  2   ** Higher perm commumication path
    1:9  1   3 =  2   ** Higher perm commumication path

*RPT 1    ** First rock type for standard permeability zones
**  ----------------------------------------------------------------
**  Interpolation between 3 sets: zero, weak and strong foam curves
**  Capillary number calculation is based on aqueous SURFACT IFT
**  specified at 2 temperatures and 2 SURFACT concentrations.
```

```
*INTCOMP 'SURFACT' *WATER
*INTLIN

*IFTTABLE    ** aq mole frac      IFT
    *TEMP  10.0
               0.0           13.
               0.3           13.
    *TEMP 320.0
               0.0           13.
               0.3           13.

*FMSURF 1.875E-4
*FMCAP 1.0E-4
*FMOIL 0.5
*FMMOB 50
*EPSURF 1.0
*EPCAP 1.0
*EPOIL 1.0

**  Set #1:  No foam, corresponding to no SURFACT
**  ---------------------------------------------

*KRINTRP 1

*DTRAPW  1.0  ** no mobility reduction

*SWT   **  Water-oil relative permeabilities
**   Sw        Krw      Krow
**  -----     -------    -------
 0.0930000       0.0   1.00000       0.0
 0.1500000 1.7000E-4 0.8400000       0.0
 0.2000000 8.0000E-4 0.7100000       0.0
 0.2500000 0.0024000 0.5800000       0.0
 0.3000000 0.0061000 0.4650000       0.0
 0.4000000 0.0250000 0.2780000       0.0
 0.5000000 0.0760000 0.1360000       0.0
 0.6000000 0.1800000 0.0410000       0.0
 0.6500000 0.2600000 0.0130000       0.0
 0.7000000 0.3600000 0.0110000       0.0
 0.8000000 0.5700000 0.0060000       0.0
 0.9000000 0.7500000       0.0       0.0
   1.00000   1.00000       0.0       0.0

*SLT  *NOSWC   **  Liquid-gas relative permeabilities

**   Sl        Krg      Krog
**  ----      -------    ------
 0.1500000   1.00000       0.0       0.0
 0.4000000 0.9900000 1.0000E-4       0.0
 0.4200000 0.9850000 8.0000E-4       0.0
 0.4500000 0.9800000 0.0070000       0.0
```

```
 0.5000000 0.8500000 0.0260000       0.0
 0.5500000 0.6900000 0.0550000       0.0
 0.6000000 0.5400000 0.0900000       0.0
 0.7000000 0.2870000 0.1860000       0.0
 0.8000000 0.1140000 0.3310000       0.0
 0.9000000 0.0220000 0.5700000       0.0
 0.9500000 0.0045000 0.7600000       0.0
   1.00000       0.0   1.00000       0.0

**  Override critical saturations on table
*SWR 0.15
*SORW 0.00
*SGR 0.05
*SORG 0.16


**  Set #2:  Weak foam, corresponding to intermediate SURFACT concentration
**  ------------------------------------------------------------------------

*KRINTRP 2 *COPY 1 1    ** copy from first set, then overwrite
*DTRAPW 0.4  ** weak foam inverse mobility reduction factor (MRF=2.5)
**  Override critical saturations on table
*SWR 0.15
*SORW 0.00
*SGR 0.05
*SORG 0.16
*KRGCW 0.4

**  Set #3:  Strong foam, corresponding to high SURFACT concentration
**  ------------------------------------------------------------------

*KRINTRP 3 *COPY 1 1    ** copy from first set, then overwrite
*DTRAPW 0.02  ** strong foam inverse mobility reduction factor (MRF=50)
**  Override critical saturations on table
*SWR 0.15
*SORW 0.00
*SGR 0.05
*SORG 0.16
*KRGCW 0.02

*RPT 2    ** Second rock type for high permeability zones
**  ----------------------------------------------------------------
**  Interpolation between 3 sets: zero, weak and strong foam curves
**  Capillary number calculation is based on aqueous SURFACT IFT
**  specified at 2 temperatures and 2 SURFACT concentrations.

*INTCOMP 'SURFACT' *WATER
*INTLIN
*IFTTABLE    ** aq mole frac      IFT
    *TEMP  10.0
               0.0           13.
```

```
            0.3          13.
   *TEMP 320.0
            0.0          13.
            0.3          13.

*FMSURF 1.875E-4
*FMCAP 1.0E-4
*FMOIL 0.5
*FMMOB 50
*EPSURF 1.0
*EPCAP 1.0
*EPOIL 1.0
**  Set #1:  No foam, corresponding to no SURFACT
**  ---------------------------------------------

*KRINTRP 4

*DTRAPW  1.0  ** no mobility reduction

*SWT   **  Water-oil relative permeabilities

**   Sw        Krw      Krow
**  -----     -------   -------
      0.0       0.0   1.00000       0.0
 0.2000000 0.2000000 0.8000000       0.0
 0.4000000 0.4000000 0.6000000       0.0
 0.6000000 0.6000000 0.4000000       0.0
 0.8000000 0.8000000 0.2000000       0.0
   1.00000   1.00000       0.0       0.0

*SLT  *NOSWC   **  Liquid-gas relative permeabilities

**   Sl        Krg      Krog
**  ----      -------   ------
      0.0   1.00000       0.0       0.0
 0.2000000 0.8000000 0.2000000       0.0
 0.4000000 0.6000000 0.4000000       0.0
 0.6000000 0.4000000 0.6000000       0.0
 0.8000000 0.2000000 0.8000000       0.0
   1.00000       0.0   1.00000       0.0

**  Override critical saturations on table
*SWR 0.15
*SORW 0.01
*SGR 0.05
*SORG 0.16

**  Set #2:  Weak foam, corresponding to intermediate SURFACT concentration
**  ----------------------------------------------------------------------
*KRINTRP 5 *COPY 2 1    ** copy from first set, then overwrite
*DTRAPW 0.4  ** weak foam inverse mobility reduction factor (MRF=2.5)
```

```
**  Override critical saturations on table
*SWR 0.15
*SORW 0.01
*SGR 0.05
*SORG 0.16
*KRGCW 0.4

**  Set #3:  Strong foam, corresponding to high SURFACT concentration
**  ----------------------------------------------------------------
*KRINTRP 6 *COPY 2 1    ** copy from first set, then overwrite
*DTRAPW 0.02  ** strong foam inverse mobility reduction factor (MRF=50)
**  Override critical saturations on table
*SWR 0.15
*SORW 0.01
*SGR 0.05
*SORG 0.16
*KRGCW 0.02


**  Adsorption Data
**  ---------------
*ADSCOMP 'SURFACT' *WATER   **Data for reversible aqueous surfactant adsorption
*ADMAXT 2.56   ** no mobility effects
*ADSLANG *TEMP
    51.0 5.41e+6 0 2.1e+6   ** Langmuir concentration coefficients at T=51
   151.0 1.08e+6 0 9.3e+5   ** Langmuir concentration coefficients at T=151
   250.0 2.00e+5 0 5.3e+5   ** Langmuir concentration coefficients at T=250

*INITIAL
**  =============  INITIAL CONDITIONS  =====================

*PRES *KVAR              800.0 688.0 532.0
*SW   *CON 0.15          **Standard bed permeability
     *MOD 1  1 1:2 =  .5   ** Higher perm commumication path
         6  1 1:2 =  .5   ** Higher perm commumication path
       1:9  1   3 =  .5   ** Higher perm commumication path

*TEMP *CON 15.5           **Standard bed permeability
     *MOD 1  1 1:2 =  110  ** Higher perm commumication path
         6  1 1:2 =  110  ** Higher perm commumication path
       1:9  1   3 =  110  ** Higher perm commumication path

*mfrac_wat 'WATER' *con 1

*NUMERICAL



**  =============  NUMERICAL CONTROL  =====================
** All these can be defaulted.  The definitions
** here match the previous data.
```

```
*TFORM *SXY

*DTMAX 100.0
*SDEGREE 1
*SORDER *RCMRB
*UPSTREAM *KLEVEL

*NORM      *PRESS 500  *SATUR .2   *TEMP 45  Y .2  *W .2

*RUN

**  ==============  RECURRENT DATA  ======================

*TIME 0
  *DTWELL 0.1

  *WELL 1 'INJTR'  *FRAC .1667    ** Well list
  *WELL 2 'PRODN'  *FRAC .5000

  *PRODUCER 'PRODN'
  *OPERATE *STL 30.0
  *PERF 'PRODN'   **  i j k  wi
            6 1 1 2345.49 ** 200

  *INJECTOR *MOBWEIGHT 'INJTR'
  *INCOMP  *WATER  1.0  0.0  0.0
  *TINJW 210
  *QUAL .7
  *OPERATE *STW 150

  *PERF 'INJTR'   ** i j k  wi
          1 1 1 469.098 ** 40

** Obtain printouts and results at the following times
  *TIME  365
  *TIME  730
  *DTWELL  1.0

  *INJECTOR MOBWEIGHT 'INJTR'

  *INCOMP *WATER .9998125   1.875E-4  0         ** inj surfactant (1.0wt%)
  *TINJW 210
  *QUAL .7
  *OPERATE *STW 150

  *PERF 'INJTR'   ** i j k  wi
           1 1 1 469.098 ** 40
*TIME 1095
*TIME 1460.0
*STOP
```

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