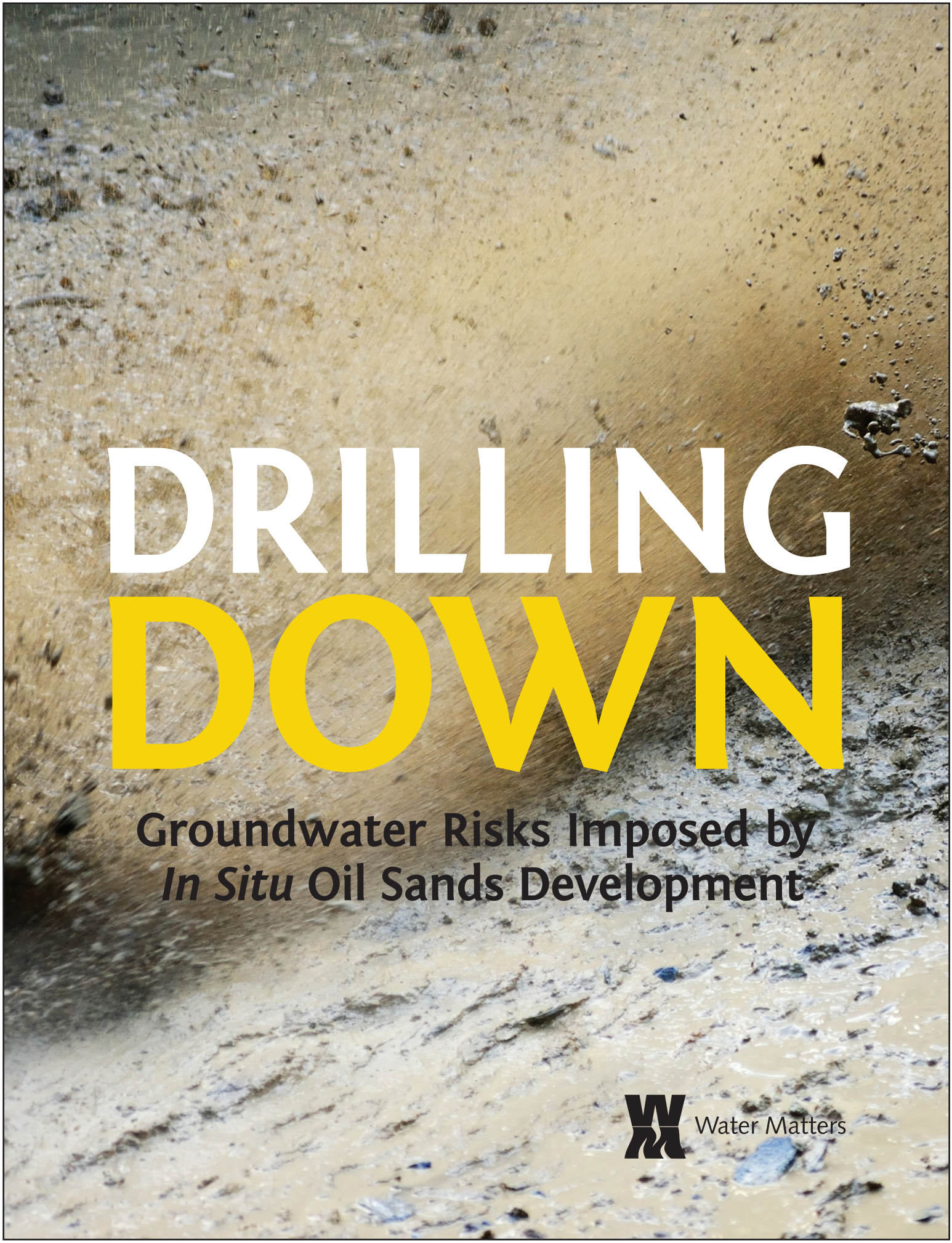

DRILLING DOWN

Groundwater Risks Imposed by *In Situ* Oil Sands Development

Water Matters

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Groundwater Risks Imposed by *In Situ* Oil Sands Development

July 2011

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EXECUTIVE SUMMARY

Groundwater is a fundamental part of the hydrological cycle. It is always moving beneath us and often contributes to or is recharged by surface waters. However, unlike surface water bodies (*i.e.*, rivers, lakes, and wetlands), water in underground aquifers moves very slowly. Consequently, groundwater aquifers take much longer to recover from substantial changes in either water quantity or quality that are caused by industrial activity. Therefore, it is critical to develop an integrated understanding of regional groundwater quantity, flow, and quality prior to approving groundwater-intensive developments, so that groundwater and surface waters are sustainably managed and any substantial risks to them are minimized.

Unfortunately, the rapid rate of approvals and construction of *in situ* oil sands operations in Alberta seem to have outpaced the Government of Alberta's development of legislative and regulatory controls to protect groundwater resources that are critical to sustaining healthy rivers, lakes, and wetlands. The risks to groundwater resources associated with *in situ* oil sands operations are complex, and they arise at every stage of *in situ* oil sands development and operation. The continued failure to assess or consider risks to groundwater associated with *in situ* oil sands developments will have far reaching consequences. For instance, the contamination of groundwater is difficult and costly to remedy – estimated costs are generally 30 to 40 times (and up to 200 times) greater than the prevention of contamination. Therefore, it is prudent that Alberta develop a clear understanding of groundwater quality, quantity and dynamics, the cumulative effects of regional development on groundwater and surface water resources, and the sustainable limits for groundwater extraction if our goal is to sustainably manage our waters and avoid substantial costs of attempting to deal with problems after they arise.

Several aspects of *in situ* oil sands development and its growing dependence on groundwater in north-central Alberta pose substantial risks to regional groundwater resources:

- surface land disturbances and unsealed wells that increase the potential for groundwater contamination;
- unquantified groundwater supplies that complicate the ability of *in situ* oil sands projects to meet their approval obligations to rely on groundwater for steam production;
- buried groundwater channels that permit vertical and horizontal movement of contaminants from *in situ* oil sands operations;
- and shallow aquifers that are particularly susceptible to harm and play an important role in recharging regional lakes, rivers, and streams.

In addition, the Lower Athabasca Region Groundwater Management Framework lacks rigour and substance, and provides little opportunity for the sustainable management of groundwater in the oil sands region. Simply put, it is not adequate to protect groundwater resources from the risks posed by *in situ* oil sands operations.

In this report we provide an introduction to *in situ* bitumen extraction and groundwater resources and issues in Alberta's oil sands region, a preliminary assessment of the substance of the groundwater framework and associated legislation, and ten recommendations that, if followed, would better protect Alberta's groundwater for future generations.

RECOMMENDATIONS

The Government of Alberta should:

1. Create an independent scientific panel to a) design a scientific plan that will enable the determination of pre-development baselines for surface and groundwater quality and quantity and sustainable yields from local and regional aquifers, and b) design a groundwater assessment and monitoring plan that will permit the detection of significant changes in groundwater quality and flow dynamics and patterns, and the distinction between natural and human causes for any identified changes in groundwater quantity or quality.

2. Commit to adopting, funding, and fully implementing a scientific groundwater assessment and monitoring program described in Recommendation #1, thereby ensuring that a sufficiently detailed understanding of the hydrogeology and groundwater dynamics is acquired to properly manage and limit oil sands development and protect groundwater and surface water resources.

3. Significantly increase in-house and external research capacity and funding to quantify and qualify groundwater resources in Alberta.

4. Expand groundwater assessment and monitoring to include not only all non-saline aquifers but also all saline aquifers with concentrations between 4,000 and 10,000 mg/L. This will contribute to a better understanding of the effects of industry use of saline groundwater and injection of saline waste materials into deep aquifers and formations.

5. Within a single government ministry, collect, organize, and integrate all industry data collected to date for saline and non-saline water use, perform (as much as possible) an up-to-date cumulative regional assessment of oil sands extractors' groundwater use and impacts, and make both the data and cumulative assessment freely accessible, searchable, and available to the public.

6. Develop and implement, as soon as possible, science-based industry performance indicators related to groundwater quality, quantity, and sustainable yield, and regulatory triggers for government responses to either anticipated or identified impacts on either groundwater quality or dynamics.

7. Immediately design and adopt interim indicators and limits that are based on the precautionary principle and the best available current understanding of local and regional sustainable groundwater, to prevent harm to groundwater resources while more appropriate indicators and triggers are being developed as per Recommendation #6.

8. Adopt, regulatory and management responses as part of the Lower Athabasca Regional Plan and other relevant laws, policies, guidelines and ERCB directives, that include the requirement to stop groundwater extraction or steam or waste injection when identified groundwater indicator thresholds or triggers are reached or surpassed.

9. Include in all approvals for oilfield or waste injection and appropriate governing regulations the operational requirement to immediately report to the primary governing or regulatory body any evidence of unexpected significant geological anomalies or primary fractures caused by injection of steam, water, chemicals, or waste products, and adopt regulatory and industry response triggers that impose immediate cessation of local injection operations in such an event, when the potential effects may compromise the integrity and utility of either aquifers or bitumen-bearing formations.

10. Develop a publicly accessible and searchable database of all wells used for *in situ* oil sands operations, detailing which wells have been reclaimed and which have not, and coordinate and impose a shared financial responsibility for all operators for sealing and maintaining orphaned wells.

1 INTRODUCTION

Groundwater is a fundamental part of the hydrological cycle. It is always moving beneath us and often contributes to or is recharged by surface waters. However, unlike surface water bodies (*i.e.*, rivers, lakes, and wetlands), water in underground aquifers moves very slowly. Consequently, groundwater aquifers take much longer to recover from substantial changes in either water quantity or quality that are caused by industrial activity. Therefore, it is critical to develop an integrated understanding of regional groundwater quantity, flow, and quality prior to approving groundwater-intensive developments, so that groundwater and surface waters are sustainably managed and any substantial risks to them are minimized.

Unfortunately, the rapid rate of approvals and construction of *in situ* oil sands operations in Alberta seem to have outpaced the Government of Alberta's development of legislative and regulatory controls to protect groundwater resources that are critical to sustaining healthy rivers, lakes, and wetlands. The risks to groundwater resources associated with *in situ* oil sands operations are complex, and they arise at every stage of *in situ* oil sands development and execution. The continued failure to assess or consider risks to groundwater associated with *in situ* oil sands developments will have far reaching consequences. The contamination of groundwater is difficult and costly to remedy, with estimated costs often 30 to 40 times (and up to 200 times) greater than the costs associated with simply preventing contamination from happening.[1] Therefore, it is prudent that Alberta develop a clear understanding of groundwater quality, quantity and dynamics, the cumulative effects of regional development on groundwater and surface water resources, and the sustainable limits for groundwater extraction if our goal is to sustainably manage our waters and avoid substantial costs of attempting to deal with problems after they arise.

The issues and problems that we describe here are not restricted to the oil sands industry or the oil sands region, and our discussion and recommendations apply equally to other intensive groundwater-dependent development that may be occurring elsewhere.

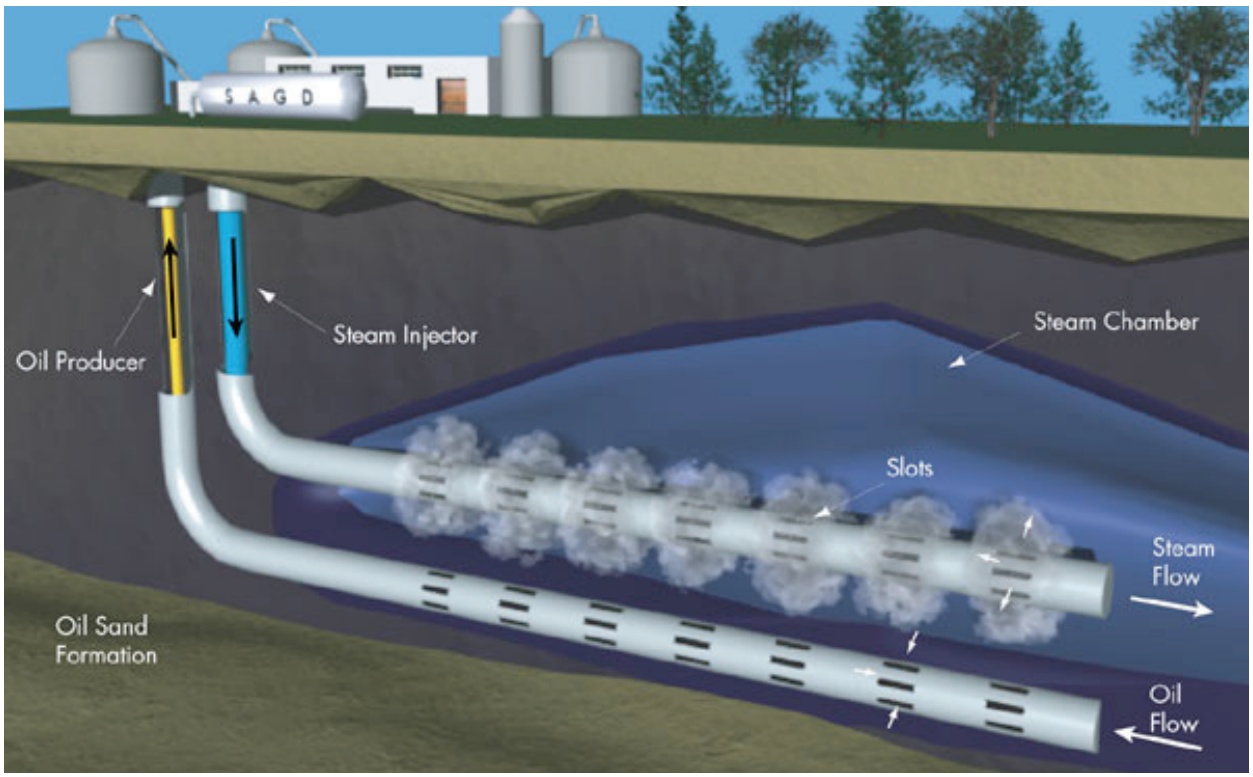
1.1 WHAT IS *IN SITU* OIL SANDS DEVELOPMENT?

Eighty-two percent of Alberta's oil sands are too deep to mine and must be recovered by *in situ* methods (Latin for "in place").[2] *In situ* oil sands extraction methods involve drilling wells through layers of gravel, sand, glacial till, silt (collectively referred to as overburden) and the underlying rock to inject steam into deep oil sands deposits to recover bitumen. This process is known as thermal recovery, because the heat from the steam warms oil sands, which increases the fluidity of the bitumen and enables easier separation of it from sand and water particles.

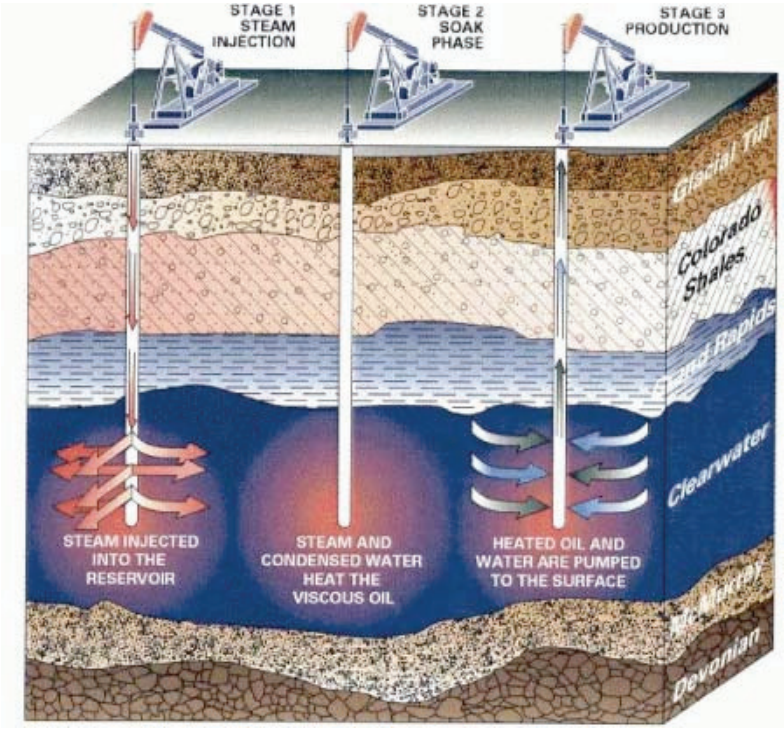
Two types of *in situ* oil sands extraction exist: Steam Assisted Gravity Drainage (SAGD) and Cyclical Steam Simulation (CSS). SAGD is generally used for oil where open pit mining for oil sands is uneconomical. SAGD is preferred for oil sands deposits from 150 to 300 metres deep that may be thin and fragmented. SAGD uses water that is low in salinity to produce high quality steam that is generally 250 °C. To recover bitumen from thick deposits deeper than 300 m, CSS — also known as "huff and puff" — is used, which requires steam of 300 to 340 °C.[3]

SAGD requires less water than CSS and has a production rate that is 15 times higher. At a 90% recovery rate, it takes 1.7 tonnes of oil sands to produce one barrel (159 litres) of synthetic crude oil.[4] However, SAGD extraction typically has an estimated recovery rate of up to 60%, which is equivalent to 2.6 tonnes of oil sands to produce a barrel of synthetic crude oil.[5]

STEAM ASSISTED GRAVITY DRAINAGE (SAGD)
SOURCE: The Pembina Institute 2005, see www.oilsandswatch.org



CYCLICAL STEAM SIMULATION (CSS)
SOURCE: Imperial Oil 2001, original citation http://www.ceaa.gc.ca/default.asp?lang=En&n=AFF9B551-1&toc=show&offset=8



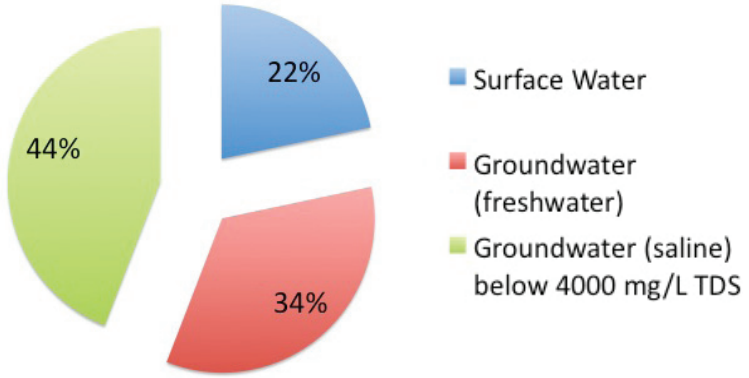
CSS has been used in the Cold Lake and Peace River regions for more than 20 years, and SAGD operations are generally located in the Athabasca River Basin and near Cold Lake in the Beaver River Basin. In addition to high volumes of oil sands, production of synthetic crude oil via *in situ* oil sands extraction also requires high volumes of water, which may come from either nearby rivers, lakes or streams, or from groundwater deposits. The high volumes of water needed would pose a risk to surface waters (*i.e.*, lakes and rivers) if all water came from them. This and the desire to avoid having to transport water substantial distances from surface water sources have resulted in prioritizing the use of groundwater for *in situ* oil sands extraction. Because of this, the rapid expansion of oil sands mining and *in situ* extraction projects has increased the combined risk to groundwater in the oil sands region in the Peace, Athabasca, and Beaver River basins.

REGIONS IN ALBERTA WITH OIL SANDS DEPOSITS
SOURCE: ERCB with permission, 2010.

1.2 WHY SAGD?

By 2020, oil from *in situ* bitumen extraction is expected to make up 40 percent of Canada's oil[6], of which SAGD is likely to provide the bulk of the supply growth by 2015.[7] Most of the proposed *in situ* oil sands developments are expected to be in the Athabasca River Basin and use SAGD[8], largely because the Athabasca River Basin contains the most deposits.[9] This large expansion of *in situ* bitumen extraction is expected to increase groundwater use in the Athabasca River Basin by four to seven times (378 percent in a low development scenario and up to 668 percent in a high development scenario).[10]

TOTAL WATER USE BY *IN SITU* OIL SANDS PROJECTS 2009
SOURCE: Alberta Environment, personal communications, 2011.



1.3 HOW DOES IT WORK?

Bitumen extracted from oil sands does not flow easily. At ground temperature, bitumen in oil sands is very viscous and practically immobile. Much like molasses, bitumen flows more easily as it warms, which is why steam is used as a source of heat (Figure 1).

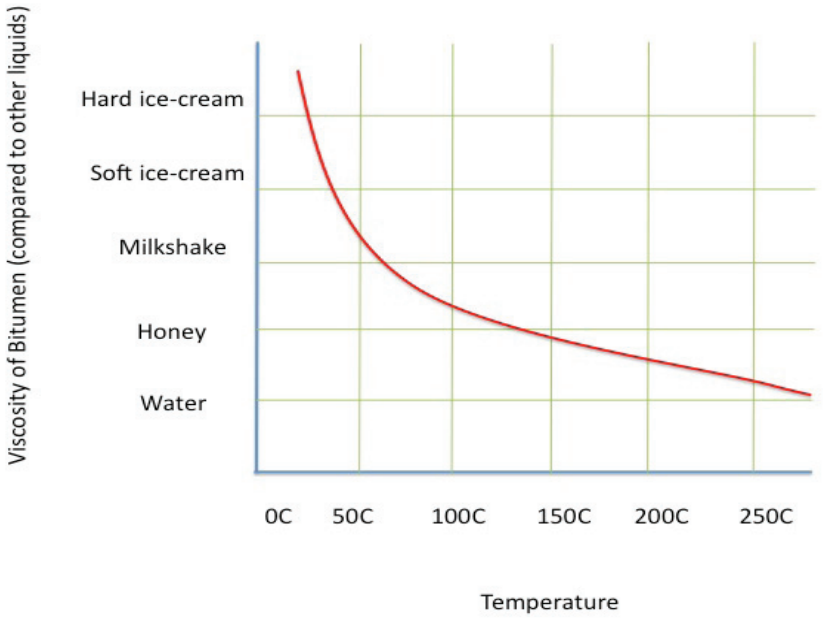
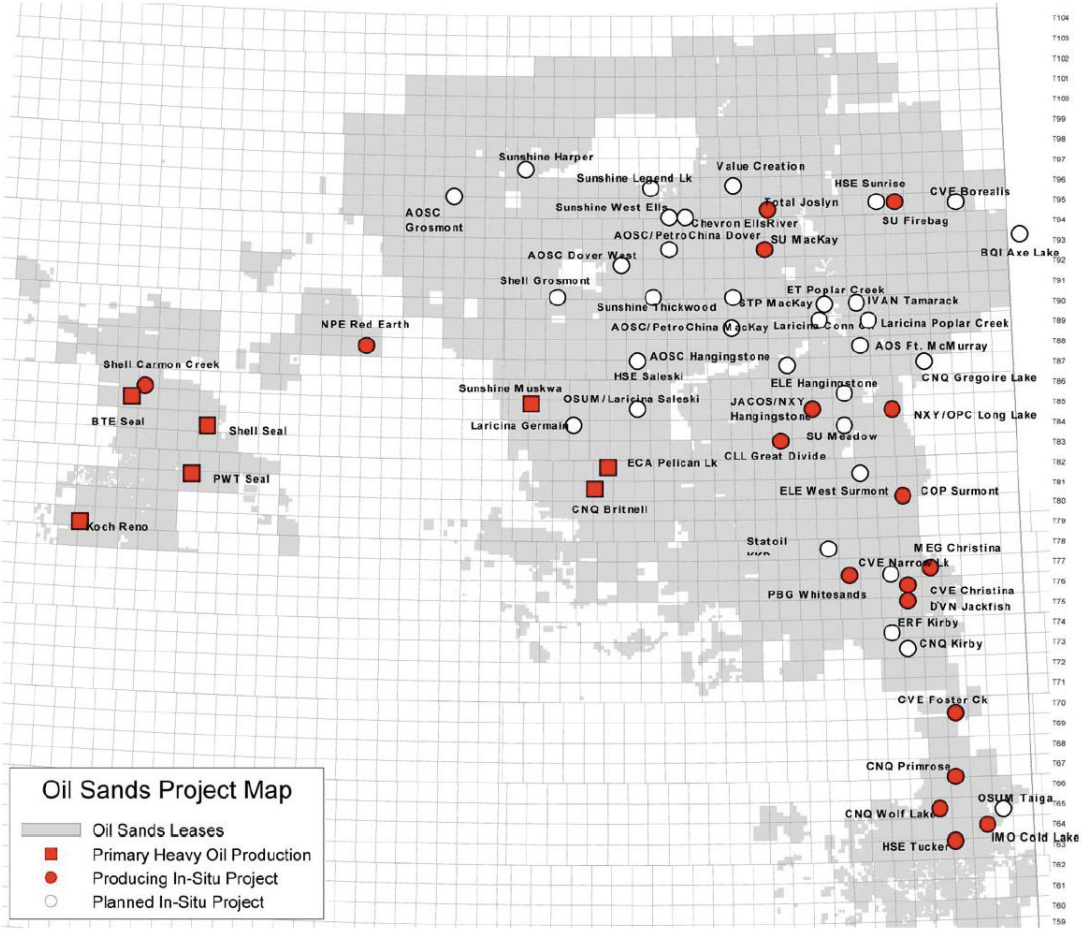


FIGURE 1. Conceptual changes in viscosity or fluidity of bitumen as it is heated[11]

In SAGD, wells are drilled in pairs, one injecting steam and the other extracting the liquefied bitumen. The pairs of wells, typically 0.2 m in diameter, are drilled to depths between 150 and 300 m, where oil sands deposits are thin, then run out horizontally for up to 1000 m.[12] The upper well typically sits five metres above the lower well and uses high quality steam to heat the surrounding oil sands deposit for three to six months, creating a steam chamber to make the bitumen fluid. A steam chamber is formed by the steam injection, producing a liquid bitumen-water mixture that flows to and is pumped from the bottom well.[13] The water that is mixed with the bitumen originates from condensation of the injected steam and from water present with the bitumen in the formation.

LOCATION OF EXISTING AND PLANNED *IN SITU* OIL SANDS PROJECTS IN ALBERTA'S OIL SANDS REGIONS
SOURCE: Macquarie Securities, 2010, permission granted.



The total life of a SAGD project, from exploration to reclamation, is estimated to be 46 to 55 years.[14] The first five years of an *in situ* oil sands project is typically the exploration and construction phase, involving seismic testing and assessment of deposits with exploration wells, and preparation and drilling of pads of horizontal wells.[15] The operational lifetime of a SAGD project ranges from 20 to 35 years.[16] Because horizontal wells have a producing life of 8 to 12 years and take 5 to 15 years to decommission,[17] many pairs of wells are installed and used to tap into the target zone during the operational phase.

1.4 USE, RECYCLING AND DISPOSAL OF WATER IN SAGD OPERATIONS

In situ bitumen extraction uses both surface water (water from lakes and rivers) and groundwater. Groundwater is typically fresh in shallow aquifers and gets more saline with depth.[18] The Government of Alberta plans to implement directives[19] to decrease the amount of freshwater used by *in situ* oil sands operations. However, it is unclear what effect this policy will have because the source of water for SAGD depends largely on the proximity of available sources and the geology of the region.[20]

High-quality steam is needed in the first three to six months of a SAGD operation, requiring freshwater (or its equivalent) with few dissolved salts in it. Consequently, where saline groundwater is used, the salts must be removed.[21] In many cases, claims are made that up to 95% of water used for SAGD is recycled. However, these calculated recycle rates are based on how much non-saline water is used (*i.e.*, fresh water that is of similar quality to that found in lakes and rivers), and do not consider the amount of saline water used in the total mix of fresh and saline water.[22] As we describe in more detail below, saline groundwater is largely unmonitored and its use unaccounted for in the oil sands region. Therefore, *in situ* oil sands operations could augment their operations with substantial amounts of saline water that is neither recycled nor accounted for and still report a 95% recycle rate for water use (see Figure 2). For this reason, total water use and recycling by *in situ* oil sands operations remain hard to quantify, and the potential for over-exploitation of saline groundwater is significant. Rather than using the calculated recycle rate, we advise that the make-up rate be used instead to characterize water use by *in situ* projects, because it reflects the total amount of water (saline and non-saline) consumed by steam production and losses in the bitumen-bearing formations, and other on-site uses or disposal.[22]

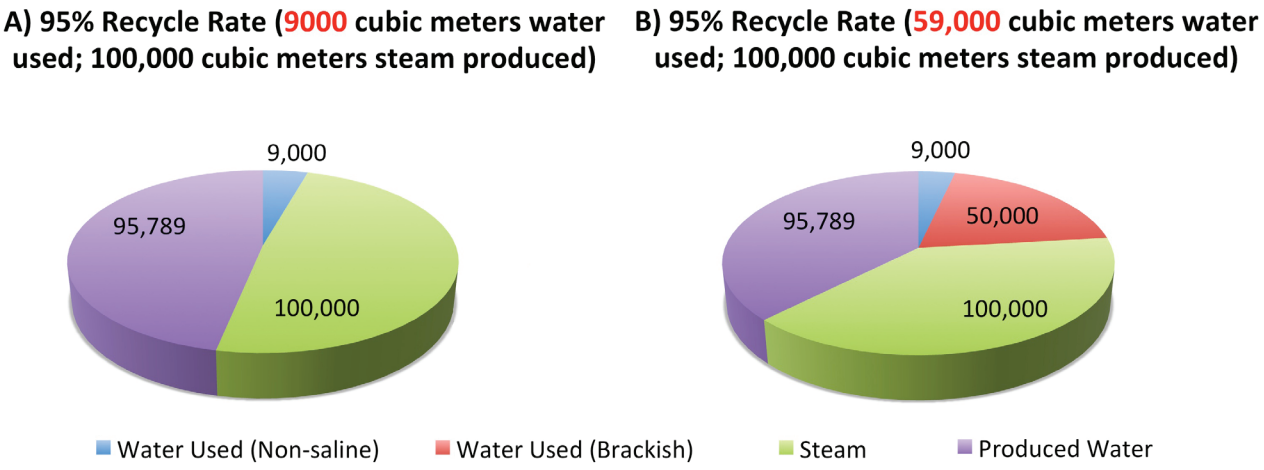


FIGURE 2. The ERCB method for calculating water recycling rates for SAGD *in situ* oil sands projects only considers the amount of fresh water used for steam production, and not the use of brackish groundwater in steam production or other processes or operations that depend upon it. This can result in a deceptively high water recycling rate that does not represent total water use and remains the same despite high brackish water use.

Each company has different processes and practices for the recycling of water, but generally produced water - water recovered with bitumen from the bitumen-bearing formations - must be treated (e.g., use of additives such as water softeners) prior to being recycled in a SAGD operation. Any fraction of water that cannot be reused is disposed of as waste in deep wells or in a Class II landfill.[23]

2 POLICIES GOVERNING OR AFFECTING *IN SITU* GROUNDWATER USE

There are number of provincial acts, policies, regulations and guidelines that pertain to industrial use of groundwater in Alberta, including:

- the *Water Act*, which governs licencing of access to and use of groundwater;
- the Alberta *Environmental Protection and Enhancement Act*, which governs negative impacts on groundwater quality;
- the *Alberta Tier 1 and Tier 2 Soil and Groundwater Remediation Guidelines*; and
- the *Groundwater Evaluation Guideline*.

For any of these to work effectively, an understanding of groundwater dynamics and quality and groundwater – surface water interactions is necessary, if our goal is to manage and protect the integrity of groundwater resources and lakes, rivers, and wetlands in Alberta. In this report we will focus on two policy documents in particular: the draft *Lower Athabasca Region Groundwater Management Framework*, and the *Water Conservation and Allocation Policy for Oilfield Injection*.

2.1 LOWER ATHABASCA REGION GROUNDWATER MANAGEMENT FRAMEWORK

The Government of Alberta recently released its Lower Athabasca Regional Plan (LARP), which included the draft *Lower Athabasca Region Groundwater Management Framework* (Groundwater Framework).[24] The Groundwater Framework is intended to permit sustainable management of non-saline groundwater resources in the Lower Athabasca Region, including managing the cumulative effects of regional development on them. Its stated goals include:

- establishing baseline groundwater conditions so changes can be detected and understood;
- provide a consistent approach to understanding potential effects of regional development activities on regional groundwaters; and
- facilitate assessment of future changes in regional groundwater due to expanding industrial development and climate change.[25]

This policy applies to groundwater with concentrations of total dissolved solids (or salinity) that are less than 4,000 mg/L and classified as "freshwater" or "non-saline". Consequently (and unfortunately), industrial use of groundwater with salinity greater than 4,000 mg/L is neither considered nor affected by the Groundwater Framework.

The key principles in the Groundwater Framework include the prevention of groundwater pollution, identification and management of risk and adverse trends in groundwater quantity and condition, and adoption of a regional rather than local approach to management of regional development and groundwater.[26] All of these are contingent on understanding of the nature and dynamics of regional

groundwater resources and cumulative effects of local developments on a regional scale. Therefore, detailed quantification and monitoring of both groundwater quality and dynamics and the industrial impacts on them are essential to achieving the goals of the Groundwater Framework. For this reason, one of the apparent commitments of the Groundwater Framework is the development of a comprehensive regional groundwater monitoring network.[27]

Despite some on-going groundwater monitoring in the oil sands region since the 1970s, groundwater quality in the region is highly variable and understanding of local conditions is anywhere from poor to fair. The lack of sufficient temporal and spatial monitoring is the primary reason for this lack of understanding, and it is expected that further monitoring, assessment, and regional integration will contribute to clarifying the state of regional groundwater and its sensitivity to industrial development.[28]

While the goals and objectives of the Groundwater Framework are admirable, the groundwater monitoring and assessment programs described in it are insufficient to achieve them. Currently, there are no regional limits on groundwater use in the oil sands region, and there are no identified criteria that trigger a regulatory review or imposition of limits on industrial use of groundwater.[29] Despite an acknowledged requirement for a detailed understanding of regional dynamics and quality of groundwater, monitoring programs will only consider changes in water levels and water chemistry in groundwater monitoring wells.[30] Among other problems, this will prevent anyone from being able to predict where a groundwater contaminant plume will flow to or how quickly it will move. Without the collection of information to determine rates and direction of groundwater flow, the general lack of understanding of groundwater in the region and the impacts on it associated with oil sands development will continue.

2.2 WATER CONSERVATION AND ALLOCATION POLICY FOR OILFIELD INJECTION

The *Water Conservation and Allocation Policy for Oilfield Injection* is the primary policy determining and affecting the use of freshwater and groundwater by *in situ* operators.[31] The stated objective of the policy is to "enhance the conservation and protection of Alberta's water; and to reduce or eliminate, on a case-by-case basis, the use of non-saline water resources for oilfield injection purposes".[32] However, before this objective is even stated in the policy, it is qualified by reference to the importance of respecting the rights of current resource rights holders.[33] Furthermore, it is made clear in the policy that use of fresh water for oilfield injection is permissible where use of saline water is not "feasible" and use of fresh water will prevent "stranding" oil resources.[34]

According to the policy, SAGD operators must investigate the availability of alternative water supplies prior to applying to develop a source of freshwater, and submit information from the investigation to the ERCB with the application.[35] As a result, the assessment of feasibility is not necessarily related to technical feasibility itself, but framed in terms of an economic evaluation of alternatives. The assessment excludes substantial environmental costs of freshwater use by SAGD operations, such as the source of freshwater or the implications to groundwater aquifers and groundwater–surface water interactions. Therefore, the policy fails to take into account the real worth and value of Alberta's aquifers, rivers, lakes, and wetlands. This tendency to put aside environmental concerns in order to facilitate recovery of oil resources is a function of the long-standing legal and regulatory foundation in Alberta, which is primarily concerned with maximizing oil recovery.[36]

The *Water Conservation and Allocation Guideline for Oilfield Injection* is intended to provide more clarity for implementation of the policy by purportedly imposing a limit on project-specific use of groundwater:

> An applicant that proposes to use non-saline groundwater for underground (oilfield) injection will be restricted to a maximum of one-half of the long-term yield of a given aquifer in the immediate vicinity of the water source well. This will be accomplished by limiting drawdown in the production aquifer, as measured in an observation well at a distance of 150 metres from the production well, to 35 per cent during the first year of operation and no more than 50 per cent over the life of the project.[37]

However, there is no scientific basis to this purported limit, because there has been no scientific assessment or determination of sustainable groundwater yields in the oil sands region. No scientific assessment has been done either locally or regionally, and no assessment has been made between the interactions of groundwater and surface water. For example, project-specific limits for groundwater use should be based on an integrated assessment of groundwater data and an understanding of groundwater dynamics, aquifer flow rates or yields, volumes of industrial groundwater use, and volumes of wastewater injection or the amounts of chemical wastes and toxins in wastewater injected for deep storage.

2.3 DETERMINING SUSTAINABLE GROUNDWATER USE DEMANDS DETAILED KNOWLEDGE

Alberta Environment recognizes that unsustainable groundwater pumping rates will result in depletion of aquifers and cause groundwater levels and supply to decline.[38] However, while conservation and long-term sustainability of groundwater systems are primary management objectives for Alberta Environment, there is no defined meaning of "sustainable groundwater yield" in Alberta's legislation or regulations that govern groundwater management, use, and protection.[39] This disconnect between primary management objectives and governing laws is problematic, because it permits leeway in the interpretation of what should otherwise be a very clear concept related to long-term sustainability of groundwater use and management.

A reasonable interpretation of sustainable pumping rates would be those that do not result in depletion of aquifers or cause groundwater levels or supplies to decline. Often, a sustainable or safe yield is interpreted as that which ensures the long-term balance between the amount of groundwater withdrawn annually and the annual amount recharged to the aquifer via precipitation and surface water seepage. However, groundwater aquifers support stream, spring, wetland, and other groundwater-dependent ecosystems, in addition to human uses such as *in situ* oil sands developments. For this reason, the sustainable pumping rate (or yield) must be significantly less than an aquifer's recharge rates, in order for the aquifer to continue to provide the amount and quality of freshwater necessary to sustain the surface ecosystems that rely upon it.[40]

Sustainable management of groundwater demands a detailed understanding of groundwater-surface water interactions and flow or supply rates in aquifers themselves. Because water quality in an aquifer is as important as water quantity, a detailed understanding of the concentrations of chemicals of concern also is necessary to properly manage groundwater, as well as transport rates through and between aquifers, and between aquifers and surface waters. Adequately characterizing the complex dynamics of aquifers and their interactions with surface water must be a priority and a prerequisite to allowing more groundwater use for bitumen extraction. Simply monitoring concentrations of chemicals and water levels in wells will tell us little about whether groundwater supplies or our use of them are sustainable.

3 ACCIDENTS HAPPEN: RISKS POSED BY *IN SITU* OIL SANDS EXTRACTION

In situ oil sands extraction is promoted by both industry and government as more environmentally friendly or safe than mining. However, this does not accurately reflect the risks inherent to current *in situ* oil sands extraction technologies and practices. We present as case studies two recent serious incidents at oil sands projects under development that highlight the risks to groundwater associated with oil sands projects and another case study that illustrates the lack of detailed understanding of groundwater dynamics or aquifers. The first involves an explosive release of steam from Total E & P Canada's ("Total's") Joslyn Creek SAGD project on May 18, 2006, and the second is an unanticipated penetration of a pressurized aquifer by Shell Canada during digging in a mine pit at its Muskeg River operation in late 2010. Lastly, we describe a recent application by Nexen Inc. for a change of source water from saline groundwater to surface freshwater as an example of the uncertainty of industrial plans and promises to rely upon saline groundwater supplies for *in situ* developments in the Lower Athabasca region.

3.1 CASE STUDY 1: TOTAL'S JOSLYN CREEK CAP-ROCK EXPLOSION

On May 18, 2006, a violent steam release at Total's Joslyn Creek SAGD project came up through the cap-rock[41] overlaying the bitumen layer being extracted, resulting in a crater 125 meters by 75 meters and throwing rock 300 m sideways. According to the ERCB's investigation report detailing the Joslyn Creek steam eruption, Total had breached a number of its approval conditions, including:

- injecting steam at much higher pressures than proposed or approved;
- operating at base-hole pressures significantly higher than proposed or approved; and
- failing to implement appropriate alarms and automatic shutdown of wells exceeding reservoir fracture pressures.

Prior to receiving its approvals, Total had characterized the Clearwater shale (the approved cap-rock for the project) as consistently 20 to 30 m thick with no pre-existing fractures, and as an effective barrier to vertical flow of steam or water. Total also concluded that the Wabiskaw A shale, a few meters below the Clearwater cap-rock, was an effective barrier to the vertical flow of steam and liquids. However, after the accident the ERCB concluded that the Clearwater "cap-rock" was "non-lithified, silty mudstone, with some sandy interbeds and some vertical burrows filled with sand". Natural geological processes also may have resulted in some fracturing and faulting in both the Clearwater shale cap-rock and the bitumen reservoir.[42] In other words, despite Total's assessment, the ERCB concluded that the Clearwater cap-rock was not a thick, even, protective layer that could withstand the high pressures of steam injection and prevent vertical movement of steam, water, and other compounds. Instead, this cap-rock layer was weak, made up of a mixed layer of mudstone, sand, and vertical sand channels with faults and fractures.

The ERCB attributed the difference between Total's opinion and reality to insufficient initial testing that yielded test results that were not representative of the true case, and expressed concerns that Total's high-density 3-D seismic interpretations were inaccurate.[43] Both Total and the ERCB also concluded that there was evidence of an initial fracturing more than a month before the blow-out. Evidence also showed that the ultimate blow-out was not the result of a single fracturing event on May 18, 2006, but rather the result of a month-long accumulation of steam and hot water below the cap-rock. According to the ERCB, the most

likely initial pathways for vertical movement of steam were fractures that connected to a nearby vertical evaluation well (20 m from the injection well), then upward through gaps in the evaluation well's cement plug.[44] This is consistent with a warning about the potential in SAGD developments for "expanding steam chambers from injection wells completed close to valley walls that can escape through breaches in the cap rock which loses pressure integrity" that was included in a recent report by the Royal Society of Canada.[45]

Total eventually conceded that this blow-out was caused by unknown and unexpected anomalies in and above the cap-rock that failed when the pressure of steam pumped into the ground became too high and permitted accumulation and vertical movement of steam, water, and other chemicals.[46]

3.2 CASE STUDY 2: SHELL CANADA MUSKEG RIVER GROUNDWATER PERFORATION

In December 2010, hydrogeological connections to a pressurized deep saline aquifer were breached by Shell Canada during the digging of a mine pit at its Muskeg River operation.[47] A shovel operator was doing final pit-floor clean-up in preparation for turning the mined out oil sands pit into a tailings pond, when water suddenly started to bubble up from the floor of the pit. Initially, it was thought that the water was the normal basal (shallow) water that drains out of the land and wetlands surrounding oil sands mine pits in northern Alberta, which is simply pumped out of the pit into holding ponds. However, it soon became apparent that the water was saline and contained small amounts hydrogen sulphide, indicating that it came from some deep, saline aquifer originating far below the mine pit floor.

As of early May, 2011, the saline groundwater was still flowing into what was intended to be a tailings pond but has now become a growing containment pit at the Muskeg River oil sands mine site. Shell Canada, the ERCB, and Alberta Environment are still seeking a solution to the problem, which will be to control and prevent the surface discharge of this pressurized saline groundwater beyond the containment pit.[48]

3.3 CASE STUDY 3: APPLICATION FOR SOURCE WATER CHANGE FOR OPTI-NEXEN'S LONG LAKE SAGD PROJECT

In 2010, Nexen Inc. applied to amend the water licence that was issued for its Long Lake SAGD oil sands project in northeastern Alberta so it could switch its source of project water from saline groundwater to freshwater from the Clearwater River, which was designated a Canadian Heritage River in 1997.[49] Initially, the licence issued was for saline groundwater after Opti-Nexen had promised in public environmental hearings to not use any surface waters from lakes or rivers in the region for its operations, and to rely solely on saline groundwater instead. The use of freshwater was a clear concern expressed during the initial environmental assessment[50] and at the hearings, and the project was approved on the basis that it would not use freshwater.

According to Opti's 2009 year end results and Nexen's update in February 2010, steam comprised of five to six barrels of water was needed for every barrel of bitumen produced. However, the Long Lake Project was initially approved on the basis of a 3:1 ratio of water use to bitumen production, meaning the Long Lake project has needed almost twice as much water as originally planned. Between 2007 and 2009, Nexen tripled its annual use of groundwater at this project, from 735,000 m^3 to 2,239,000 m^3. Under their proposed plan for freshwater extraction from the Clearwater River, Nexen will divert 6,205,000 m^3 of water annually[51] [between 17,000 and 25,000 m^3 daily], with an intake pipe capacity of 77,000 m^3 of water daily (*i.e.*, 28 million m^3/year, or the equivalent of 11,000 Olympic swimming pools per year).

In its application, Nexen has cited the need to withdraw water from the Clearwater River as a means of reducing the project's environmental footprint, because of groundwater supply uncertainty and a more easily accessible surface water source in the Clearwater River.[52] However, desalination of local saline groundwater

as a source of process water, as proposed and promised in the original approval application for the Long Lake SAGD Project, is now not preferred due to technical problems, elevated costs associated with saline groundwater use, and the need for greater waste management.[53]

Nexen's promises during the project approval hearings and their post-approval admission of uncertainty of groundwater supply for the Long Lake SAGD project typify a major issue complicating the use of groundwater for SAGD in the oil sands region: only estimates exist of overall recharge rates of the aquifers from which they are withdrawing water, and sustainability of supplies is uncertain. Furthermore, unless the appropriate technology for treating and converting saline groundwater into steam during the initial stages for SAGD is developed, more water than proposed for other projects will likely be needed, and more companies may insist on a switch from saline groundwater sources to fresh surface waters for SAGD projects due to technical and water supply problems.

3.4 CLASSES OF RISKS TO GROUNDWATER POSED BY *IN SITU* OIL SANDS EXTRACTION

These three examples illustrate the potential harm to groundwater inherent to *in situ* oil sands development in Alberta, which can be categorized into six risk types (see Figure 3):

1) surface disturbances;

2) uncertain groundwater supplies;

3) leaking wells;

4) buried groundwater channels;

5) shallow aquifers; and

6) connections to surface water

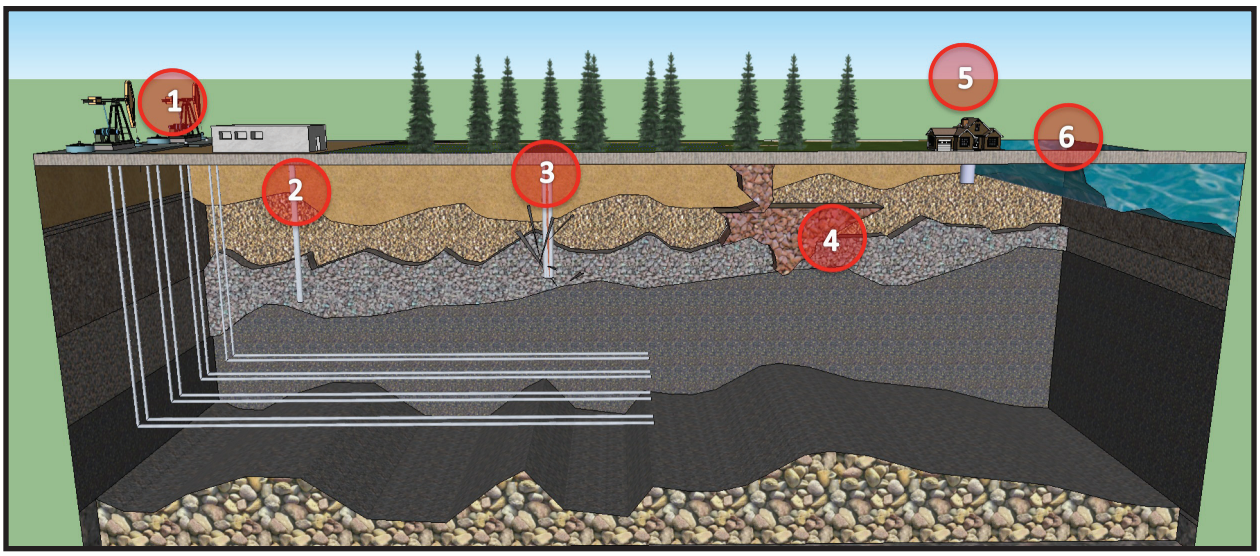
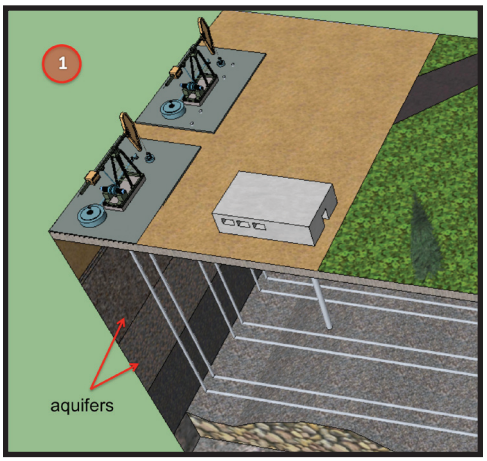


FIGURE 3. The six categories of risk associated with *in situ* oil sands development in Alberta: 1) surface disturbances; 2) uncertain groundwater supplies; 3) leaking wells; 4) buried groundwater channels; 5) shallow aquifers; and 6) connections to surface waters.

3.4.1 SURFACE DISTURBANCES



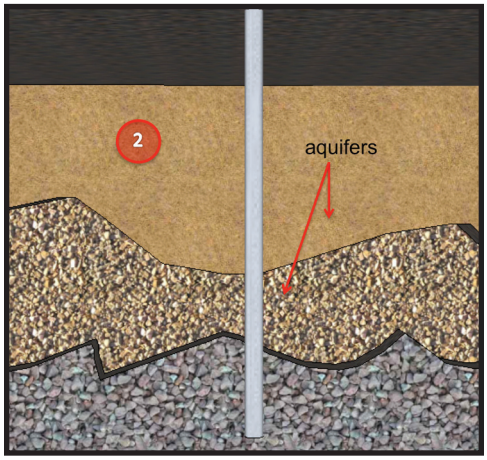
A variety of surface disturbances are associated with *in situ* oil sands operations. For instance, underground formations and the location and extent of the oil sands resource are assessed with 2-D and 3-D seismic testing, which require that seismic lines be cut through forests. Forests also are clear-cut for well-site preparation, construction and installation of infrastructure for bitumen extraction, processing, and transportation, and laying of roads. The total area leased for *in situ* operations in 2005 amounted to 11 times the size of mineable oil sands.[54] When ecological edge effects and the disturbance footprint from natural gas exploration and development needed for steam production and bitumen upgrading are included, the overall surface disturbance of an *in situ* oil sands operation is greater than for surface mining of the same amount of bitumen from shallow oil sands deposits (see Figure 4).[55]

ACTIVITY OR FOOTPRINT TYPE	LAND AREA (HA)
Total *in situ* leases	3,568,000 ha
Total projected forest cleared	296,000 ha
Total projected roads built	30,000 km

FIGURE 4. Land disturbance associated with *in situ* oil sands development in north-central Alberta is greater than mining, per-barrel of bitumen produced, when total land area and edge effects of exploration and development are included for both SAGD and natural gas production upon which it relies. SOURCE: Google Earth, 2011.

3.4.2 UNQUANTIFIED GROUNDWATER FOR SAGD

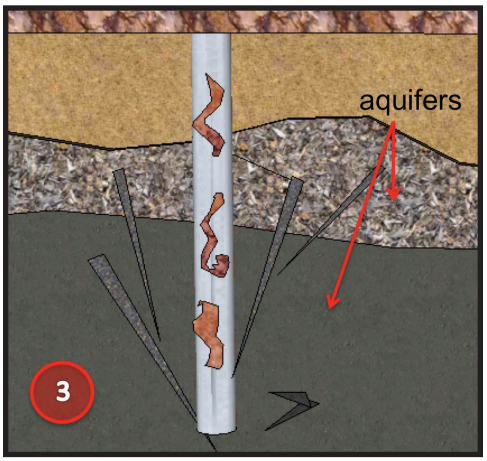
Water wells drilled to supply freshwater for SAGD operations typically range from 75 m to 350 m in depth. Despite the existence of many industrial water wells spread across north-central Alberta, publicly available information on source water used in *in situ* operations is sparse. Alberta Environment is the primary government agency responsible for designing and implementing the groundwater and surface water frameworks under the Lower Athabasca Regional Plan. However, although Alberta Environment collects information on the depths of wells, no government agency can identify the aquifer from which a particular well is withdrawing non-saline water. Also, because Alberta Environment only collects records of wells that provide groundwater with a salinity of up to 4000 mg/L TDS (total dissolved solids), nobody knows the total number of groundwater wells used for *in situ* oil sands operations or the total



volumes or pumping rates of groundwater well production. To date, there has been no integrated assessment and minimal monitoring of the quality and quantity of groundwater used in the oil sands region. While Alberta has created a groundwater management framework, it would take years before an understanding of groundwater resources would be gained even if a detailed, large-scale assessment of groundwater in the oil sands region were immediately designed, funded, and implemented.[56]

The greatest risk to groundwater in the oil sands region is the cumulative effects of *in situ* oil sands operations, which are unknown largely because the regional supply and quality of groundwater for the oil sands region also are unknown.[57] Regional groundwater varies in quality, ranging from freshwater to more saline than ocean water.[58] As a result, finding reliable pockets of fresh groundwater for SAGD can be uncertain, and these pockets may be connected to surface water via shallow aquifers. Similarly, the availability of reliable sources of slightly saline water also can be uncertain. As discussed in the Nexen Case Study, the uncertainty in groundwater quality and long-term availability creates a strong economic incentive for industry to quietly pursue access to fresh water for SAGD projects from surface sources, after receiving approvals based on saline groundwater use.

3.4.3 *IN SITU* AND LEAKING WELLS



A variety of well types are used in the life of an *in situ* oil sands project, including groundwater wells for steam production and processing water, and wells for initial testing and continuing monitoring of the state of the bitumen resource and its recovery. An accurate assessment of the number of wells that have been reclaimed in Alberta has not been done, and therefore it remains unknown.[59] When a well is operational and after it has been abandoned it is important that it is fully sealed and cased at the appropriate depths, to avoid continuing contamination of aquifers and formations through which the well has been drilled. Abandoned wells therefore become liabilities if they are not properly sealed and maintained.[60] Public data gathered in 2006 from the ERCB suggests that more than 18,000 wells drilled for heavy oil and gas in Alberta were leaking, of which 25 percent were due to surface casing failures.[61] We are uncertain of the total number of wells drilled for *in situ* oil sands operations and the number of wells that are leaking, however Oliphant (2010) suggests this rate is only rising and an assessment has not be done since 1988.[62] Cumulatively, this represents a huge risk to regional groundwater.

For wells deeper than 150 m, casings must be properly sealed with cement to keep water, bitumen, and chemicals associated with SAGD operations contained in the oil sand deposits. Improperly sealed well casings therefore pose a threat to groundwater quality in the formations and aquifers through which the wells are drilled, because the wells act like perforated straws, forming conduits for all kind of fluids (salt water, oily water) to migrate to freshwater aquifers.

After being perforated by a large number of wells, the cap-rock that overlays bitumen-bearing formations (and which is assumed to be impermeable) also may allow the vertical mixing of fluids of different qualities present above and below it. Two critical factors affecting groundwater quality therefore are the very large number of wells being drilled and their long effective life-spans as potential pathways for vertical fluid movement. Since Alberta has become a major oil and gas producer, hundreds of thousands of wells have been drilled, and a large number of these wells have begun to leak. Undoubtedly, the number of leaking wells

will continue to grow in the future, as degradation of the sealing material and corrosion of casings continues. These leaking wells will create havoc in groundwater aquifers, because of the drop of pressure in the shallow aquifers due to their perforation and the contamination of freshwater aquifers when fluids of lower quality enter them (Figure 5).

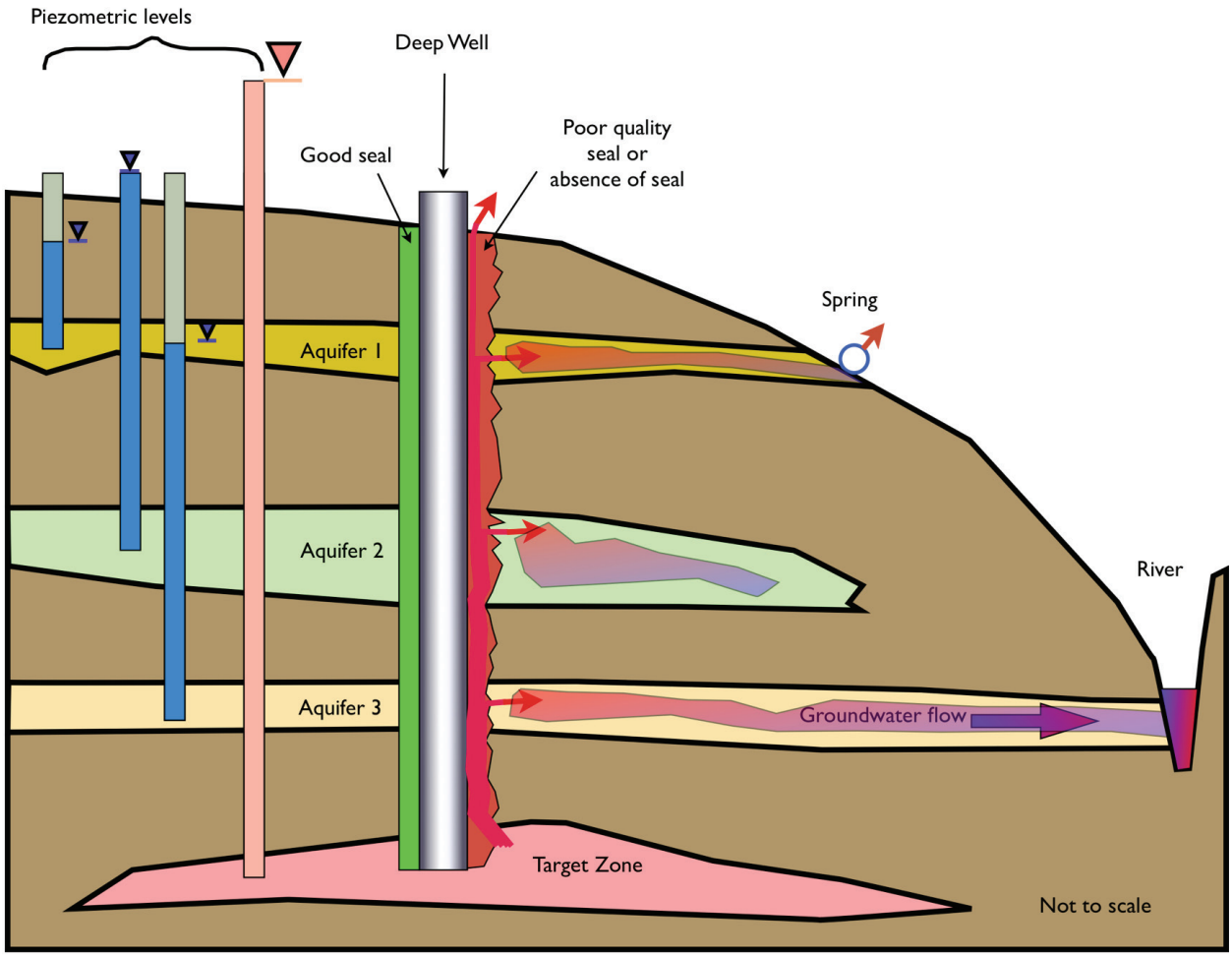
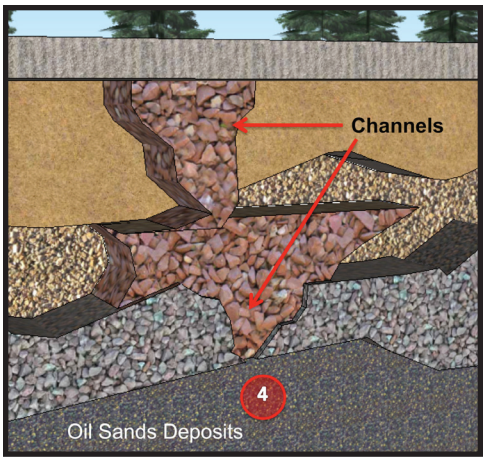


FIGURE 5. Leaking well seals can result in contamination of aquifers between the bitumen bearing formations and the surface. SOURCE: Wendling, Gilles 2010.

In addition to changes in the flow and quality of groundwater because of contamination and perforation, increases in the temperature of groundwater in contact with the steam injection wells also can change flow rates and result in the release of a number of geologic elements, including arsenic, leading to further contamination of aquifers in the oil sands region.[63]

3.4.4 BURIED CHANNELS



The McMurray Formation is the primary geological formation holding oil sands deposits in Alberta. This formation is tilted, buried deeply in the west and rising to the surface in the east. For this reason, the McMurray Formation is exposed along the Athabasca River, which is why most of the surface mining for oil sands is situated in an area north of Fort McMurray (see Figure 6).[64] Because there also are many unmapped groundwater routes located in buried channels of permeable soils overlaying bitumen deposits (also referred to as tunnel or buried valleys), oil sands development in this region is very risky because of its potential impacts to groundwater aquifers.[65]

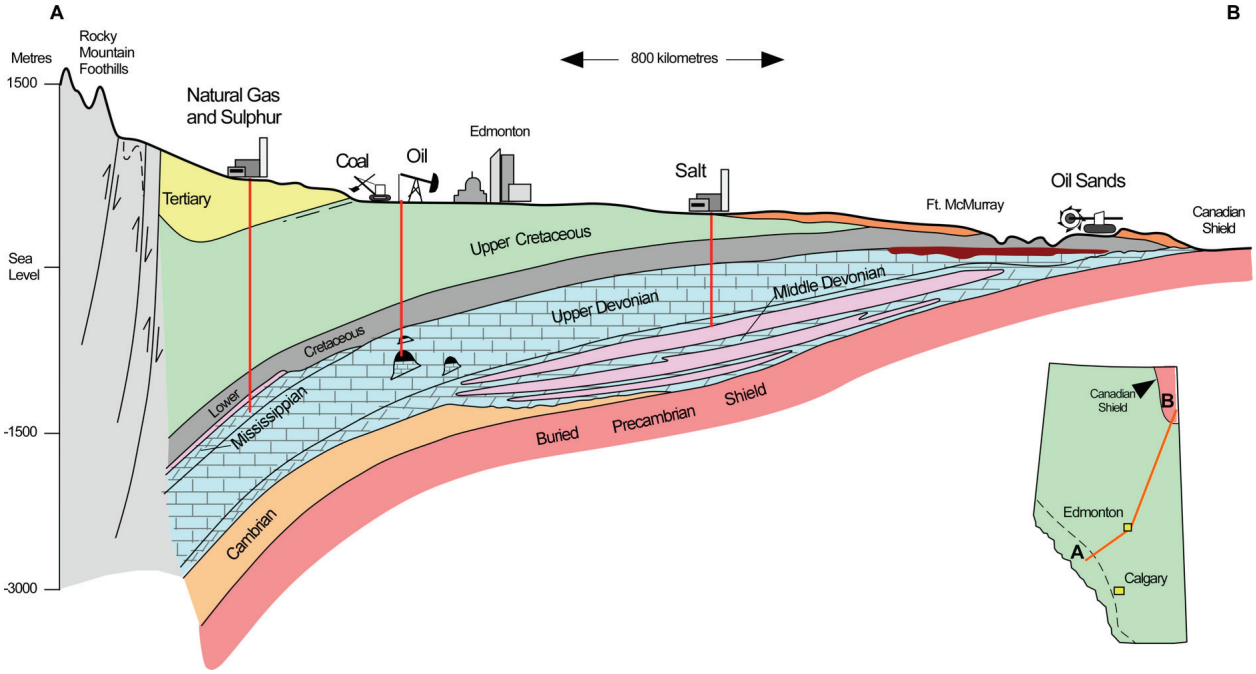


FIGURE 6. Changes in geological formations from west-central to north-eastern Alberta, with oil sands deposits.
SOURCE: With permission from Energy Resources Conservation Board/Alberta Geological Survey and Royal Alberta Museum 2010.

Some of these buried channels are sources of high quality drinking water, and their locations and contact with bedrock are complex.[66] In addition, these channels likely overlap or connect, and can act as natural connections between groundwater and surface water (Figure 7).[67] As might be expected, the highest density of wells associated with oil sands development north of Fort McMurray are in and around the mineable oil sands region surrounding the Athabasca River and its tributaries, and correspond closely with important regional groundwater flows that discharge into local rivers (Figures 8 and 9). Aquifer and surface water connectivity in the oil sands region and elsewhere needs to be well understood if groundwater is expected to be managed sustainably and cumulative impacts of development are to be properly assessed and minimized.

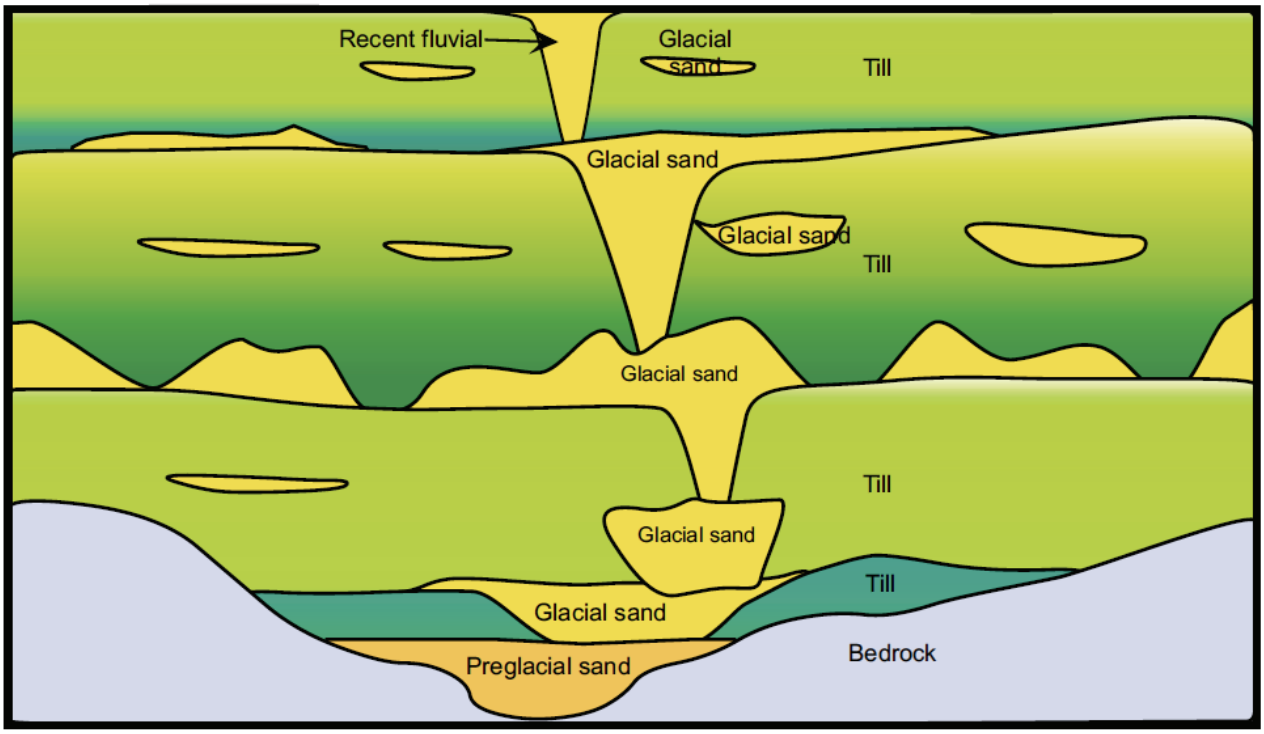


FIGURE 7. Different layers of soil overlaying cap-rock often contain overlapping buried channels or connections of porous sand that create vertical paths for groundwater between aquifers, and to or from surface waters. SOURCE: Adrianshek, 2003, with permission from the ERCB/AGS, 2011.

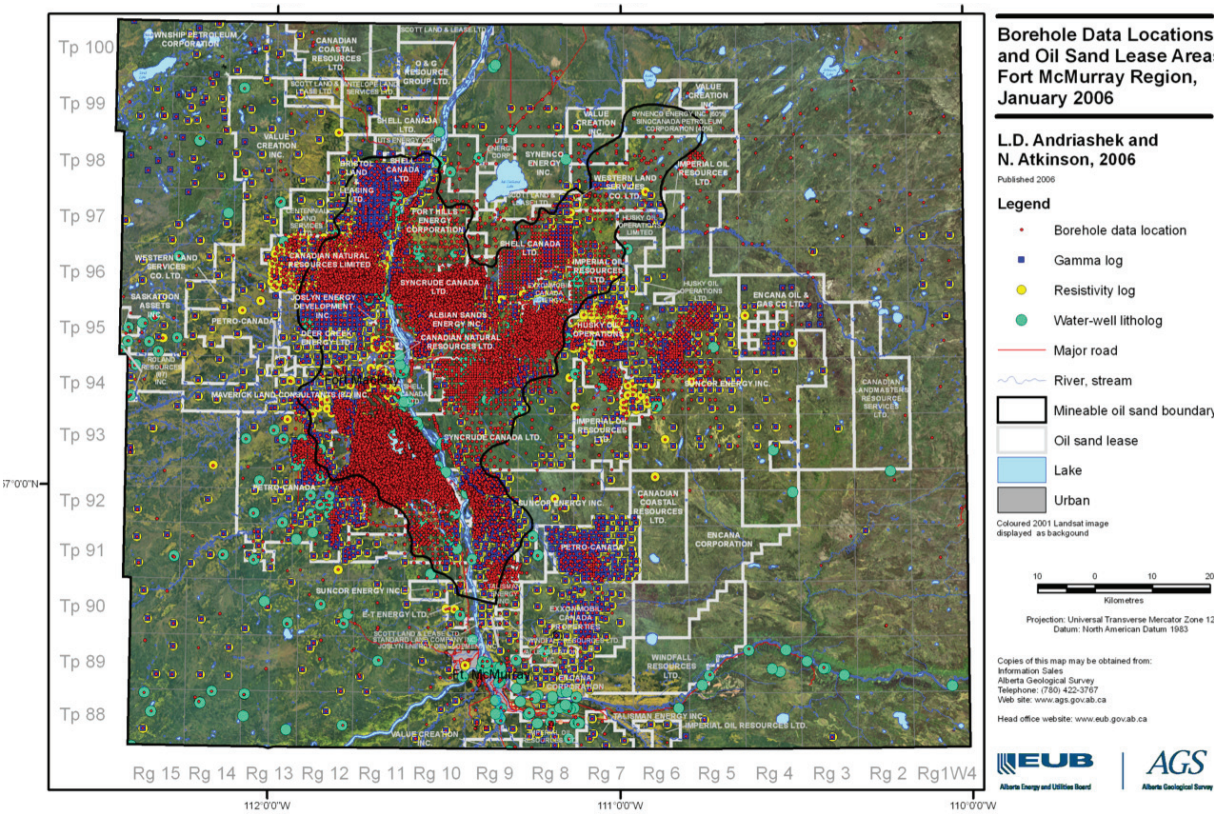


FIGURE 8. Location of wells associated with oil sands development north of Fort McMurray. SOURCE: With permission from ERCB, 2010, in Adrianshek 2007.

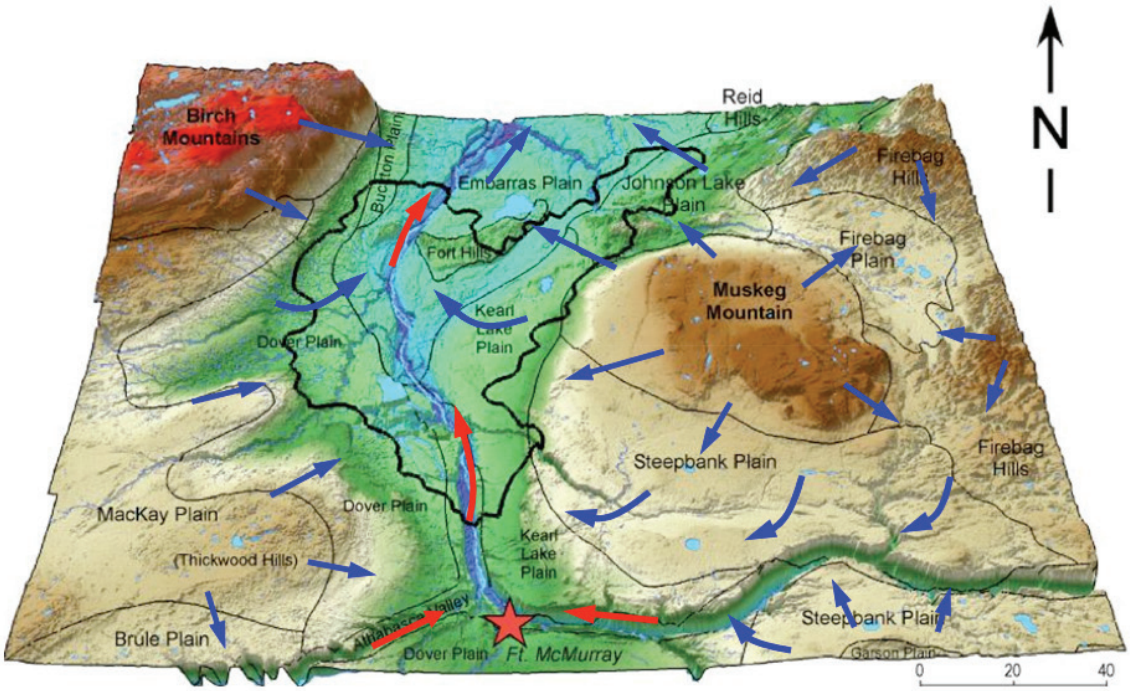
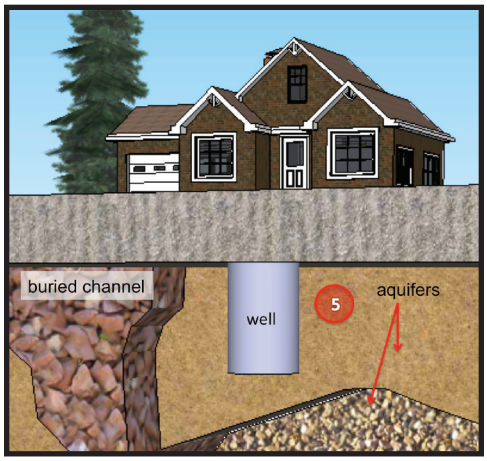


FIGURE 9. Regional groundwater flow north of Fort McMurray moves from highlands into the valleys and discharges into the Athabasca River and its major tributaries, which is where the majority of oil sands development and associated wells are located in this region. SOURCE: With permission from Cumulative Effects Management Association, 2010

3.4.5 SHALLOW AQUIFERS

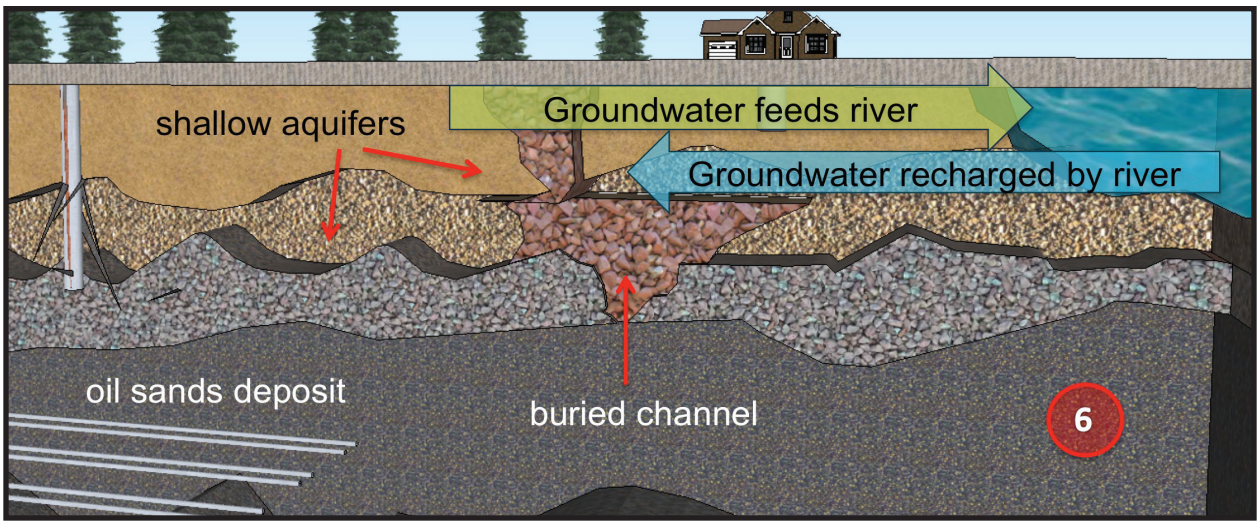


Shallow aquifers generally are located above oil sands deposits, and are separated from them by uneven layers of soils containing clay and silt (called aquitards) and an uneven horizon of shale known as cap-rock. As described above, shallow aquifers are closely connected to rivers, lakes, and wetlands. Lakes often form in areas of low topography where aquifers discharge to the surface or are recharged by surface waters, and the base flow of rivers - such as occurs during winter when there is little rain or snowmelt - consists predominantly of groundwater. The most obvious risk of groundwater pumping from *in situ* oil sands development is the depletion of aquifers. For example, groundwater pumped from an aquifer near the Muskrat River Mine resulted in a 40 m drop of the local water table.[68]

As mentioned above for risks associated with wells and buried channels, the risks to shallow aquifers include contamination with increased concentrations of chemicals associated with increases in groundwater temperature, fluid migrations due to drilling or faulty casing and sealing of wells, and the depressurization or depletion of aquifers.

3.4.6. CONNECTION TO RIVERS AND LAKES

Very little is known about the complimentary and highly variable movement of water between groundwater aquifers and surface waters such as rivers, lakes, and wetlands in Alberta. For example, a recent study described two lakes close to Fort McMurray that receive 0.5% to 14% of their annual water supply from groundwater sources.[69] The Wiau Channel is the largest shallow aquifer in the oil sands region that is connected to other channels, and it discharges groundwater directly into the Athabasca River. Therefore, anything that affects groundwater in channels connected to the Wiau Channel may also affect the Athabasca River. The total sustainable supply of groundwater that can be withdrawn for *in situ* oil sands operations therefore also depends on the contributions of local or regional groundwater aquifers to surface waters. Any development activities that affect either the quantity or quality of groundwater in the Wiau or other shallow channels will likely contribute to cumulative negative effects of development on regional surface waters. Because groundwater and surface water are very closely connected, it is important to understand these connections in order to properly manage both surface and groundwater.



Shallow aquifers and channels feed rivers, lakes and wetlands in the winter, and generally shallow aquifers are recharged in the summer.

3.4.7 SUMMARY OF RISKS

Based on an assessment of aquifer recharge and discharge in the Lower Athabasca, Christina, and Clearwater River basins, and the geology and groundwater flow patterns in the McMurray Formation and the Mannville Group (*i.e.*, the main formations targeted for SAGD bitumen extraction), there are a number of important risks SAGD poses to groundwater:[70]

- finding and sustaining the large volumes of fresh water necessary for steam production, without jeopardizing groundwater resources in the area;
- safe disposal of waste water from SAGD operations[71];
- protecting groundwater, energy and potential mineral resources from contamination, because of the uncertain integrity and safety of SAGD and injection operations, and poorly cemented and improperly completed or abandoned wells; and
- the potential for large-scale groundwater movement between deep and shallower aquifers via highly permeable abandoned steam chambers.

3.4.8 POOR UNDERSTANDING OF GROUNDWATER IN THE OIL SANDS REGION

One of the main problems contributing to the risks associated with the increasing amount of SAGD development in Alberta's oil sands region is the lack of understanding of regional groundwater dynamics. According to the Cumulative Effects Management Association (CEMA)[72], a suite of problems associated with the continuing lack of monitoring and assessment of groundwater resources contributes to increased risk, including:[73]

- lack of sufficient temporal data in existing monitoring wells to determine historical trends for key indicators;
- limited monitoring coverage outside of the active mineable oil sands area;
- unknown degree of connectivity between certain aquifers and major water bodies (*e.g.*, Clark Channel, Kearl Channel, Fort Hills Channels) and wetlands;
- poorly assessed hydraulic characteristics of most major channels;
- lack of geological data for most buried valleys (*i.e.*, is it sand or till?);
- lack of understanding of surficial geology on western side of study area;
- limited understanding of cross formational flow and groundwater surface water interactions;
- contribution from bedrock formations water to natural water bodies like the Athabasca River (*i.e.*, loading of natural constituents versus industrial contamination);
- vertical variation of quality conditions in discrete water-bearing intervals and potential effects of bedrock water chemistry on near-surface sands and buried channels/valleys;
- insufficient information on Grand Rapids, Wabiskaw and Methy Formations to facilitate vulnerability mapping and management classification scheme; and
- limited information on the distribution of basal McMurray Formation beyond the central portion of the regional study area (*i.e.*, further west and east).

According to CEMA, one of the more comprehensive regional hydrogeological studies is still more than 30 years old.[74] As pointed out in the recent report on environmental monitoring commissioned by the Royal Society of Canada, this is indicative of the lack of an integrated regional groundwater framework for the oil sands region.[75]

Apparently, the accident at Shell Canada's Muskeg River Mine described above is the first of its kind, in which aquifer perforation has occurred during an oil sands mining operation. A spokesman from the ERCB characterized the source of the problem as a geological anomaly in the "naturally occurring concrete" at the bottom of the mine pit.[76] However, rather than a homogeneous layer of cap rock that seals and separates surface bitumen deposits from deep groundwater, as discussed above buried channels have been identified as forming hydraulically connected labrynth-like patterns within these layers. In addition, because buried channels are so narrow they are difficult to detect with standard borehole assessments of sediment and hydrology.[77] Thus, these narrow vertical channels can provide undetected direct vertical pathways for water or steam movement, akin to climbing or descending a set of stairs between deep bedrock and the surface.[78]

Buried channels are often not planned for, detected, or adequately investigated when found. "[I]n the surface mining area, they can act as natural pathways for the subsurface migration of fluids from overlying tailings ponds" and "[t]his geologic feature is clearly one that must be avoided in the design and approval of tailings ponds."[79] If buried channels can connect to surface water or tailings ponds fluids, then it is reasonable to conclude that buried channels might also facilitate upward movement of saline water from deep saline aquifers. Because saline or brackish groundwater used in *in situ* oil sands operations is disposed of via underground injection, undetected hydraulic interconnections like buried channels are problematic for long-term storage of industrial wastes. Therefore, a detailed understanding of subsurface hydraulic connectivity such as buried channels and how formations are connected is critical for quantifying and understanding the potential and risks for underground disposal of injected saline wastewater to shallow aquifers and surface waters.[80]

The two case studies describing the accidents with Total and Shell in this report provide clear examples of the kinds of risks associated with *in situ* oil sands extraction. High-density 3-D seismic and groundwater mapping techniques used as the industry standard are evidently insufficient to adequately assess either the local stability of cap-rock, or the local presence and location of hydraulically connected permeable formations in the soils overlaying it or at the base of mineable oil sands formations. According to the Royal Society's commissioned report, groundwater flow modeling performed as part of project environmental impacts assessments is only local in scale and limited in utility to the local area in the vicinity of a particular project. There has been no conceptual hydrogeological model produced for the entire oil sands region. Consequently, both the amount of regional groundwater available for use in *in situ* bitumen extraction and the cumulative effects of such use on regional groundwater aquifers and surface waters remain unknown.[81]

TECHNICAL PROBLEMS WITH SAGD BITUMEN EXTRACTION

In addition to the geological and hydrogeological uncertainties associated with SAGD sites, the methods and technologies deployed for SAGD bitumen extraction present their own risks. Despite these risks, SAGD is promoted as a proven technology and SAGD projects are continually approved by the ERCB or Joint Review Panels. Yet, the efficacy and safety of SAGD technology are uncertain, as disclosed by Total in their after-action report on the accident described in Case Study 1:[82]

> **Although proven by several successful pilot / small scale applications, SAGD is not yet fully mature. A significant amount work is still necessary to fine tune equipments and procedures required to operate safely SAGD projects for the long term in the fairly wide range of conditions foreseeable in Alberta (and beyond).** Considering such large range of conditions, it is difficult to lay out precise and generic recommendations but it is clear that any project should address the following issues:
>
> i. Seal: characteristics including maximum admissible pressure.
>
> ii. Well design: casing, cement, and completion.
>
> iii. Operating pressure: philosophy including during startup, expected surface heave.
>
> iv. Overall steam confinement monitoring: philosophy (including link with surface layout design) and means.
>
> v. It is expected that these issues be challenging as a whole in some areas (Joslyn being one) while they may be less of a concern in others. (emphasis added)

Since the explosive steam eruption described in this report, Total has abandoned its Joslyn Creek SAGD project.[83] According to the ERCB, the closure was due to the poor economics associated with, among other things, permitted operating pressure restrictions and monitoring requirements for the project. If an *in situ* oil sands project is not viable when regulatory restrictions and permits are attached to its approval and permits, then such inviable elements in a project should be detected prior to its approval. This was not the case in the Total's Joslyn Creek and Nexen's Long Lake SAGD projects, which suggests that regulatory oversight and SAGD project assessment at the approval stage in Alberta are insufficient.

SAGD is still considered an immature technology, requiring significant development of equipment and procedures to make large-scale and long-term projects safe under diverse field conditions. The fact that Total breached its permitted injection and operating pressure limits indicates a lack of internal and external operational oversight. Either Total failed to recognize the initial evidence of fracturing more than a month before the explosion, or simply ignored it. Combined with the lack of understanding of regional groundwater connectivity, quantities, or impacts, all of these problems paint a picture of SAGD as a high risk oil sands development technology that operates on the basis of numerous unsupported geological, hydrological, technological, and safety assumptions. Equally important, the first two case studies described here point to insufficient risk management approaches and practices employed by the Government of Alberta, including insufficient demands for pre-approval assessment of risks to groundwater associated with *in situ* oil sands development. Rather than managing *in situ* oil sands development on the basis of clearly identifying and quantifying risks associated with it, it is being managed on the basis of a largely incomplete, unmonitored, and undeveloped knowledge of groundwater resources upon which it relies and for which it poses substantial risk, leaving us unprepared to deal with serious problems until after they arise and are detected.

RECOMMENDATIONS

Our recommendations for the management of groundwater use and impacts of SAGD and other oil sands extraction processes fall into two categories. The first relates to adoption of improved groundwater assessment and monitoring programs that would enable an understanding of regional groundwater dynamics and sustainable yields, and the second to the enforcement of protective environmental standards.

The Government of Alberta should:

1. Create an independent scientific panel to a) design a scientific plan that will enable the determination of pre-development baselines for surface and groundwater quality and quantity and sustainable yields from local and regional aquifers, and b) design a groundwater assessment and monitoring plan that will permit the detection of significant changes in groundwater quality and flow dynamics and patterns, and the distinction between natural and human causes for any identified changes in groundwater quantity or quality.

2. Commit to adopting, funding, and fully implementing a scientific groundwater assessment and monitoring program described in Recommendation #1, thereby ensuring that a sufficiently detailed understanding of the hydrogeology and groundwater dynamics is acquired to properly manage and limit oil sands development and protect groundwater and surface water resources.

3. Significantly increase in-house and external research capacity and funding to quantify and qualify groundwater resources in Alberta.

4. Expand groundwater assessment and monitoring to include not only all non-saline aquifers but also all saline aquifers with concentrations between 4,000 and 10,000 mg/L. This will contribute to a better understanding of the effects of industry use of saline groundwater and injection of saline waste materials into deep aquifers and formations.

5. Within a single government ministry, collect, organize, and integrate all industry data collected to date for saline and non-saline water use, perform (as much as possible) an up-to-date cumulative regional assessment of oil sands extractors' groundwater use and impacts, and make both the data and cumulative assessment freely accessible, searchable, and available to the public.

6. Develop and implement, as soon as possible, science-based industry performance indicators related to groundwater quality, quantity, and sustainable yield, and regulatory triggers for government responses to either anticipated or identified impacts on either groundwater quality or dynamics.

7. Immediately design and adopt interim indicators and limits that are based on the precautionary principle and the best available current understanding of local and regional sustainable groundwater, to prevent harm to groundwater resources while more appropriate indicators and triggers are being developed as per Recommendation #6.

8. Adopt, regulatory and management responses as part of the Lower Athabasca Regional Plan and other relevant laws, policies, guidelines and ERCB directives, that include the requirement to stop groundwater extraction or steam or waste injection when identified groundwater indicator thresholds or triggers are reached or surpassed.

9. Include in all approvals for oilfield or waste injection and appropriate governing regulations the operational requirement to immediately report to the primary governing or regulatory body any evidence of unexpected significant geological anomalies or primary fractures caused by injection of steam, water, chemicals, or waste products, and adopt regulatory and industry response triggers that impose immediate cessation of local injection operations in such an event, when the potential effects may compromise the integrity and utility of either aquifers or bitumen-bearing formations.

10. Develop a publicly accessible and searchable database of all wells used for *in situ* operations, detailing which wells have been reclaimed and which have not, and coordinate and impose a shared financial responsibility for all operators for sealing and maintaining orphaned wells.

ENDNOTES/REFERENCES

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10 AMEC Earth & Environmental, *Water for Life: Current and Future Water Use in Alberta* (Edmonton, Alberta: AMEC Earth & Environment, 2007), at 461. Prepared for Alberta Environment.
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12 Deutsch, C.V. and J. A. McLennan, Guide to SAGD (Steam Assisted Gravity Drainage) Reservoir Characterization Using Geostatistics (Edmonton, Alberta, Centre for Computational Geostatistics, 2005), www.uofaweb.ualberta.ca/ccg/pdfs/Vol3-IntroSAGD.pdf (accessed March 21, 2011) cite diameters as large as 3.3m, whereas Gosselin *et al.*, *supra* note 4 at 45, reports well bores with diameters as small as 0.2 m.
13 Gosselin *et al.*, *supra* note 4 at 45.
14 B. Wilson, B. Stelfox, and M. Patriquin, *SEWG Workplan Facilitation and Modelling Project Data Inputs and Assumptions*, (Edmonton, Alberta: Silvatech Group and Cumulative Environmental Management Association, 2008), at 45-48.
15 *Supra* at 38.
16 Marc Huot, Pembina Institute, Personal Correspondence, April 6, 2011. Life of SAGD projects are expected to be: Cenovus Christina Lake — 25 years; Cenovus Foster Creek — 25 years; Husky Tucker — 5 years; JACOS Hangingstone — 20-25 years; Suncor McKay River — 20 years; and Suncor Firebag — 30 years.
17 Wilson, Stelfox, and Patriquin, *supra* note 14 at 38.
18 AMEC Earth & Environmental, *supra* note 10 at 461.
19 In 2006, the Government of Alberta released a draft plan to *Water Conservation and Allocation Policy for Oilfield Injection*, but terms for recycling rates and saline water use have yet to be issued under this directive.
20 AMEC Earth & Environmental, *supra* note 10 at 621. The AMEC report states uncertainty in the effect of the policy on water quantity, and the relationship between geology and source water are discussed in M. Griffiths, A. Taylor, and D. Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* 1st Edition (Drayton Valley, Alberta: The Pembina Institute, 2006), at 81.
21 Gosselin *et al.*, *supra* note 4 at 46.
22 M. Griffiths, A. Taylor, and D. Woynillowicz, *supra* note 20 at 80-81. Recycling rates for *in situ* depend upon the quantity and quality of water used and generally are presented at rates of 90-95%. However, this rate is misleading, because the Energy Utility Board (EUB)'s method for calculating recycle rate is based solely on the amount of steam produced, the amount of non-saline water that is used, and the amount of produced water that is recovered with bitumen.
23 Griffiths, Taylor, and Woynillowicz, *supra* note 20 at 38-39.
24 *Lower Athabasca Region Groundwater Management Framework*, Alberta Environment (March 31, 2011). Respectively, these can be found at http://environment.alberta.ca/03422.html and http://environment.alberta.ca/documents/Groundwater_Management_Framework_April_1_-Final.pdf (accessed April 29, 2011).
25 *Supra* at 2.
26 *Supra* at 5-6.
27 *Supra* at 13.
28 *Supra* at 15-16.
29 *Supra* at 19.
30 *Supra* at 17-18.
31 Government of Alberta, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf.
32 *Supra* at 2.
33 *Supra* at 1.
34 *Ibid.*
35 *Supra* at 3.
36 This priority is mandated by the *Oil and Gas Conservation Act*, RSA 2000, the purpose of which is to effect resource conservation and prevent waste of oil and gas resources [s. 4(a); http://www.canlii.org/en/ab/laws/stat/rsa-2000-c-o-6/latest/rsa-2000-c-o-6.html]. Most people might interpret this as indicating a desire to preserve the resource to the benefit of Albertans and to prevent waste or environmental harm. However, it instead refers to the need to maximize energy resource recovery, and prevent waste in the form of resources that might otherwise be recoverable but that are left in the ground either intentionally or as the result of industry practices that may themselves inadvertently reduce the amount of resource able to be recovered. The ERCB typically issues directives that reflect this government priority and are intended to promote maximal recovery or extraction of energy resources by industry operators/producers. Unfortunately, this legislated and enforced prioritization of maximal resource recovery often butts up against the need to minimize environmental harm. In the end, it is usually maximal recovery that takes priority over prevention of environmental harm.
37 *Water Conservation and Allocation Guideline for Oilfield Injection*, Government of Alberta (2006), at 8; http://environment.gov.ab.ca/info/library/7700.pdf (accessed 3 May 2011).
38 Alberta Environment, "Facts About Water in Alberta," December 2010, 24, http://environment.gov.ab.ca/info/library/6364.pdf (accessed February 4, 2011).
39 Seneka, M., "Summary Report: Water Supply Assessment for Alberta," prepared for Alberta Environment, June 2009 (Edmonton, AB: Government of Alberta), at 8-9.
40 Sophocleous, M. "From safe yield to sustainable development of water resources — the Kansas experience." *Journal of Hydrology* 235 (2000): 27-43.
41 The term "cap-rock" generally refers to the impermeable layer of rock that overlays the geological formation in which an oil sands deposit is found and from which bitumen is extracted. Theoretically, the cap-rock confines the effects of SAGD extraction to the oil sands formation and acts as a barrier to movement of steam, water, and chemicals to the aquifers and other geological formations above it.
42 Energy Resources Conservation Board, "Total E&P Canada Ltd. Surface Steam Release of May 18, 2006 Joslyn Creek SAGD Thermal Operation: ERCB Staff Review and Analysis" (February 11, 2010), iv; http://www.ercb.ca/docs/documents/reports/Total_Canada_Report_JoslynSteamRelease_2010-02.pdf.
43 *Ibid* at v.
44 *Ibid.*

45 Gosselin *et al.*, *supra* note 4 at 139 and Figure 8.7 at 141; Andriashek, L. D. 2003. Quaternary geological setting of the Athabasca Oil Sands (*In situ*) area, northeast Alberta; Alberta Energy and Utilities Board, EUB/AGS Earth Sciences Report 2002-03.
46 Campbell, Carolyn, "*In situ* Tar Sands Extraction Risks Contaminating Massive Aquifers," *Wild Lands Advocate*, Vol. 16, No. 5 (Calgary, AB: Alberta Wilderness Association, 2008).
47 Hanneke Brooymans, "Shell's mined-out pit at Muskeg River flooding with salt water," *Edmonton Journal*, December 9, 2010, http://www.edmontonjournal.com/business/Shell+mined+Muskeg+River+flooding+with+salt+water/3948718/story.html.
48 Louis Grelow, ERCB, personal communication, May 3, 2011.
49 Nexen Inc, "Long Lake Source Water Project: Application to Fisheries and Oceans Canada, Transport Canada, and Alberta Environment" (Calgary, AB: Nexen, 2010), Application Numbers 001-00267465 and 001-00267466.
50 Alberta Energy and Utilities Board, "ERCB: Application 1080609; Notice of Filing Athabasca Oil Sands Area; Application No. 1080609 and No. 200354; Alberta Environment Environmental Protection and Enhancement Act Application No. 001-137467 and Environmental Impact Assessment Report Water Act Application No. 002-00079331 (Calgary, AB: OPTI Canada Inc), A3-12, at 56. See also ERCB File 1080609, Approval No. 9485.
51 Nexen Inc, "Long Lake Source Water Project," *supra* note 49 at 21.
52 *Ibid.*
53 *Ibid.*
54 R. Schneider and S. Dyer, *Death by a Thousand Cuts: Impacts of In situ Oil Sands Development on Alberta's Boreal Forest*, (Edmonton, AB: Canadian Parks and Wilderness Society and the Pembina Institute, 2006), at 11. Edge effects are the negative ecological effects that extend into the forest adjacent to industrial footprints, because of such factors as noise, human presence, and the close proximity between formerly sheltered forest habitat and open spaces.
55 S. Jordaan, D. Keith, and B. Stelfox, "Quantifying land use of oil sands production: a life cycle perspective," *Environmental Research Letters*, Vol. 4 (2009), http://iopscience.iop.org/1748-9326/4/2/024004 (accessed April 15, 2011). Edge effects are essentially the area surrounding *in situ* operations which is a measurement to understand the fragmentation of ecosystems.
56 CEMA (2010), *Athabasca Oil Sands (AOS) Groundwater Quality Study and Regional Groundwater Quality Monitoring Network Study*, Report prepared by Worley Parsons for the Groundwater Working Group, Cumulative Environmental Management Association, at 10.
57 Gosselin *et al.*, *supra* note 4 at 136; and L. Dowdeswell *et al.* (Oil Sands Advisory Panel), *A Foundation for the Future: Building an Environmental Monitoring System for the Oil Sands*, report submitted to the Minister of Environment (Ottawa, ON: Environment Canada, 2010), at 13; http://www.ec.gc.ca/pollution/default.asp?lang=En&n=E9ABC93B-1 (accessed January 24, 2011).
58 S. Grasby and Z. Chen, "Subglacial recharge into the Western Canada Sedimentary Basin — Impact of Pleistocene glaciation on basin hydrodynamics, *Geological Society of America Bulletin* 117(¾) (2005): 500-514. Salinities range from 20 to 320 grams per litre. The salinity of freshwater is less than 1 gram per litre, whereas the ocean is generally 35 grams per litre.
59 Water Matters, "Webinar: Groundwater Basics: Q1. About reclaiming unused wells, are there numbers of how many wells have been reclaimed? Are there guidelines to reclaim wells? What are the effects of not reclaiming unused wells?," June 21, 2007, http://www.water-matters.org/pub/webinar/groundwater-basics (accessed May 8, 2011).
60 Of course, the same applies for wells in use during an *in situ* project's operational phase. See C. Campbell, *supra* note 46.
61 D.C. Bexte *et al.*, "Improved cementing practice prevents gas migration: Cementing improvements were combined to reduce failures in shallow heavy oil wells," special focus in Drilling and Well Completion of *World Oil*, June 2008.
62 Oliphant, Scott, Well Casing Corrosion and Cathodic Protection, Northern Area Western Conference February 15 -18, 2010, Paper from Proceedings, http://nacecalgary.ca/links.htm (accessed May 10, 2011).
63 Gosselin *et al.*, *supra* note 4 at 142. See also J. Fennell, *Effects of Aquifer Heating on Groundwater Chemistry with a Review of Arsenic and its Mobility* (PhD dissertation, University of Calgary, Department of Geoscience, 2008).
64 O. P. Strausz and E. M. Lown, The Chemistry of Alberta Oil Sands, Bitumens and Heavy Oils (Calgary, AB: Alberta Energy Research Institute, 2003), as cited in E. Kelly *et al.*, "Oil sands development contributes polycyclic aromatic compounds to the Athabasca River and its tributaries," *Proceedings of the National Academy of Sciences* 106 (2009): 22346–22351, www.pnas.org_cgi_doi_10.1073_pnas.0912050106. See also L. N. Adrianshek and N. Atkinson, *Buried Channels and Galcial Drift Aquifers in the Fort McMurray Region, Northeast Alberta*, Alberta Energy and Utilities Board, EUB/AGS Earth Sciences Report 2007-01, 80; http://www.ags.gov.ab.ca/publications/abstracts/ESR_2007_01.html (accessed November 1, 2010).
65 According to Gosselin *et al.*, *supra* note 4 at 138, this area north Fort McMurray is an area in which overlapping buried channels are connected to surface waters, which requires co-management of surface water resouces with groundwater extraction and detailed understanding of connections prior to *in situ* or waste injection.
66 Andriashek and Atkinson, *supra* note 64 at 6.
67 Gosselin *et al.*, *supra* note 4 at 138, and Adrianshek and Atkinson, *supra* note 64 at 2.
68 Gosselin *et al.*, *supra* note 4 at 112.
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71 According to Barson *et al.*, *supra*, the basal McMurray aquifer is being used for deep injection of waste water in several places because it is the shallowest and cheapest to use for this purpose. However, it is not an appropriate long-term solution, because it outcrops along the Christina and Athabasca river valleys and is not capable of sustaining the volumes of waste generated by numerous large-scale oil sands operations that will demand permanent disposal. The overlying aquitard that separates it from other aquifers also owes its impermeability to the bitumen saturating it rather than impermeable shale rock present elsewhere. As the bitumen is extracted, this layer will become less effective as a barrier to hydraulic connectivity and vertical flow of wastewater.
72 CEMA is a stakeholder group that includes industry and government representatives and is in charge of assessing and managing cumulative effects of oil sands development.
73 CEMA (2010), *supra* note 56 at 79.
74 *Ibid* at 21.
75 Gosselin *et al.*, *supra* note 4 at 117.
76 Hanneke Brooymans, *supra* note 47.
77 Gosselin *et al.*, *supra* note 4 at 138. See also Andriashek and Atkinson, *supra* note 64.
78 *Ibid.*
79 Gosselin *et al.*, *supra* note 4 at 139.
80 Gosselin *et al.*, *supra* note 4 at 138. See also Parks, K. *et al. Regional Groundwater Resource Appraisal, Cold Lake-Beaver River Drainage Basin, Alberta* (Alberta Energy and Utilities Board, Alberta Geological Survey, Special Report 074, 2005.)
81 Gosselin *et al.*, *supra* note 4 at 136.
82 Total E & P Canada Ltd., "Summary of investigations into the Joslyn May 18th 2006 Steam Release," TEPC/GSR/2007.006, at 9; http://www.ercb.ca/docs/documents/reports/Total_Canada_Report_JoslynSteamRelease_2010-02.pdf.
83 Pat Roche, "Total Abandoning Joslyn SAGD After Steam Injection Blew Hole In Ground," *New Technology Magazine* (February 26 , 2011); http://www.newtechmagazine.com/issues/story.aspx?aid=1000361019 (accessed 31 April 31, 2011).


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