Troubled Waters, Troubling Trends

Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta

May 2006

REPORT

Mary Griffiths

Amy Taylor • Dan Woynillowicz

the PEMBINA institute

Sustainable Energy Solutions

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1st Edition

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Environment Canada Environnement Canada

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About the Pembina Institute

The Pembina Institute creates sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance. More information about the Pembina Institute is available at http://www.pembina.org or by contacting info@pembina.org

"It is rare indeed to find thinking people in any large producing area of the world putting fresh water down a hole to force out oil."

The Honourable Nick Taylor, P. Geol., retired Canadian Senator and former Member of the Alberta Legislature

Acknowledgements and Disclaimer

Information about various companies and projects is provided in this report. We appreciate the help of many people in providing and checking the data. In certain instances, a specific project or process is used within the report as an illustrative example. This use of such examples does not suggest that these companies, projects or processes are unique in terms of the problems associated with them or the solutions being employed. We recognize the openness of several companies in acknowledging and identifying challenges and their efforts to address them. We hope that our report will encourage all involved in the management and use of water for oil recovery to find ways to reduce their impact on the environment.

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The contents of this report are entirely the responsibility of the Pembina Institute and do not necessarily reflect the views or opinions of those acknowledged above. We have made every effort to ensure the accuracy of the information contained in this report at the time of writing. However, the authors advise that they cannot guarantee that the information provided is complete or accurate and that any person relying on this publication does so at their own risk.

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Foreword

by Dr. David Schindler, Killam Memorial Professor of Ecology, University of Alberta

Here in the province of Alberta, the petroleum industry has been doing its best to disprove the old adage that oil and water do not mix. Water is used lavishly in the extraction and refining of both conventional oil and synthetic crude. There are compelling reasons why this must cease.

Alberta has never had an abundance of water. The province is in the rain shadow of the Rocky Mountains, which causes its southern prairies to be the driest part of southern Canada. Despite semi-arid conditions, European settlers have eked out a living for more than a century. Thanks to a low population of humans and only early stages of industrial development, Albertans have used water as if it were plentiful.

But in the early 21st century, there are troubling signs that the era of abundant water is nearing an end. The climate of the province is changing rapidly, with many areas showing increases in average temperatures of 1 to 4°C since the mid-20th century. As a result, water loss to evaporation is increasing. Glaciers and snowpacks of the Rocky Mountains, which have partially compensated for the low summer rainfalls by supplying water for irrigation and municipal use, are dwindling. The population of the province has increased rapidly, as new immigrants rush to obtain jobs in the rapidly expanding petroleum industry.

Finally, there is now strong evidence that the 20th century was the wettest in several hundred years. In past centuries there were droughts that made the “dirty 30s” look insignificant by comparison. In short, human use, climate warming and the prospect that historic prolonged drought will reoccur make it very likely that Alberta will see extreme water shortages in the years to come. Only extensive conservation measures can prevent disaster.

This report lays out in great detail the excessive use of water by the petroleum industry, which is the result of lax current government water policies. Of particular concern is that much of the water used by the petroleum industry is injected deep underground where it does not return to the surface water cycle, or lies in expansive oil sands tailings ponds, highly contaminated with bitumen residues. This book proposes technological and policy changes by which water use and water pollution by the petroleum industry might be reduced. These proposed changes represent significant steps toward reasonable solutions for one of the province’s major water uses. I hope that equally critical and reasonable proposals for agriculture and municipal use will be forthcoming.

Executive summary

1. The challenge

The increasing demand for water in Alberta threatens the sustainability of the province's surface water and groundwater supplies. Alberta's *Water for Life* strategy sets out a framework for the management of the province's water resources. The Pembina Institute supports this strategy to conserve water in all sectors of the economy.

Since the Institute focuses on sustainable energy solutions, this report specifically examines the use of water for oil recovery and the impacts that the oil industry has on Alberta's water resources. Water is needed for three types of oil recovery: oil sands mining, the in situ recovery of bitumen that is too deep to mine and the enhanced recovery of conventional crude oil.

The demand for water for oil sands mining is enormous. To produce one cubic metre (m^3) of synthetic crude oil (SCO) (upgraded bitumen) in a mining operation requires about 2–4.5 m^3 of water (net figures). Approved oil sands mining operations are currently licensed to divert 359 million m^3 from the Athabasca River,[1] or more than twice the volume of water required to meet the annual municipal needs of the City of Calgary. Less than 10% of this water returns to the river; despite recycling, much ends up in tailings ponds or evaporates from the ponds' surface. The extensive tailings ponds holding wastewater from mining operations can be seen on regional-scale satellite pictures.

Less visible is the water used to produce steam that is injected underground to extract bitumen from in situ operations, and the water that is pumped into oil-bearing reservoirs to enable the enhanced recovery of conventional oil. Only 7% of bitumen can be reached by mining; the rest is obtained by drilling wells into the bitumen (in situ methods). When water is recycled, the volume of water needed to generate steam to recover a unit of bitumen from in situ production is about one-tenth of the volume withdrawn for oil sands mining. However, due to the location of in situ operations, the water is often withdrawn from the ground, rather than from rivers or lakes. This groundwater may be fresh or saline, depending on the depth from which it is withdrawn. It can be difficult to anticipate the long-term cumulative effects of such withdrawals on an aquifer.

Crude bitumen deposits underlie approximately one fifth of the province,[2] and at the current rates production could last more than 400 years.[3] In fact, between 2005 and 2014 production is expected to more than double.[4] This expansion will drain more peatlands, use more surface water and groundwater and create more waste. Yet at current production rates there is already concern

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[1] This includes allocations for the Canadian Natural Resources Horizon project and the Shell Jackpine project, which are currently being licensed.

[2] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, p. 2-4, http://www.eub.gov.ab.ca/bbs/default.htm

[3] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm In 2004 Alberta produced 63 million m^3 of crude bitumen; the remaining established reserves were 27,662 m^3. The ultimate potential recoverable is almost twice the remaining established reserves.

[4] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm

that the demand for water to process and upgrade mined bitumen will negatively impact the Athabasca River, resulting in insufficient water to keep the river healthy at low flow periods during the winter.

2. Water allocation and use

In Alberta in 2004, over 7% of total water allocations (surface water and groundwater) was for the production of oil and gas. This includes the recovery of conventional oil, recovery of oil from bitumen and its processing. The proportion of groundwater allocations is far higher, at 37%.

Water rights in Alberta have been granted on the principle of “first in time, first in right.” All water in the province is regulated under the *Water Act,* which came into force in 1999. Licences issued under the Act are for a fixed term but licences that were issued under earlier legislation were often issued in perpetuity. This includes many licences issued for the enhanced recovery of conventional oil. Apart from the licence fee, there is no charge for water used or diverted under a provincial licence, although the *Water Act* allows water rights to be transferred to a new licencee under certain conditions. An environmental impact assessment (EIA) is usually required for oil sands projects and this may involve not only Alberta Environment and the Alberta Energy and Utilities Board (EUB) but the federal government as well.

Oil sands mining operations divert and use water in many ways. The preparation of the mine site involves draining the overlying muskeg and overburden, as well as depressurizing the basal aquifer to prevent seepage of groundwater into the mine pit area. Transporting the mined bitumen and processing uses large volumes of water, most of which is sent to tailings ponds to be recycled in ore processing. Although some water is recycled in the mining operations, tailing ponds already cover an area in excess of 50 square kilometres. Water is also used to upgrade the bitumen into lighter crude synthetic oil.

The two most common processes for the in situ production of bitumen are cyclical steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). The number of new projects has increased rapidly since the development of SAGD. Many use fresh water, including fresh groundwater, and freshwater use has been growing much faster than expected. Some projects use saline water and almost all projects recycle water. Saline water and recycled water must both be treated before they can be used to generate steam. Some of the waste from the treatment process is injected into deep wells while some is landfilled.

In older conventional oil fields, water may be pumped into the formation to maintain pressure and to recover more oil. Either fresh or saline water can be used for this enhanced oil recovery (EOR). Much of the produced water is recycled, so as the volume of oil produced in a pool declines, less additional outside water is required. The increase in water requirements to expand existing pools or develop EOR in new, small pools is slower than the decline in demand at older EOR sites. Thus, the total volume of water used for conventional EOR in Alberta is at present declining.

The amount of water used for oil recovery is often significantly less than the volume allocated, but the proportion varies between companies and the age or type of project. Table 2-3 provides figures on existing, approved and planned water diversions for oil sands mining operations. Table 2-5 shows the expected average water use for in situ operations for the period 2005-2025, based on company predictions. Figure 2-17 shows water use for conventional EOR.

3. Environmental impacts

To measure the impact of water withdrawals, it is essential to have baseline information on water resources. Knowledge of the extent of fresh groundwater resources in the province is incomplete and research is underway to determine, for example, the extent of buried glacial channels in some northern parts of the province. While the lack of monitoring wells in much of northern Alberta is a special concern, there are also gaps in the monitoring network in central and southern Alberta.

Water supply has been identified as one of the top four challenges for mining operations in Alberta. Most of the water is withdrawn from the Athabasca River and the main concern is negative impacts on the aquatic ecosystem, in particular fish habitat, during the river's winter low flow period. Depressurization of the basal aquifer to prevent flooding in the mine pits can result in changes in the level of other aquifers and surface water bodies, including wetlands that are dependent on groundwater recharge. In one mining project, the basal water aquifer is predicted to be partially recharged from the Athabasca River, further reducing water in the river.

The current practice of storing fluid, fine tailings in ponds presents a major environmental challenge. The risks include the migration of pollutants through the groundwater system and leaks to the surrounding soil and surface water. Should a containment dyke fail, there would be a major ecological disaster due to the residue of bitumen and other substances in the water. Thus, dykes need to be stabilized for decommissioning after operations cease.

Bacteria in the tailings ponds produce methane, a potent greenhouse gas, and flooding of the vegetation that underlies the ponds releases mercury into the water. Napthenic acids, which occur naturally in the bitumen, become concentrated in the tailings ponds making the water toxic to aquatic organisms and mammals; as a result, water cannot be released to the environment. Further development of reclamation options capable of handling the fine tailings from bitumen mining in a manner that is technically, environmentally and economically viable is required.

Potentially irreversible effects are expected in the Muskeg River watershed, and wetlands and peatlands across the entire region will be impacted. There are no known methods to replace peatlands since they take thousands of years to develop, and post-mining conditions, such as salinity, will not be conducive to their re-establishment. End pit lakes (EPLs) will be a permanent feature of the reclaimed landscape, but it is not yet known if they will support a sustainable ecosystem. Changes in the amount of water in the natural ecosystem will affect the distribution of flora and fauna across the region.

The type and magnitude of impacts associated with the in situ recovery of bitumen depend on the recovery process, the volume of water used, the source of the water (surface water or fresh or saline groundwater), the water recycling rate and the local geological conditions. If there are several projects in close proximity, cumulative impacts on groundwater will result. There are concerns about a number of potential and realized environmental impacts associated with the use of water for in situ bitumen recovery operations, including

- the removal of fresh water from the watershed;[5]
- the drawdown of fresh aquifers and changes in groundwater levels;

[5] The authors recognize that some of the water used for other purposes, such as industrial cooling or irrigation, similarly does not return to the watershed. However, as the Pembina Institute focuses on energy issues, these other uses are beyond the scope of this report.

- depressurization of geological formations by the removal of water, resulting in decreased aquifer pressure and increased rates of recharge;
- the removal (“voidage”) of bitumen from production zones, which can result in significant changes in the storage and flow of water in and through these zones when the depleted bitumen reservoirs become groundwater aquifers;
- the availability of saline water;
- waste disposal in deep saline aquifers; and
- landfilling of waste from water treatment processes.

In some locations there is concern about the mobilization of naturally occurring arsenic close to and down gradient from well bores; occasionally the release of production fluids during casing failures or seepage from the well bore has contaminated adjacent fresh water aquifers and required remediation.

The use of fresh water for conventional EOR is also a concern in some agricultural regions of the province, where the demand for water exceeds the supply, especially in drought years.

Some other activities associated with oilfield operations may have impacts if operations are not properly conducted. For example, seismic surveys to locate oil may pose a risk to groundwater if shot holes are not properly filled. Each year the EUB reports leaks from pipelines transporting saline water.

4. Technologies to reduce water use

Water recycling is an important way to reduce the volume of new water required. In some cases, saline water can be used instead of fresh water. However, both recycled and saline water must be treated before they can be used to generate steam for in situ recovery. New water treatment processes are being developed that create less waste, thus reducing the volume of waste that must be landfilled or disposed of in deep wells.

In oil sands mining, new techniques are being developed to improve consolidated tailings (CT), promote the settling of fine solids in tailings ponds and reduce the volume of water required for process cooling. A new process is being piloted to create dry tailings, which not only reduces the use of water but aids the reclamation process.

Solvents, such as VAPEX, can be used to reduce or eliminate the need for water during in situ recovery of bitumen. New work on the in situ combustion or gasification of bitumen will, if successful, enable oil to be recovered from bitumen with the use of very little water. Toe-to-Heel Air Injection (THAI™) only requires water to steam the formation until it reaches combustion temperature, usually about three months. During commercial production the process will actually produce water with the oil.

In addition to developing new technologies to reduce impacts on water, work is needed to assess the capacity of shallow saline aquifers to supply water and to determine the potential impact of incomplete voidage replacement on surface water and shallow aquifers. The impact of disposing large volumes of water produced from oil sands operations into intermediate depth aquifers in northeast Alberta and the potential for its migration to shallower zones should also be addressed. While further water recycling may be possible in some conventional EOR operations, the use of carbon dioxide (CO_2) and other gases is the most likely method to enhance conventional oil recovery while reducing the demand for water.

5. Policies to reduce water use

Effective management requires a comprehensive policy framework that recognizes that water is a public resource, ensures that decisions on water use are based on high quality data and scientific knowledge, prevents wasteful use of the resource, weighs the relative worth of different water uses and provides adequate protection for ecosystems. Policy must be adaptable to allow for changing objectives and priorities over time.[6] The current policy framework in Alberta related to water use by the oil sector is inadequate. With respect to water use by the oil sector in Alberta

- there is not sufficient high quality data and information on which to base policy decisions.
- the policy framework does not ensure that the full costs of water use are borne by the oil sector and therefore it does not provide a financial incentive to reduce water consumption.
- the policy framework does not drive innovation or encourage/require the use of the best available technologies and processes when it comes to water conservation.
- the policy framework is not adaptable and therefore cannot adequately adjust to changing climatic, geographic, and/or socio-economic conditions.

Due to concerns about the use of water by the oil industry, the provincial government set up the Advisory Committee on Water Use Practice and Policy to examine the use of water for conventional EOR and for the in situ recovery of bitumen. The *Water Conservation and Allocation Policy for Oilfield Injection*, based on the committee's recommendations, was introduced in early 2006. This policy and the associated guideline will help reduce the use of water, especially in water-short areas, but both must be strictly implemented. It is unknown whether companies that hold licences in perpetuity will voluntarily return allocations of water that they do not use. Moreover, the Advisory Committee did not examine the use of water for oil sands mining and processing, which is extremely large in northern Alberta.

In addition to implementing the recommendations of the Advisory Committee, we recommend that the government establish water use targets for the oil sector,[7] implement user fees on fresh water consumption by the oil sector and further evaluate other policy options if the reduction targets are not met.

The targets should be increasingly stringent over time to drive innovation and push companies to continually reduce water use. The volume-based charge should provide an incentive for companies to use saline water instead of fresh, making it more economical.

The revenue from user fees should be placed in a dedicated "water management" fund and used to finance administrative costs and research and development, and respond to data and information gaps, especially those related to groundwater resources.

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[6] Teerink, John R. and Masarhiro Nakashima. 1993. *Water Allocation, Rights, and Pricing: Examples from Japan and the United States.* World Bank Technical Paper Number 198. Washington, DC.

[7] Already in Alberta targets are to be set as part of the *Water for Life* strategy. The Alberta Water Council is currently working on this. If the targets established as part of the *Water for Life* strategy are sufficiently stringent, they could drive innovation and technology development.

6. The way forward

A vision of wise water management shows the oil industry avoiding the use of fresh groundwater, minimizing the use of surface water and maximizing the use of saline water as much as possible except where the need to treat saline water poses additional concerns over waste generation and management. Where water is required, saline water, which is a produced as a by-product of adjacent operations (e.g., produced water associated with oil, gas or coalbed methane recovery), is generally used to replace water from other sources. The recycling of water is optimized. When planning a new project, a company evaluates the life-cycle impact of different technologies and implements those that minimize water use and other environmental impacts.

A range of measures is needed to attain this vision of wise water management. We recommend that the government begin by establishing water use targets and implementing fresh water user fees, and then consider other policies if water use targets are not achieved. Since knowledge is the basis for sound management, more information on water quality and quantity is needed, and the baseline study of Alberta's groundwater resources must be completed. It is necessary to work out a water balance for each river basin to ensure that allocations of surface water and groundwater do not exceed the sustainable supply. Regular public reports on watershed management will enable the Alberta Water Council and Albertans to ascertain that progress in being made.

In oil sands mining areas ways must be found to manage current and ongoing cumulative effects before further developments are approved. Every EIA should provide a detailed review of cumulative impacts and the federal government should take a more active role in setting terms of reference and reviewing all EIAs. Decisions about additional water allocations should be deferred until there is sufficient knowledge to ensure sustainable management of the resources. Water licences should continue to include provisions for a staged reduction in use for oil sands mining. Clear expectations must be set for the management of tailings and the reclamation of tailings ponds.

Some processes to improve water management have already started. The wetlands policy, being developed by the Alberta Water Council, must be completed as soon as possible, as oil sands development continues to exert significant pressure on northern wetlands. It is hoped that the *Water Conservation and Allocation Policy for Oilfield Injection* will be effective in reducing the use of fresh water for both in situ and conventional oil recovery. A company requiring water for conventional EOR or in situ production of bitumen will be required to seek alternatives before applying for a licence to use fresh water. This search will be more stringent in water-short areas and for large-scale projects, but Alberta Environment will still need to ensure that the oil sector is on the cutting edge in its use of technology to reduce water use and impacts.

The government must make full use of its powers under the *Water Act* to regain water to meet instream flow needs (IFN) whenever there is a transfer of water rights.

The responsible government departments and agencies must be given sufficient resources to better manage the province's water resources. Additional resources are needed particularly with the rapid growth in oil sands development. The publication of an annual water report should help ensure accountability and identify where more effort and resources are needed.

Technology can play a role in reducing water use and impacts, and several areas merit the attention of government, industry and research institutions.

There is an urgent need for action. As the population and level of economic activity in Alberta grows, so does the demand for water across the province. Climate change will likely increase the variability of precipitation and reduce flows in rivers that are fed by mountain glaciers. An increasingly scarce resource will need to be shared among more users. In some areas it will become necessary to determine which is more important: water or oil.

Summary table: Comparison of oil production processes

	Oil sands		Conventional oil
	Mining	**In situ recovery**	**Enhanced oil recovery**
Type of oil	Bitumen	Bitumen	Oil, heavy oil
Depth	Less than 75 metres	More than 75 metres	Approximately 500–4,000 metres
Location	Northeast Alberta, Athabasca region around Ft. McMurray and Athabasca River	Cold Lake, Athabasca region, Peace River area	Over much of western, central and southern Alberta (see Figure 2.1)
Process	Drain muskeg and divert rivers and streams, remove overburden, depressurize basal aquifer and drain mine; remove bitumen; extract bitumen using large volumes of water to separate oil; transport wastewater with residual bitumen to tailings ponds; upgrade bitumen using steam to remove impurities such as sulphur, nitrogen and carbon to produce synthetic crude oil	The two most common processes are cyclical steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) Both are thermal processes that inject steam into the bitumen to soften it, then separate it from the sand grains so that it can be pumped to the surface	Inject water into the formation to maintain reservoir pressure and enable the extraction of additional oil
Type of water used	Surface water and recycled water from tailings ponds	Some surface water, but more operations use fresh and saline groundwater	Fresh and saline groundwater

Impacts and potential Impacts	Removal of large volumes of water from the Athabasca River; potential impact on fish habitat Draining and clearance of muskeg prior to removal of overburden for mining causes drawdown of fresh groundwater and drying of adjacent wetlands Waste water and residual from the extraction process collected in enormous tailings ponds, where water is contaminated with napthenic acids, mercury, and other toxics No single reclamation option capable of handling the projected volumes of fine tails in environmentally acceptable and economic manner Loss of bog and fen peatlands in the reclaimed landscape Uncertainty about the viability of EPLs as a sustainable ecosystem, after closure of mine operations	Drawdown of fresh water aquifers to provide water for steam injection Infiltration of fresh water into voids created by bitumen removal or drawdown of shallow saline aquifers Impacts on water quality close to well bore, due to heat or leaks Potential leakage of leachate from landfills in which wastes for water treatment are disposed	Use of surface water and freshwater aquifers a concern for landowners in water-short areas Potential impact from seismic surveys on water wells Leaks from pipelines transporting saline water for oil recovery or deep well injection (or surplus produced water)
Alternatives to fresh water	Enhanced water recycling from tailings ponds	Saline water Solvents instead of water in SAGD process Toe-to-Heel Air Injection, a heat process with water only used for start-up	Saline water Carbon dioxide or other gas

1. The challenge

1.1 Introduction

Water in western Canada is under pressure, as is clearly described in a recent report by a Canadian Senate committee.[8] In Alberta, a combination of dramatic economic growth, increased human population, extended periods of drought conditions, and questions about the long-term impacts of climatic change has led to serious concerns about the sustainability of the province's surface water and groundwater resources. As the government of Alberta has pointed out, these pressures present a risk to the well-being of Albertans, our economy and our aquatic ecosystems.[9]

Concern about the availability of water led the Alberta government to introduce its *Water for Life* strategy in 2003. This strategy provides a framework for the sustainable management of the province's water resources. During the public consultation for the strategy, the consumption of fresh water by the oil industry was identified as a major concern, as were uses by other industries, cities and agriculture.

The demand for water by the oil industry is growing. Between 2001[10] and 2004 allocations of water for the oil industry increased, both as a proportion of the total water allocated in the province and in absolute amounts. Large volumes of water are used to extract oil from bitumen from the oil sands[11] and the demand for water in northern Alberta will grow rapidly with the planned expansion of the oil sands. The Alberta Energy and Utilities Board (EUB) expects the production of bitumen to more than double between 2004 and 2014 (increasing from 173,000 cubic metres per day (m^3/d) in 2004 to 408,000 m^3/d by 2014).[12] Some energy analysts are projecting that oil sands production could reach anywhere from 500,000 m^3 to 1,600,000 m^3 per day by 2015 and the late 2040s respectively.[13,14] Although production of conventional crude oil has reached its peak and the volume of water used to obtain more oil from conventional oil wells may continue to decline on a provincial basis, there is considerable potential for further waterflooding of newly discovered conventional oil pools or existing pools that were previously below economic limits for enhanced recovery.

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[8] The Honourable Tommy Banks and the Honourable Ethel Cochrane. 2005. *Water in the West: Under Pressure.* Fourth Interim Report of the Standing Senate Committee on Energy, the Environment and Natural Resources.

[9] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability*, http://www.waterforlife.gov.ab.ca/

[10] The year 2001 was the most recent year included in a report on the use of water for oilfield injection , i.e., water used for the in situ recovery of bitumen and conventional enhanced oil recovery. Geowa Information Technologies, Ltd. 2003. *Water Use for Injection Purposes in Alberta.* Prepared for Alberta Environment and available online at http://www.waterforlife.gov.ab.ca/docs/geowa_report.pdf At the time of writing, Alberta Environment is updating this information. Water allocations for oil sands mining also increased over this period.

[11] Oil sands are sometimes referred to as tar sands.

[12] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-16 to 2-17. Figures derived by summing production from mining and in situ crude bitumen.

[13] United States Energy Information Administration. 2004. *Issue in Focus: Natural Gas Consumption in Canadian Oil Sands Production.*

[14] First Energy Capital Corp. July 7, 2005. *Multicyclic Hubbert Curve Theory and Canada's Future Oil Outlook: Could Oil Sands Production Reach 11 Million Barrels per Day?*

These trends raise a number of questions: Will water be a constraint on oil sands development? Will oil sands development jeopardize the sustainability of water resources in northern Alberta? In areas of the province where water resources have already been over-allocated, can the use of water for conventional oil recovery be reduced?

To address these questions, this report reviews the amount of water used by the oil industry and describes the associated impacts on the province's water resources. It covers the impacts of mining and upgrading bitumen from the oil sands, the use of steam for the recovery of oil from bitumen deposits that are too deep to mine, and the injection of water to obtain more oil from conventional wells, which produce lighter oil. Some of these activities can cause changes in natural river flows, which can have implications for aquatic ecosystems if not managed properly through an effective regulatory process. In addition, use of groundwater may lower water levels. Should this happen, it could affect not only the level and quality of water in shallow aquifers,[15] but also the recharge of wetlands and surface water bodies. Additional potential environmental impacts are associated with the treatment of water for use or recycling, and the storage and management of contaminated water.

As well as identifying the negative environmental impacts associated with water use by the oil sector, in this report we present and discuss technology and policy options for reducing water demand. We focus our attention on reducing the use of fresh water, given its integral role in ecosystem function and diversity and because, with treatment, it may be useful for human and agricultural purposes. Throughout this report the term "fresh" applies to surface water and to non-saline groundwater.[16] Alberta Environment defines saline water as water that contains more than 4000 milligrams per litre of total dissolved solids (mg/l TDS).[17] This level was set to include all groundwater that is expected to be potentially useable by the public in the future with reasonable levels of treatment. In fact, fresh or "non-saline" groundwater reflects a range of quality, from water that is suitable for drinking (once treated to remove bacteria, etc.)[18] to water useable for certain livestock watering but unacceptable for irrigation.[19] Some stakeholders believe a higher cutoff is desirable as more complex treatment technology is possible in extreme water shortage situations.

1.2 Balancing water supply and demand

Water is the basis for all forms of life and is an essential resource for ecological sustainability, economic activity and human well-being. We need water for everything from urban growth and irrigation to natural resource extraction and manufacturing. These needs are running up against the reality of a finite and, in some watersheds, shrinking water supply. Hence, if we want to

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[15] See the Glossary in this report for a definition of "aquifer" and other terms.

[16] Non-saline water, as defined, may not be suitable for drinking but might be used for watering livestock or for irrigation (suitability for irrigation depending on the level of salts in the water, the crop grown and the sodium adsorption ratio of the soil). Some companies refer to saline water as "brackish" water, but there is no official definition of brackish water, and occasionally the term has been used to refer to non-saline water that has more dissolved solids than acceptable in drinking water.

[17] Non-saline groundwater is water that is not saline. Saline groundwater is defined in the *Water (Ministerial) Regulation, section 1(1(z))* as water containing more than 4,000 milligrams of TDS per litre (TDS/l), http://www.qp. gov.ab.ca/index.cfm The EUB has indicated that most of the shallow groundwater used for oilfield injection is not suitable for drinking. Alberta Energy Utilities Board, personal communication, February 2006.

[18] Drinking water should not have more than 500 milligrams TDS/l. Health Canada. 2006. *Guidelines for Canadian Drinking Water Quality – Summary Table,* http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html

[19] The actual salinity of water that can be used for irrigation depends on the crop and sodium adsorption ratio of the soil.

sustain economic growth, finding ways to increase water conservation is both logical and necessary.

Between 2000 and 2004, the population of Alberta grew by 7% to over 3.2 million.[20] Over the same period of time, the provincial economy grew even faster. Between 2000 and 2004, Alberta's Gross Domestic Product increased by 29% from nearly $145 billion in 2000 to $187 billion in 2004.[21] Because the supply of water is finite and even diminishing in some parts of the province, we now have the same amount or less water available to support more people and a larger economy than in the past. The limit of available water has already been reached in a number of watersheds, and is being approached in others.[22] The situation varies across the province; in the South Saskatchewan River Basin, for example, 70% of the natural stream flow has been allocated.[23] While more than two-thirds of the allocation is for irrigation, any use that removes water from the basin is a concern. Water that is used for conventional EOR or for in situ recovery of bitumen stays in the geological formation and does not return to the water basin.[24]

Management of groundwater is also a concern. Changes in groundwater levels have not been monitored and assessed in any detail across the province (see section 3.1.2). In some areas, such as the Athabasca Oil Sands, there is extensive monitoring by the oil industry in the vicinity of the oil sands mines, but this monitoring, required by government, does not look at the wider regional impacts. Groundwater resources are insufficient to meet demand in some areas and groundwater levels have declined in drought years. For example, in 2002 the Alberta government passed legislation to allow an inter-basin transfer of water that involved the construction of a pipeline to take water from the Red Deer River. The water is required to supply the communities of Blackfalds, Lacombe and Ponoka and several First Nations bands, since they were experiencing problems with groundwater quantity and quality.[25]

Considerable changes have been seen in river flows in Alberta during the period for which there are reliable records.[26] At the end of the 20th century the summer flow in the province's major rivers had declined to approximately 60% of the flow at the beginning of the century.[27] While this is partly due to increasing demand for water and human-made changes to watersheds, such as dams, changes in climate are probably also a major factor. Temperatures have been

[20] Statistics Canada.2005. *Population by sex and age group, by provinces and territories,* CANSIM Table 051-0001, http://www40.statcan.ca/l01/cst01/demo31a.htm

[21] Statistics Canada. 2005.*Gross domestic product, expenditure-based, by provinces and territories,* CANSIM Table 384-0002, http://www40.statcan.ca/l01/cst01/econ15.htm

[22] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability*, http://www.waterforlife.gov.ab.ca/

[23] Alberta Environment. Undated Chart. *Water Allocations in Alberta by Major River Basin as Percentage of Average Natural Streamflow Volumes (Surface plus Groundwater Allocations, as of 2001).*

[24] Although the water is withdrawn from the water basin, when a cubic metre of oil is burned it will return a cubic metre of water to the atmosphere. Bruce Peachey in response to a question at the *2005 Water Efficiency and Innovation Forum for the Oil Patch.* Petroleum Technology Alliance of Canada. Calgary, Alberta. June 23, 2005.

[25] North Red Deer Water Authorization Act, http://www.qp. gov.ab.ca/catalogue/catalog_results.cfm The *Water Act* requires an Act of the Legislature to authorize inter-basin transfer, even when the piped water is treated, as in this case. The pipeline will transfer water from the South Saskatchewan River Basin to the North Saskatchewan River Basin.

[26] Schindler, David W. and William F. Donahue. 2006. An impending water crisis in Canada's western prairie provinces. *Proceedings of the National Academy of Sciences*, April 10, 2006.10.1073/pnas.0601568103. The greatest decline in summer flows was in the southern part of Alberta. In some cases the decline is due to dams and diversions, as well as to changes in the natural flows due to increased warming effects on evaporation, evapotranspiration and winter snowpack. Abstract available at http://www.pnas.org/cgi/content/abstract/0601568103v1

[27] William Donahue, Freshwater Research Ltd., personal communication, June 2004. In 1999 the flow in the Slave River was 67% of the initial flow, while figures for the Peace and Oldman Rivers were 62% and 59% respectively.

increasing, rising an average of 2.3°C in Edmonton between 1937 and 2000 and by almost one degree in Calgary over the same time period.[28] It seems that at least in northeast Alberta, changes in catchment yield are probably most closely related to a decline in the spring snowpack.[29] It is predicted that temperatures will continue to increase as a result of climate change and that, due to the effects of increased evaporation and the melting of glaciers that help supply the headwaters of some of the major rivers in the province, water supply will in turn diminish.[30] These changes will impact not only surface water but also the recharge of aquifers.[31]

In addition to pressures in terms of increased demand, changes in flow and deteriorating quality, there is the added pressure of legal obligations embedded in downstream water agreements with Saskatchewan, Manitoba, the Northwest Territories and Montana.[32] In the end, managing the demands on Alberta's finite water supply so that there is enough to support both the ecological integrity of watersheds and economic growth is vital to the future well-being and prosperity of Albertans and all other Canadians alike.

1.3 Alberta's *Water for Life* strategy

The Government of Alberta's *Water for Life* strategy was designed to meet the challenge posed by the increasing demand for water in the province. Through this strategy, the government committed to the wise management of Alberta's water quantity and quality for the benefit of Albertans now and in the future.[33] There are three key goals associated with the *Water for Life* strategy:

- Albertans will be assured their drinking water is safe.
- Albertans will be assured that the province's aquatic ecosystems are maintained and protected.
- Albertans will be assured that water is managed effectively to support sustainable economic development.

Important principles that underlie the strategy are that

- Albertans must become leaders in using water more effectively and efficiently, and will use and reuse water wisely and responsibly.
- Alberta's water resources must be managed within the capacity of individual watersheds.

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[28] Environment Canada annual average figures, provided by William Donahue of Freshwater Research Ltd.

[29] These are preliminary findings from research being undertaken by William Donahue of Freshwater Research Ltd. Comparison of historic data and models seems to indicate that much of the decline in summer river flow in northeast Alberta is due to the effect of climate change on catchment yield. Most of the declines are driven by decreases in water flow in May, with less of a decline in June, July and August, in that order. This work is still underway, so results are not conclusive. Personal communication, February 2006.

[30] Schindler, David. 2004. *Climate and Water Issues in the Athabasca River Basin.* Talk given at Athabasca University, Lunch 'n' Learn Forum, October 22. An edited version of the talk and slides are available online at http://aurora.icaap. org/2005Interviews/Schindler/dschindler1.html See also, David Schindler. 2002. "The Effects of Climate Warming and Cumulative Human Activity on Canada's Fresh Water in the 21st Century," in *Water and the Future of Life on Earth*, P. and L. Wood (Eds.). Proceedings of the workshop and think tank, May 22 –24, 2002, presented by Continuing Studies in Science, Simon Fraser University and Liu Centre for the Study of Global Issues, University of British Columbia.

[31] Rivera, Alfonso. 2005. How well do we understand groundwater in Canada? A science case study. In Linda Nowlan. 2005. *Buried Treasure: Groundwater Permitting and Pricing in Canada,* p. 6. Report prepared for the Walter and Duncan Gordon Foundation, http://www.gordonfn.org/FW-pubs&links.cfm

[32] Wilkie, Karen. 2005. *Balancing Act: Water Conservation and Economic Growth*. Canada West Foundation, http://www.cwf.ca/

[33] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability*, http://www.waterforlife.gov.ab.ca/

- Groundwater and surface water quality must be preserved in pursuing economic and community development.

The strategy sets a target of a 30% improvement in the efficiency and productivity of water between 2005 and 2015 and notes that economic measures may play a role in achieving that efficiency target. Specifically, Alberta's *Water for Life* strategy refers to the following key actions:

- Determine and report on the true value of water in relation to the provincial economy.
- Complete an evaluation and make recommendations on the merit of economic instruments to meet water conservation and productivity objectives.
- Implement economic instruments as necessary to meet water conservation and productivity objectives.

Recognizing the need to address water issues related to oil extraction in the province, the government established the *Advisory Committee on Water Use Practice and Policy* even before the *Water for Life* strategy was announced. This multistakeholder committee was appointed to review ways to improve the management of water related to underground injection, which is primarily used for enhanced recovery of oil or the thermal recovery of bitumen.[34] The committee's recommendations identified ways to reduce or eliminate on a case-by-case basis the use of fresh water for underground injection,[35] and formed the foundation for Alberta Environment's *Water Conservation and Allocation Policy for Oilfield Injection,* and the associated guideline, which came into force in April 2006.[36] The government has not yet taken any complementary measures to curtail the use of water for oil sands mining and provide clarity on future licence allocations.

1.4 Oil's thirst for water

The oil industry relies on various techniques and technologies for oil extraction in different parts of the province. The use and demand for water for conventional oil recovery is different from that for in situ[37] production and different again for oil sands mining. Here are a few facts that show the industry's thirst for water:

1. In 2004, 7.3% of total water allocations in Alberta (surface water and fresh groundwater) were for conventional EOR and the production of oil from bitumen, by mining and in situ methods, as well as for its processing.[38] The proportion was far higher for groundwater

[34] Alberta Environment. 2003. *Advisory Committee on Water Use Practice and Policy: Terms of Reference,* http://www.waterforlife.gov.ab.ca/docs/advisoryTOR.pdf The Minister of Environment appointed the committee a few months before the *Water for Life* strategy was announced. The three co-chairs were David Trew, Alberta Environment; David Pryce, Canadian Association of Petroleum Producers; and Mary Griffiths, Pembina Institute. The working documents and final recommendations of the committee are online at http://www.waterforlife.gov.ab.ca/html/removed.html Apart from the recovery of oil, water is sometimes injected to create new salt caverns for the storage of gas or waste products.

[35] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report.* The working documents and final recommendations of the committee are online at http://www.waterforlife.gov.ab.ca/html/removed.html

[36] Alberta Environment. 2006. *Water Conservation and Allocation Policy for Oilfield Injection,* http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf and *Water Conservation and Allocation Guideline for Oilfield Injection,* http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[37] *In situ* is Latin for 'in place'. See section 2.3.2 for a description of the in situ recovery processes.

[38] Alberta Environment. Figures for 2001 are from the *Advisory Committee on Water Use Practice and Policy: Final Report,* p. 12 and 13. Data for 2004 supplied by Alberta Environment.

alone; in 2004 over 37% of all groundwater allocations in Alberta were for oil recovery and processing.

2. It requires 2 to 4.5 m^3 water to produce 1 m^3 of synthetic crude oil (SCO) from bitumen obtained through mining operations (net figures).[39] In comparison, the in situ recovery of oil from bitumen using steam requires less water per cubic metre of bitumen. Where companies recycle the water, the net requirement for in situ recovery is usually less than 0.5 m^3 and may be less than 0.2 m^3 for 1 m^3 of bitumen.[40] However, water for in situ operations is often taken from groundwater. Since more than four-fifths of the total bitumen reserves in Alberta are accessible only by in situ methods, [41] the demand for water for in situ production could be as great as or greater than that for oil sands mining, unless new processes are adopted.
3. In 2004 Alberta produced 63 million m^3 of crude bitumen and 35 million m^3 of conventional oil.[42] Almost two-thirds of the bitumen production came from mining operations and the rest from in situ operations. Thus the total volume of water required for bitumen recovery is very large. For example, approved oil sands mining companies are licensed to divert 359 million m^3/year from the Athabasca River.[43] This is more than twice as much water as is used by the City of Calgary in a year.[44]
4. As the production of bitumen increases, so will the demand for water. As noted earlier, the EUB expects the production of bitumen from oil sands to more than double in the decade 2004–2014, which could see a comparable increase in the demand for water in northeast Alberta. Many existing allocations are larger than the volume of water currently used, so water use may increase without the allocation being adjusted. However, further allocations will be needed for new projects.
5. The growth of bitumen production is expected to continue for a long time. Extensive crude bitumen deposits underlie approximately one-fifth of the province,[45] but so far only

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[39] Alberta Energy Utilities Board, personal communication, February 8, 2006. In 2004, average water use was 2.6 m^3 per cubic metre of bitumen recovered through mining operations; the overall average was just over 4.0 m^3 water per cubic metre of SCO. See section 2.3.1 for more details on these figures.

[40] These figures do not include upgrading.

[41] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-2 and 2-3. As much as 93% of the initial volume of bitumen in place in Alberta can only be recovered using in situ recovery methods. However, the recovery rate is higher with mining than with in situ production, so it is estimated that in situ reserves are 82% of total bitumen reserves. The total remaining established reserves amount to 27,662 million m^3.

[42] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm The EUB normally reports oil volumes in cubic metres. In this report we follow the EUB practice of using metric measures. One cubic metre of oil is equivalent to 6.2929 barrels of oil. Thus in 2004 Alberta produced 35 million m^3 of conventional oil (220 million barrels) and 63 million m^3 of crude bitumen (399 million barrels) [40.9 million m^3 (257 million barrels) of crude bitumen from the mineable area and 22.5 million m^3 (141 million barrels) from the in situ area].

[43] This includes allocations for the Canadian Natural Resources Horizon project and the Shell Jackpine project, which are currently being licensed.

[44] For example, in 2003 the City of Calgary's population was 922,315 and its municipal water requirement was approximately 174 million m^3 per year. Water use data: Sustainable Calgary. 2005. *2004 State of Our City Report*, p.48, http://www.sustainablecalgary.ca/documents/SOOC2004.pdf Population data: http://content.calgary.ca/CCA/City+Hall/Business+Units/Community+Strategies/Social+Data/Research+Services/Population+Size.htm

[45] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-4. http://www.eub.gov.ab.ca/bbs/default.htm

2.6% of the initial established crude bitumen reserves have been produced.[46] If production were to continue at the same rate as in 2004, the remaining established reserves would last for more than 400 years.[47] To give a further idea of the scale of operations; it is anticipated that, in 2005, Alberta's oil sands production may account for one-half of Canada's total crude output and 10% of North American production.[48] The province has over 27 billion m^3 of bitumen reserves that can be processed with current technology, which makes it second only to Saudi Arabia in proven oil reserves in the world.[49]

6. By 2014, as the production of conventional oil continues to decline, the EUB expects 83% of total crude oil supply to come from bitumen (compared with 57% in 2004).[50] The increasing demand for water for bitumen production more than offsets the slight decline in water requirements for conventional oil recovery.
7. The demand for fresh water for the enhanced recovery of conventional oil is significant and the industry used over 22 million m^3 in 2004.[51] The overall volume of water use has been declining, but is a concern in agricultural areas, especially in drought years.
8. The impact of the oil industry on water is recognized as a challenge by industry itself. EnergyINet[52] has identified one of the six innovation challenges for all industry as water management. More specifically, EnergyINet has recognized the need to "[d]evelop technology to reduce use of fresh water by the energy industry and implement cost-effective water re-use and recycle systems."[53] In a web-based survey, the use of fresh water was identified as the second largest environmental challenge facing the oil and gas sector, after greenhouse gas and associated emissions. Some respondents selected wastewater treatment/handling of produced water as the most important, while a few thought that impacts on groundwater were the biggest challenge.[54]

[46] Established reserves are those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical or similar information with reasonable certainty. Definition from Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. A-2, http://www.eub.gov.ab.ca/bbs/default.htm

[47] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm In 2004 Alberta produced 63 million m^3 of crude bitumen and the remaining established reserves were 27,662 m^3. The ultimate potential recoverable is almost twice the remaining established reserves.

[48] Alberta Energy. Oil sands website at http://www.energy.gov.ab.ca/89.asp

[49] Isaacs, Eddy and Duke du Plessis. 2005. *Energy Development and Future Outlook.* Alberta Energy Research Institute (AERI). Presentation for the Standing Senate Committee on Energy, the Environment and Natural Resources, http://www.aeri.ab.ca/sec/new_res/docs/Isaacs_du_Plessis_Submission_to_Senate_Committee_050307.pdf For those wishing to make international comparisons, 27 billion m^3 is equivalent to approximately 174 billion barrels.

[50] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 3. http://www.eub.gov.ab.ca/bbs/default.htm

[51] Figure from Alberta Energy and Utilities Board. Cheryl Adolf, personal communication, September 8, 2005. See also Figure 2.17, below.

[52] EnergyINet Inc. is a Canadian not-for-profit network that brings industry, researchers and governments together to help develop environmentally responsible hydrocarbon and renewable energy technologies, http://www.energyinet.com/

[53] EnergyINet. 2005. *Unlocking Tomorrow's Energy*, p. 21, http://www.energyinet.com

[54] Petroleum Technology Alliance Canada. 2005. *Barriers to Deployment of Environmental Technologies*, http://www.ptac.org/eet/dl/eetreport0401.pdf In the web-based survey, volunteer respondents were asked to rank a number of issues to identify what they considered as the biggest environmental challenge. Nine respondents selected use of fresh water, 13 identified greenhouse gases and related emissions, five respondents identified wastewater treatment/handling of produced water and three identified the impact on groundwater. There was a total of 80 responses.

The Pembina Institute first identified the environmental concerns associated with the use of water by the oil industry in its 2003 report *Oil and Troubled Waters.*[55] This current report updates and expands on the former one. Although several other public policy reports have drawn attention to the need for water conservation, none has focused on the oil industry.[56] There is no readily accessible, comprehensive overview of the current use of water by the oil industry on a regional basis, with the exception of a 2005 report prepared for the Cumulative Environmental Management Association (CEMA) that summarized current and projected water use demands by oil sands mining operations.[57]A report providing data on water use for oilfield injection in the major river basins was completed for Alberta Environment using data for 2001,[58] but there was no evaluation of environmental issues. Further, it did not address the water used for oil sands mining and upgrading. The current report brings together information from various government departments, regional reports and individual companies, and examines the issues as well as the data.

The *Alberta Water Council* and various water basin councils will be examining ways in which the management and conservation of water in the province could be improved. We hope that this report will help those engaged in water management to better appreciate the issues and possible solutions.

1.5 Cumulative impacts of the oil industry on water

The cumulative environmental impacts of a large number of oil sands developments in northern Alberta will be significant. Indeed, if current development expands at the predicted rate, the impacts will be staggering. While they will be most visible in areas of oil sands mining, the cumulative impact of a large number of in situ projects will also be very large. The effects on groundwater may not be immediately apparent, but good regulation, strong baseline information and monitoring are needed to ensure that there are no long-term impacts on fresh water aquifers.

This report focuses on water use, but it is important to note that water should not be considered in isolation. For example, while it is desirable to minimize the use of fresh water, the use of alternatives may create undesirable environmental impacts. If, for instance, saline water is used instead of fresh water, the process to treat the saline water will use energy and create wastes; greenhouse gas emissions will increase and the wastes will have to be disposed of, either in deep wells or in landfills. This in turn, may harm the environment (see Chapter 3 for further discussion). Where alternative saline water sources are identified at considerable distances from EOR candidates, pipelines needed to transport the large volumes of water may create other environmental and landowner concerns.

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[55] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources*, Pembina Institute, http://www.pembina.org/publications_item.asp?id=154

[56] See, for example, various initiatives in Alberta funded wholly or in part by the Walter and Duncan Gordon Foundation. *Setting the Agenda: A Parkland Institute Symposium on the Politics of Water in Alberta*, held June 18–19, 2004 at the University of Calgary. Karen Wilkie. 2005. *Balancing Act: Water Conservation and Economic Growth.* Canada West Foundation, http://www.cwf.ca/ The Canadian Institute of Resources Law at the University of Calgary is designing a water management framework to indicate how existing water management tools can be integrated with Alberta's *Water for Life* strategy. http://www.gordonfn.org/water-UH.cfm?id=71 Also, Linda Nowlan. 2005. *Buried Treasure: Groundwater Permitting and Pricing in Canada.* Walter and Duncan Gordon Foundation. http://www.gordonfn.org/FW-pubs&links.cfm

[57] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group.

[58] Geowa Information Technologies, Ltd. 2003. *Water Use for Injection Purposes in Alberta.* Prepared for Alberta Environment, http://www.waterforlife.gov.ab.ca/docs/geowa_report.pdf

The trade-off between various environmental impacts should be part of every decision about the most suitable water source, treatment process and technology in any individual project. The best option, that is, the one with the minimum net environmental impact, will vary depending on location. This is recognized in the *Water Conservation and Allocation Guideline for Oilfield Injection*.[59] It identifies three tiers, wherein the extent of the search for alternatives to fresh water should depend on the availability of water, the scale of a project, and anticipated impacts.

Thus, while reducing the use of fresh water is desirable, it is not the sole goal. In water-short areas the need to reduce the use of fresh water will be paramount. Yet, a project that is close to a large source of surface water may be able to use fresh water without any significant negative impacts. When groundwater is used, impacts may be less obvious than when surface water is used, so careful monitoring will be needed. It is important to consider not only the short-term impacts, but also those that may become evident only after many years. This applies not only to the use of groundwater, but also to the removal of large volumes of water and oil from shallow geological formations. It also applies to the disposal of wastes, such as the leaching from a landfill that contains wastes from water treatment processes.

1.6 Other impacts on water resources

This report is about the use of water by the oil industry in Alberta, but other energy and industrial developments, domestic uses and agriculture also require or produce water, which may impact the volume of water available for use within a water basin. While water used for hydroelectric generation continues its flow downstream, some water used for cooling purposes may evaporate and not flow back into the surface water body from which it was taken. Water basin councils that have large coal-fired power plants in their area will need to examine this use of water when evaluating the potential for water conservation.

The development of coalbed methane (CBM) may have impacts on water, since some of the water in coal seams must be removed to lower the pressure in the formation and allow the methane gas to flow to the surface.[60] Where the coal seams are deep and contain saline water, the water may provide a new source of injection water for nearby EOR projects. Where coal seams are shallow, they may contain fresh water. The Multi-stakeholder Advisory Committee on Coalbed Methane/Natural Gas in Coal recognized the importance of protecting fresh water aquifers and makes some recommendations relating to the removal of fresh water from coal seams.[61]

An increasing number of very shallow gas wells completed in sands are being developed, which may produce fresh water together with the gas. The diversion of this water should require a permit under the *Water Act*, but at the time of writing there is no requirement for operators to obtain permission from Alberta Environment before diverting fresh (non-saline) water from shallow gas wells. Alberta Environment plans to address this by introducing a Code of Practice

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[59] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection,* http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[60] The Pembina Institute wrote a preliminary report on CBM in 2003. See *Unconventional Gas: The Environmental Challenges of Coalbed Methane Development in Alberta*, http://www.pembina.org/publications_item.asp?id=157 The issue of water and CBM is being addressed by the Multi-Stakeholder Advisory Committee on Coalbed Methane/Natural Gas in Coal. The committee's preliminary findings are on Alberta Energy's *Natural Gas in Coal/Coalbed Methane* website at http://www.energy.gov.ab.ca/245.asp

[61] Multi-Stakeholder Advisory Committee on Coalbed Methane/Natural Gas in Coal. The committee's preliminary findings are on Alberta Energy's *Natural Gas in Coal/Coalbed Methane* website at http://www.energy.gov.ab.ca/245.asp

for diversion of small quantities of water that will apply to both shallow gas wells and CBM wells, which means that applications would not be needed for diversion of small volumes.[62]

All produced water from oil and gas wells including CBM wells is reported to the EUB. At present the EUB does not specifically track which companies are producing the small volumes of fresh water from shallow gas wells completed in sands, so it is not known how many shallow gas wells are producing fresh water. The EUB is currently working on capturing this information. Identifying these wells and recording the volume of fresh water being removed is essential. They should be managed in the same way as shallow CBM wells, since the effects on shallow aquifers will be cumulative.

Another issue that requires attention is the potential impact of voidage in conventional shallow gas pools. When the gas is removed, water will gradually infiltrate the space left by the gas. Some stakeholders believe the volume of water that percolates down to the shallow gas zone could be very large, yet this subject has so far received almost no attention.[63] There are considerable differences in opinions whether this is a problem that can occur over years or whether it would take a millennium for fluid to vertically move through the different rock formations. The water loss is offset in part by the re-injection of produced water.

The Pembina Institute thinks that the use of water by all branches of industry and by other users in the province should be reviewed to identify ways to encourage conservation. However, this report focuses on the use of water for oil recovery and the impacts that the oil industry has on Alberta's water resources. The next chapter explains how water is managed in the province and provides more detailed information on how much water is allocated and used by the oil industry.

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[62] Bev Yee, Assistant Deputy Minister, Alberta Environment, personal communication, November 30, 2005.

[63] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 24, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf Peachey's initial estimate is that gas recovered from shallow (less than 500 m) zones in Alberta would require 10–15 billion m^3 of water to refill the pools vs. 2.2 billion m^3 for all the oil produced in the province to date. If it is assumed that the average water-to-gas replacement ratio in the Western Canada Sedimentary Basin is 10 m^3 of water per 1000 m^3 of gas then almost 2,000 million m^3/yr of water will be required to replace annual gas production. To put these volumes into perspective, Alberta Environment estimates that the total annual groundwater recharge rate, province-wide, is about only 15 billion m^3/yr (this figure is from David Trew, Alberta Environment, Presentation to Insight Press conference, March 22, 2004).

2. Water allocation and use

To understand the management of water in Alberta, it is first necessary to briefly examine the principles and legislation that govern water in the province (section 2.1). We next describe Alberta's oil resources (section 2.2) and examine how water is used by the oil industry (section 2.3). Finally, we provide statistics on current water use in the province, particularly on the use of water by the oil industry (section 2.4). In each section we start with oil sands mining, then examine in situ production of bitumen and end with conventional oil recovery.

2.1 How water is allocated and managed in Alberta

In Canada, water policy and programming is mainly the responsibility of provincial governments. The government of Alberta "owns the rights to all water within its borders, and through legislation, regulates all developments and activities that might impact rivers, lakes and groundwater."[64] The key piece of legislation relating to water management in the province is the *Water Act*, which in 1999 replaced the *Water Resources Act*. The *Water Act* applies to all surface water and groundwater. However, in the regulations, saline water is exempt from the requirement for a licence so, at the present time, the *Water Act* applies mainly to fresh water.

The regulations and policies contained in the *Water Act* define the requirements for water use in Alberta, and also define the rights of licensed users.

Within the provincial government, Alberta Environment is the provincial department responsible for managing Alberta's water resources and implementing the *Water Act*. Through the *Water Act*, Alberta Environment allocates and manages water by requiring individuals, corporations (including companies producing oil) and municipalities to apply for a licence that authorizes the diversion and use of a specific amount of fresh water.[65] Each licence specifies a maximum amount of water that can be diverted and used by the holder of the licence within a certain time period.[66] The amount of water, referred to as a water allocation, remains under the authority of the province.

In Alberta, water allocations are granted on the basis of the *first in time, first in right* principle. This principle, which has existed in Alberta since 1894, means that water diversion and use of water are prioritized according to the age of a licence, rather than the intended water use: the older the licence, the higher the priority.[67] No distinction is made between the various uses to

[64] Alberta Association of Municipal Districts and Counties. 2003. *Backgrounder on Water Issues.* Alberta: AAMD&C. See also the *Water Act, section 3(2),* with respect to Crown ownership of water and the right to divert it.

[65] The *Water Act* applies only to fresh (non-saline) water, from surface water or groundwater. The requirement to hold a licence does not apply to a specified volume of water for household use and for traditional agricultural purposes, although traditional agricultural users were required to register their rights. The EUB requires a company to report on the volumes of water they actually use and now identifies whether this water is fresh or saline.

[66] Note that, because allocations represent the maximum amount of water that can be used or diverted, they do not represent actual water use.

[67] Government of Alberta. 2004. *Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta,* http://www.waterforlife.gov.ab.ca/html/removed.html

which the water may be put, with the exception of household use, which has priority over all other uses. This is the case for both surface water and groundwater.

When water licences were granted under the *Water Resources Act*, they had no expiry date. Under the *Water Act* this has changed. New water licences may be issued for a fixed period of time and are renewable at the end of the licence term (subject to review and established regulations). Generally, Alberta Environment grants a renewable licence for up to ten years,[68] sufficient to meet routine operations (with a separate temporary licence to meet additional water requirements during start-up).[69] Water management plans may increase or decrease licence terms in a specific basin, if the plan is authorized by the legislature (an “Approved Water Management Plan”).

The requirements for obtaining a licence vary, depending on the water use, water source (surface or ground) and the geographic region in which the water will be used. Before a water licence is issued, the *Water Act* requires an evaluation of the potential impacts of the water diversion on the environment and other water users. Alberta Environment has to consider such factors as natural water supply, environmental needs, existing apportionment agreements with other jurisdictions and existing licences.[70] The government of Alberta collects a nominal licence fee when water allocations are issued. The fee, which covers a portion of administrative costs, depends on the size of the water allocation (but not the actual volume of water used or diverted).[71]

The licence conditions described above apply to the oil and gas sector in the same way as to other sectors.[72] In Alberta, water licences have been issued to companies that inject fresh water underground since the 1950s. Several hundred licences issued to oil companies under the *Water Resources Act* are still in force and allow the holder to continue using the water for the intended purpose in perpetuity. [73] These “grandfathered” licences have not been subject to re-evaluation or re-assessment for potential environmental impacts or the appropriateness of the magnitude of the allocation.[74] The *Advisory Committee on Water Use Practice and Policy* addressed this in their recommendations, by asking for a voluntary review of permanent licences.[75] Term licences for

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[68] *Water (Ministerial) Regulation, section 12(4).*

[69] *Water (Ministerial) Regulation, section 12*. A licence may be granted for more than ten years, if certain conditions are met, as specified in this section of the regulation.

[70] *Water Act, section 51*.

[71] Alberta Environment. Undated. *Water Act Fact Sheet: Approvals and Licences*. The fee for volumes over 112,500 m^3/year and up to 125,000 m^3/year is $150. http://www3.gov.ab.ca/env/water/legislation/factsheets/generalinfo.pdf

[72] Alberta Environment. 2004. *Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta.* http://www.waterforlife.gov.ab.ca/html/removed.html#report

[73] A licence issued under the *Water Resources Act* can be cancelled if the project for which the licence was issued comes to an end. Either the licencee can request that it be cancelled or, under the *Water Act, section 55(1)*,the director may cancel the licence if no water has been diverted over a period of three years and there is no reasonable prospect that the licencee will resume diversion.

[74] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta’s Water Resources.* Drayton Valley, AB: Pembina Institute, http://www.pembina.org

[75] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report*, p. 9, 19 and 23; http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf In 2004 there were 336 permanent licences using water for underground injection, compared with 292 term licences, all of which are due for renewal by 2007. More information about this committee can be found at http://www.waterforlife.gov.ab.ca/html/removed.html

enhanced oil recovery (EOR), issued under the *Water Act*, expire; some were due for renewal in 2005, with the remainder requiring review prior to 2007.[76]

Since the early 1990s, the requirements for licences for groundwater have depended on the location of a project. Projects located in the "White Area" of the province (all areas primarily used for agriculture) have been subject to different regulations than projects located in the "Green Area" of the province (the forested north region and the region along the Rocky Mountains).[77] Within the White Area, the *Ground Water Allocation Policy for Oilfield Injection Purposes* has been in effect.[78] Under this policy, oil and gas companies were required to evaluate alternative sources to groundwater. Alternative sources included surface water, non-potable groundwater[79] and non-water alternatives. Alberta Environment could refuse the use of groundwater if alternative sources were considered feasible. The policy for the White Area did not apply in the Green Area. However, Alberta Environment's new *Water Conservation and Allocation Guideline for Oilfield Injection* requires all companies to look for alternatives before they apply for a freshwater licence (the search must be most rigorous in water-short areas).[80]

The volume of groundwater allocated for EOR under an Alberta Environment licence is not to exceed 50% of the long-term yield of a given aquifer.[81] This is monitored at an observation well 150 metres from the withdrawal well. Initial approvals are for one year so that the aquifer may be monitored, but subsequently the licence can be renewed for five-year periods. While the *Water Act* is specific to the issuance of licences and approvals for water projects, the *Environmental Protection and Enhancement Act* (EPEA) may also apply to projects that use water.[82] An approval under EPEA is required for oil sands mining and processing plants, for the enhanced recovery of in situ oil sands and for heavy oil processing plants.[83] A landfill that stores waste from a water treatment process will require an approval or registration, depending on its size, location and the substances contained in the waste.[84]

Alberta Environment is the lead regulator of fresh water but the EUB assists by regulating water requirements for thermal enhanced recovery operations. The EUB is responsible for overall

[76] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report.* p. 17. http://www.waterforlife.gov.ab.ca/html/removed.html#report Note that Alberta Environment's licences for EOR include licences for both conventional EOR and the in situ recovery of bitumen.

[77] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources.* Drayton Valley, AB: Pembina Institute.

[78] Alberta Environment. 1990. *Ground Water Allocation for Oilfield Injection Announced*, News Release and Fact Sheet, March 27. This is reproduced as Appendix A in Alberta Environment. 2003. *Groundwater Evaluation Guideline: Information Required When Submitting an Application under the Water Act*, http://www3.gov.ab.ca/env/water/Legislation/Guidelines/index.cfm See Glossary for more information on aquifer and other terms.

[79] Potable groundwater should have no more than 500 mg/l TDS. Health Canada. 2006. *Guidelines for Canadian Drinking Water Quality – Summary Table*, http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html Fresh (non-saline) water has up to 4,000 mg/l TDS, based on the Alberta definition of saline water.

[80] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection*, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[81] Alberta Environment. 1990. *Ground Water Allocation for Oilfield Injection Announced*, News Release and Fact Sheet, March 27. This is reproduced as Appendix A in Alberta Environment. 2003. *Groundwater Evaluation Guidelines: Information Required when Submitting an Application under the Water Act*, http://www3.gov.ab.ca/env/water/Legislation/Guidelines/index.cfm

[82] *Water Act, section 5.*

[83] *Environmental Protection and Enhancement Act, Schedule 1, Division 2, Part 8 and Division 3(b).*

[84] *Environmental Protection and Enhancement Act, Schedule 1, Division1.*

regulation of oil and bitumen recovery. It also regulates other oilfield activities to protect surface water and groundwater from leaks, spills and so on. The *Oil and Gas Conservation Act and Regulations* set out the requirements for the recovery of conventional oil, and EUB *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* stipulates requirements for enhanced recovery from conventional wells and the disposal of any waste water (such as produced saline water).[85] EUB *Directive 051: Disposal and Injection Wells* applies to wells that require steam injection to recover bitumen, wells that inject water to recover conventional oil and bitumen and also disposal wells. It specifies procedures and practices designed to protect the subsurface environment, including all usable groundwater.

Although Alberta Environment requires some reporting of water use from large projects, the department has not continuously monitored water use.[86] The EUB has detailed records of water sources and use by the oil industry since about 1970.[87] Water source withdrawal volumes are reported monthly as part of the EUB's measurement and reporting system.[88] Information is reported for all water source points, which include surface lakes and rivers, and wells deeper than 150 metres, irrespective of whether they are licensed by the EUB. However, the EUB records do not distinguish between fresh and saline groundwater.[89] Staff assessment of the EUB licensed shallow wells is needed to identify non-saline volumes for shallow wells. Unlicensed shallow wells are classified as non-saline. The records have been accessed periodically by Alberta Environment and others to gauge trends, but the system was not user-friendly and users required assistance from EUB staff to extract information. However, this was the only source of information that Alberta Environment could use to assess, with regional supply information, the potential impacts of withdrawal. Only recently, as a result of the *Water for Life* strategy, are Alberta Environment staff able to work on improving their information systems. Unless they are small test projects, oil sands projects (both mines and in situ recovery) require an environmental impact assessment (EIA) before they can be approved. Conventional oil wells are exempt from EIAs.[90] If a project is approved following the EIA review, and possibly a hearing, both the EUB and Alberta Environment will issue licences and approvals. Alberta Environment issues a licence if water is to be used, and an approval if water is diverted but not used.

Until recently, when Alberta Environment granted a water licence for an oil sands mining project, the allocation was based on the anticipated demand at the start-up of the operation. For oil sands mining projects, the start-up period requires substantially more water (approximately 30% more)[91] than is necessary for routine operations, which can draw upon recycled water in

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[85] EUB directives can be found at http://www.eub.gov.ab.ca/BBS/requirements/directives/default.htm EUB directives were formerly called guides. When renamed, they retained the same numbers.

[86] Major withdrawal sites in the Cold Lake area have numerous wells on site to monitor the effects of drawdown near the pumping centres and towards the edge of their lease, but there is no comprehensive network of monitoring wells across northern Alberta.

[87] Water source/use records were initially intended to be for oilfield injection only, but they record all water use by the oil industry and are the most comprehensive source of historic data.

[88] Alberta Energy and Utilities Board. 2001. Directive 007. *Production Accounting Handbook.* This handbook should be used in conjunction with the 2002 *Draft for Stakeholder Feedback,* which reflects changes due to the implementation of the Petroleum Registry.

[89] The data for wells are not recorded by the 4,000 mg/l TDS criteria that distinguishes saline water under the *Water Act.* Also, although the EUB now records wells deeper than 150 metres, some older wells with depths of less than 150 metres also reside in the EUB database.

[90] *Environmental Assessment (Mandatory and Exempted Activities) Regulation. AR 111/93. Schedule 1 Mandatory Activities, sections (i) and(j);* A commercial oil sands, heavy oil extraction, upgrading or processing plant requires an EIA if it produces more than 2,000 cubic metres of crude bitumen or its derivatives per day. See also *Schedule 2 Exempted Activities, section (e),* http://www.qp. gov.ab.ca/catalogue/catalog_results.cfm

[91] For example, the water licence granted for Canadian Natural Resources' Horizon oil sands mine allocated 89.1 million m^3/year for start-up operations and 61.3 million m^3/year for routine operations.

addition to water withdrawn from the Athabasca River. The practice of granting water licences at the volume required for start-up, as was done under the *Water Resources Act*, allowed Suncor and Syncrude to implement numerous large-scale expansions and new projects without applying for a new licence. Alberta Environment has recently implemented a new approach to allocations for projects with water requirements that vary considerably over time. For example, new water licences (e.g., Canadian Natural Resources Limited's (CNRL's) Horizon mine and upgrader facility and Shell's Jackpine Mine)[92] allocate the volume of water in a phased manner that reflects the changing water requirements through the various stages of a project's operations.

Since 1989, Alberta Environment and the EUB have required water recycling for all in situ projects using more than 500,000 m^3/year water, writing the recycle rates into the approval for a scheme.[93] The *Water Conservation and Allocation Guideline for Oilfield Injection* states that water recycling is the expected industry practice in all operations.[94]

The federal government also has a role with respect to water management. The two key pieces of legislation relevant to water management at the federal level are the *Navigable Waters Protection Act* and the *Fisheries Act*. These can impact road, bridge, culvert and water intake repairs or construction to the extent that the affected water bodies are navigable or fish bearing. In addition, the *Canadian Environmental Protection Act* provides protection from the release of toxic substances into water bodies. Finally, although they do not have the status of legislation, by provincial law Health Canada's *Guidelines for Canadian Drinking Water Quality* apply to water for consumption in Alberta.[95]

2.2 Alberta's oil resources

The location of Alberta's extensive oil sands and conventional oil deposits is shown in Figure 2-1. Fluid (conventional) oil deposits occur over large areas of the province. The oil sands deposits, in which the oil is in a solid or semi-solid form known as bitumen, are located in three areas of northern Alberta.

[92] For example, see CNRL's Licence No. 00186921-00-00 or Shell's Licence No. 001861757-00-00 at http://www3.gov.ab.ca/env/water/approvalviewer.html.

[93] Alberta Energy and Utilities Board. 1989. *Water Recycle Guidelines and Water Information Reporting for In Situ Oil Sands Facilities in Alberta*, http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il89-05.htm

[94] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection*, p. 20, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[95] Health Canada. 2006. *Guidelines for Canadian Drinking Water Quality – Summary Table*, http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/chemical-chimiques_e.html#t4 See also Alberta Association of Municipal Districts and Counties. 2003. *Backgrounder on Water Issues*. Alberta: AAMD&C.

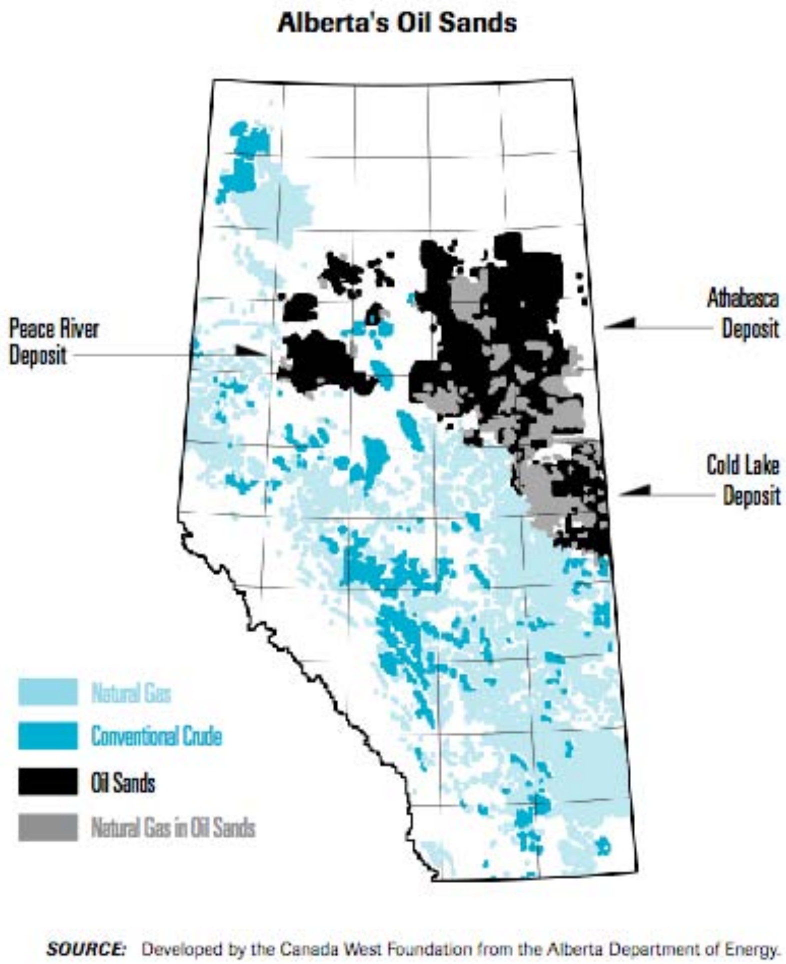

Figure 2-1 Location of oil and oil sands in Alberta

Source: Canada West Foundation, with permission

The process used for the extraction of the oil depends on whether it is fluid or in the form of bitumen. It also depends on the location and depth of the resource. Initially, conventional oil and some heavy oil (or less viscous bitumen) can be pumped directly from the ground. This is called primary production.[96] As the oil is removed, secondary recovery is often implemented to extend the life of a pool. In many cases, this enhanced recovery involves the injection of water or (in the case of bitumen) steam into the formation. There are two basic categories of enhanced recovery: EOR of conventional oil, and in situ enhanced recovery to extract bitumen from the oil sands.[97]

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[96] In some cases bitumen will flow to the well bore without the introduction of heat, when co-produced with sand through the use of progressive cavity pumps. This type of production is often called cold heavy oil production with sand (CHOPS). See Alberta Energy. 2004. *Alberta's Oil Sands*, http://www.energy.gov.ab.ca/docs/oilsands/pdfs/osgenbrf.pdf In 2004 approximately one-third of in situ production in Alberta was from primary "cold" recovery and two-thirds was recovered through thermal methods. Alberta Economic Development. 2005. *Oil Sands Industry Update*, p.3. http://www.alberta-canada.com/oandg/files/pdf/oilSandsUpdate_Dec2005.pdf

[97] Some oil sands may be recovered by primary recovery schemes, but in other cases production is initiated using enhanced recovery methods. See Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, p. 2-9, http://www.eub.gov.ab.ca/bbs/default.htm

Where bitumen is close to the surface, it can be mined. As mentioned in Chapter 1, conventional oil resources, which were the main source of production in the past, are becoming depleted and the main remaining established reserves are in the oil sands. The total remaining reserves are shown in Table 2-1.

Table 2-1 Alberta's conventional oil and oil sands volume in place, established reserves, production and ultimate potential, 2004[98]

All units in billion m^3	Initial volume in place[99]	Initial established reserves[100]	Cumulative production to end of 2003	Remaining established reserves	Production in 2003	Ultimate potential[101]
Conventional crude oil	10.0	2.7	2.4	0.25	0.04	3.1
Oil sands (total)	269.9	28.4	0.7	27.7	0.06	50.0
Total mineable	17.5	5.6	0.5	5.1	0.04	10.1
Total in situ	252.5	22.8	0.2	22.6	0.02	39.6
Athabasca (total in situ and mineable)	217.5	—[102]	0.5	—	—	—
Cold Lake (total)	31.9	—	0.2	—	—	—
Peace River (total)	20.5	—	0.01	—	—	—

The oil sands mining projects and those using in situ methods are identified in Figure 2-2.

[98] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, Overview, p. 2 and p. 2-2 and 2-9 , http://www.eub.gov.ab.ca/bbs/default.htm Selected figures are given in this table. For figures on the in situ reserves in areas under active development, see p. 2-9.

[99] Initial volume in place is the volume estimated to be in the ground, before any has been produced. This and other categories are those used by the Alberta Energy and Utilities Board. Not all this volume will be recoverable.

[100] Initial established reserves are those reserves that are recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical or similar information with reasonable certainty.

[101] Ultimate potential is an estimate of the initial established reserves that will have been developed in an area by the time all the exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions.

[102] The EUB report that is the source for this table does not provide all figures on a regional basis, only for the areas under active development, which would not be comparable with other figures in the table. Additional information on the regions can be found in Table 2-5, on p. 2-9, in *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98.

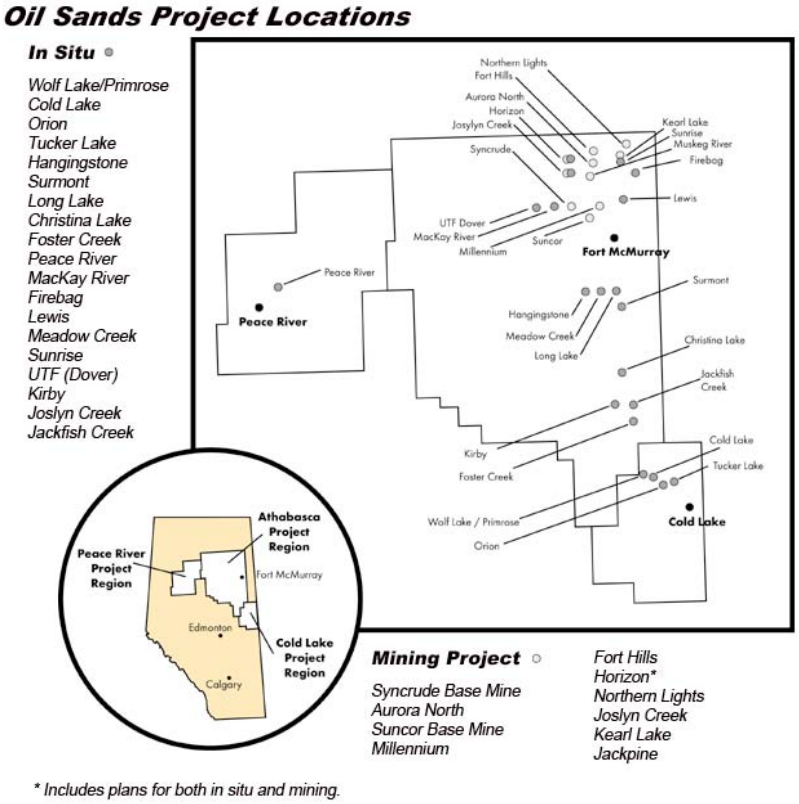

Figure 2-2 Location of mining and in situ recovery of oil sands

Source: National Energy Board, with permission[103]

Oil sands mining: Oil sands mining operations are limited to deposits of bitumen located under less than 75 metres of overburden. Alberta's surface mineable oil sands underlie approximately 286,000 hectares (ha) (or 37 townships) of the Athabasca Oil Sands Region. They are estimated to contain 17.5 billion m^3 of initial oil in place.[104] Of this total the EUB currently estimates that initial established reserves are 5.6 billion m^3, approximately one-third of the initial volume in place.[105]

Although the EUB estimates that only 18% of the remaining established bitumen reserves is accessible through surface mining, it projects that oil sands mining will continue to dominate bitumen production over the next decade, still accounting for approximately 64% of the bitumen production in 2014. However, by 2014, mining output is expected to be 232% greater than in

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[103] The boundary between the oil sands regions in this map was based on the EUB definition of the three oil sands areas in the province. On this basis, EnCana's Foster Creek project is in the Athabasca Oil Sands Area, even though it is located in the Cold Lake weapons range and is included in reports on the Cold Lake region.

[104] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-2. http://www.eub.gov.ab.ca/bbs/default.htm

[105] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-2, http://www.eub.gov.ab.ca/bbs/default.htm

2004, with 260,000 m^3 per day of bitumen from mining operations (compared to 148,000 m^3 per day from in situ operations).[106]

In situ enhanced recovery of bitumen: In situ recovery refers to all bitumen recovery other than mining. Some deep deposits of bitumen can be removed using primary recovery, similar to conventional crude oil production,[107] but most deposits require some form of enhanced recovery. This has traditionally involved the injection of steam into the bitumen found in oil sands deposits. The steam heats the bitumen, making it less viscous, so that it can be pumped to the surface together with much of the water generated by the cooling of the injected steam.

This in situ recovery is often referred to as “thermal recovery,” to distinguish it from conventional enhanced recovery of crude oil, which uses cold water.[108] However, since 2001 a few projects have been using cold (mostly saline) water for the in situ recovery of bitumen.[109] In this report we use the general term “in situ”, unless we want to distinguish between the processes using cold water and steam, when we refer to “thermal” recovery. New processes are being developed that use a solvent instead of steam; these would not be referred to as thermal recovery, unless the solvent were used in conjunction with heat. Other thermal processes are being developed that similarly do not use water (see Chapter 4).

In situ recovery methods are used to extract bitumen in the Cold Lake and Peace River deposits and in those parts of the Athabasca region where the bitumen is too deep to mine (see Figures 2-1 and 2-2). In 2004, in situ production accounted for less than 35% of total oil sands production to date, with the rest coming from mining. However, the EUB estimates that about 82% of the remaining established bitumen reserves will be accessed using in situ methods (22.6 billion m^3 from a total 27.7 billion m^3).[110] At the end of 2004, the cumulative production from in situ methods was 230 million m^3 with 84% coming from the Cold Lake oil sands area (Table 2-1).

Enhanced oil recovery (EOR): EOR involves injecting a substance (most commonly water) into oil reservoirs to maintain the pressure in the formation so that more oil can be extracted. In a water flood operation, the water is injected into re-completed existing wells, or wells drilled and completed specifically for the purpose of injection, and displaces oil to surrounding conventional oil wells for production to the surface. Water has been used for EOR at conventional wells across the province for several decades.

While water can be used to enhance the recovery of conventional oil as a well ages, it is an essential element right from the start of oil sands mining operations and in all in situ operations

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[106] Alberta Energy and Utilities Board. 2005. *Alberta’s Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-16 and 2-17, http://www.eub.gov.ab.ca/bbs/default.htm

[107] Alberta Energy and Utilities Board. 2005. *Alberta’s Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-13, http://www.eub.gov.ab.ca/bbs/default.htm

[108] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* http://www.waterforlife.gov.ab.ca/html/removed.html

[109] EnCana and CNRL both use saline water for their cold recovery projects at Brintnell.

[110] Alberta Energy and Utilities Board. 2005. *Alberta’s Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-2 for ultimate potential, http://www.eub.gov.ab.ca/bbs/default.htm Traditionally, oil and bitumen have been measured in barrels, the Imperial measure. In this report we have followed the Alberta Energy and Utilities Board and used metric measure. To convert cubic metres of oil to Canadian oil barrels, multiply by 6.2929. For water, 1 m^3 of water is equivalent to 6.2901 barrels. See Alberta Energy Utilities Board. 2005. *Alberta’s Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. A-9.

that use steam. Indeed, it has been said, *"Process water is the lifeblood of an oilsands operation."*[111] The next section shows why.

2.3 Ways in which water is used

Water is used for drilling wells, for enhanced recovery from conventional wells and for the recovery of bitumen. Both oil sands mining and in situ oil sands recovery require large amounts of water, for processing and upgrading in the case of mining and to generate steam for in situ production. The cumulative impact of the increasing demand for water by the oil industry is a major environmental concern.

2.3.1 Oil sands mining and upgrading

Water use by mining operations has been identified as one of the key challenges facing the industry.[112] Although surface mineable bitumen only represents 6.5% of the total volume of bitumen in place, it represents 18.4% of the remaining established reserves.[113] This is because the recovery rate of bitumen through mining is higher than for in situ processes.[114]

In section 1.4 it was stated that oil sands mining operations require 2 to 4.5 m^3 of water (net) to produce a cubic metre of SCO. In fact, about 10 m^3 of water is required to obtain one cubic metre of SCO, but the net volume of make-up water is less, due to the use of recycled water.[115] There is, however, a considerable range in water requirements between companies. In 2004, the net requirement for the production of bitumen at three mining operations ranged from less than 2 m^3 to more than 3.5 m^3.[116] When water for upgrading the bitumen to SCO was included, the net figures ranged from 2.2 to 4.4 m^3 water for 1 m^3 SCO.

The four predominant sources of water used at oil sands mining operations are the Athabasca River and smaller tributary rivers, groundwater from wells and surficial water, water from precipitation (rain and snow melt) and connate water.[117,118] The scale and growth of oil sands mining poses significant water use and management challenges that will need to be overcome to prevent significant environmental impacts. Oil sands mining operations impact water resources in a number of ways, both directly and indirectly, as a result of muskeg and overburden drainage,

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[111] National Energy Board. 2004. *Canada's Oil Sands: Opportunities and Challenges to 2015, An Energy Market Assessment,* p. 65, http://www.neb-one.gc.ca/energy/EnergyReports/EMAOil sandsOpportunitiesChallenges2015/EMAOil sandsOpportunities2015QA_e.htm

[112] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 21, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/Oil_Sands_Technology_Roadmap. htm

[113] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2-2, http://www.eub.gov.ab.ca/bbs/default.htm Percentages are calculated from figures in Table 2.1, p. 2-2.

[114] The bitumen recovery rate for mining operations is generally 90% or higher, whereas in situ oil sands operations generally achieve between 25% and 60% recovery. Source: Centre for Energy website, http://www.centreforenergy.com/generator.asp?xml=/silos/ong/oilsands/oilsandsAndHeavyOilOverview06bXML.asp&template=1,1,1

[115] Isaacs, Eddy. 2005. *Canadian Oil Sands: Development and Future Outlook,* IV International Workshop on Oil and Gas Depletion, Lisbon, May 2005. p. 2, http://www.aeri.ab.ca/ OR http://www.aeri.ab.ca/sec/new_res/docs/oil_sands_dev_outlook_Isaacs_050214.pdf. Ratio confirmed by Eddy Isaacs, personal communication, August 15, 2005.

[116] Alberta Energy Utilities Board, personal communication, February 8, 2006. In 2004, the Albian Sands, Suncor and Syncrude mining operations used on average 2.62 m^3 water to produce 1 m^3 of bitumen; when upgrading of bitumen to SCO is included, the overall average is 4.04 m^3 water.

[117] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 11.

[118] Connate water is water trapped in the pores of rock during its formation, which comes to the surface with the bitumen.

basal aquifer dewatering, withdrawal of water from the Athabasca River and management of tailings.

2.3.1.1 Mine site preparation—Muskeg and overburden drainage

Before surface mining can begin the forest and wetlands must be cleared and drained so that the material overlying the bitumen, the overburden, can be stripped away. Wetlands cover a significant portion of the undisturbed landscape in the oil sands region, with bog and fen peatlands being the characteristic wetland found in the region.[119] Drainage of these wetlands and peatlands is achieved using a technique known as ditching, which involves digging one- to two-metre-deep drainage ditches approximately 100 metres apart, and can take up to three years to complete. In some instances the overburden sands contain water to a significant depth, and sumps or wells with drainage pumps are required to remove the water.[120] Because this water has not been in contact with oil sands it is usually released through polishing ponds, which allow suspended sediments to settle out, before it drains into tributaries (creeks, streams) and the Athabasca River. However, some operators use this water as a source of process water or spray it on exposed soil surfaces to reduce dust.[121,122]

Alberta Environment does not consider drainage of water from muskeg or overburden to be a diversion under the *Water Act*,[123,124] and hence does not require oil sands mine operators to collect data on how much water is drained into tributaries. However, an approval is required from Alberta Environment for the construction and operation of the drainage projects. If an operator wishes to retain and use muskeg drainage water, a licence is required.[125]

2.3.1.2 Basal aquifer depressurization and mine drainage

In addition to draining water out of the overburden, it is often necessary to depressurize the basal aquifer and to actively drain the mine pit area of runoff and seepage water to prevent flooding of the mine pit. The quality of the basal depressurization water varies, but is usually brackish and high in TDS and, because it has come into contact with oil sands, cannot be released directly to the environment.

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[119] Alberta Environment. 2000. Guideline for wetland re-establishment on reclaimed oil sands leases. *Conservation and Reclamation Information Letter 00-2*, http://www3.gov.ab.ca/env/protenf/landrec/documents/2000-2.pdf

[120] Ditches are used to drain areas less than four to five metres deep; sumps are used for water-bearing deposits five to ten metres deep and wells are used for water-bearing deposits deeper than ten metres. Source: Shell Canada Ltd. 2005. *Application for the Muskeg River Mine Expansion,* p. 10-6.

[121] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 12.

[122] In discussing water use for bitumen extraction at the Albian Sands Muskeg River Mine, Shell Canada Ltd. states, “The primary source is the Athabasca River, but we also use other sources such as muskeg drainage.” Source: Shell Canada Ltd. 2005. *2004 Sustainable Development Report,* p. 25.

[123] Under section 1(1)(m) of the *Water Act,* a “diversion of water” is defined as “(i) the impoundment, storage, consumption, taking or removal of water for any purpose, except the taking or removal for the sole purpose of removing an ice jam, drainage, flood control, erosion control or channel realignment, and (ii) any other thing defined as a diversion in the regulations for the purposes of this Act.”

[124] Marriott, Pat. 2004. *Water in the Oil Sands Industry*. Presented at the CONRAD Oil Sands Water Usage Workshop, February 24–25, 2004.

[125] Pat Marriott, Alberta Environment, personal communication, September 15, 2005.

An exception to this practice was recently made when Alberta Environment granted permission to CNRL to dispose of the depressurization water from its Horizon Mine into the same aquifer from which the water was extracted due to its high suspended solid content.[126]

2.3.1.3 Oil sands extraction and tailings management

2.3.1.3.1 Extraction

The current oil sands extraction process used at oil sands mines is dependent on substantial volumes of water to separate the bitumen from the sand. At its simplest, the bitumen extraction process is best characterized as using hot water to wash oil from sand. The tailings by-product of bitumen extraction, composed of water, sand, fine clay particles and residual bitumen, also poses significant water management challenges. Despite the growing prominence of stakeholder concern with water use for oil sands extraction, the Alberta Chamber of Resources has suggested it is unlikely any major breakthroughs or alternatives to water-based bitumen extraction will emerge by 2030.[127]

While raw oil sands used to be transported to the bitumen extraction facility by conveyor belt, a newer technology called hydrotransport is now being utilized. With hydrotransport, hot water (and sometimes caustic soda) is mixed with the mined oil sands to produce a slurry that can be pumped through a pipeline to the bitumen extraction facility. The hot water is added to process the bitumen, and the caustic soda aids in the separation process.[128] The mixing that occurs in the pipeline is the first component of the extraction process. The slurry is then pumped into large primary separation vessels in which the slurry settles into layers composed of, from top down, bitumen froth, middlings (comprising bitumen, clay and water), and sand and water, or tailings. The bitumen froth is skimmed off of the top and sent to froth treatment, the middlings are fed into a secondary separation vessel to undergo more separation, and the tailings are transported by pipeline to the tailings pond. The froth treatment facility uses centrifuges or other separating devices and the addition of a diluent (naphtha or paraffin) to further separate remaining water, sand and clay from the bitumen froth. The diluent is then recovered, the clay, water and sand are pumped to the tailings pond and the extracted bitumen is transported to storage tanks or to an upgrading facility.

Averaged for all existing oil sands mining operations, the quantity of water required for the extraction process is approximately 0.7 m^3 of water per tonne of processed ore, or 2.62 m^3 per cubic metre of bitumen.[129,130] As much as possible mine operators use free water[131] from the tailings ponds for the extraction process.[132] However, as was noted at the beginning of section

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[126] *Alberta Environmental Protection and Enhancement Act Approval for Construction, Operation and Reclamation of the CNRL Horizon Oil Sands Processing Plant and Mine,* Approval No. 149968-00-01, April 6, 2004, section 4.7.1 (p).

[127] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 3.

[128] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 9.

[129] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 17.

[130] Alberta Energy Utilities Board, personal communication, February 8, 2006.

[131] The “free water” that can be recycled from tailings ponds represents the fraction of water not trapped in the tailings materials.

[132] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 18.

2.3.1, even after this recycled water is accounted for, oil sands extraction still requires anywhere from 2 to just over 3.5 m^3 of water from the Athabasca River to produce 1 m^3 of bitumen.[133]

2.3.1.3.2 Tailings management

Within oil sands deposits each grain of sand is surrounded by a water film that contains silt and clay, which in turn is surrounded by a layer of bitumen. As the name implies, oil sands are mostly made up of sand, with only 10 to 12% bitumen and 3 to 5% water content. As described in the preceding section, after the bitumen is extracted from the oil sand a waste stream of tailings is produced. Tailings comprise coarse grains of sand, fine sand and clays, the water that was originally with the oil sand (called connate water), the remaining hot water that was used in the extraction process and some residual bitumen. Depending on the quality of the oil sands being processed (bitumen and fines (small particles of silt and clay) content), between 3 and 5 m^3 of water are stored in tailings for every cubic metre of bitumen.[134]

Oil sands mining operations abide by a zero-discharge policy, so tailings are pumped from the extraction facility to tailings ponds where they are deposited and left to separate and settle. Dependent upon the tailings management and technologies employed, and the proportion of fines in the mined oil sands, it is estimated that this settling can take anywhere from a few decades to as much as125–150 years.[135] Referring to these vast storage facilities as ponds is somewhat of a misnomer given that they are some of the largest human-made structures in the world[136] and already cover an area of over 50 square kilometres.[137]

When mining projects first begin operating it is necessary to build tailings ponds outside of the mine pits, through the construction of large dykes. However, as the operation progresses the tailings facilities move into the mined-out pits. When tailings are deposited into the tailings facilities the water-suspended fine sand and clays form a slurry that separates from the coarser sand. This slurry settles to become less liquid and more dense over time, reaching approximately 30% by weight of fine sand and clays. The remaining 70% is composed of water that cannot be recycled due to these suspended sediments.[138] This settled tailings slurry is referred to as mature fine tailings (MFT). In essence, the production of MFT ties up water and therefore limits the availability of recycle water. Similarly, the coarse sand beach created when tailings are deposited stays wet as the space left by the removal of the bitumen is filled by water that sits between the sand grains. When considered together, MFT and coarse tailings represent a significant consumption of water that cannot be recycled in oil sands mining operations. In light of this, oil sands operators have made efforts to produce non-segregating tailings, also called consolidated

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[133] Alberta Energy Utilities Board, personal communication, February 8, 2006.

[134] Bruce Peachey, personal communication, September 13, 2005.

[135] Fedorak, P.M., D.L. Coy, M.J. Salloum and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology,* Vol. 48, p. 21–33.

[136] The largest tailings pond at Syncrude Canada Ltd. is the Mildred Lake Settling Basin, which has a water surface of 13 km^2 and contains over $400 \times 10^6 m^3$ of fine tailings. Source: Fedorak, P.M., D.L. Coy, M.J. Salloum and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology,* Vol. 48, p. 21–33.

[137] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 34, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[138] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 19.

tailings (CT), in which the fines remain with the coarse sand and occupy the space that would otherwise be filled with water.[139] This allows the water to be recycled back into the operation.

2.3.1.3.3 Recycle

The extent to which oil sands mining operations can recycle process water is determined by a variety of factors and varies from one operation to another. The tailings facilities play a central role in water management as they provide a means for settling fine materials, thereby making water that is not bound up in the coarse sands or MFT available for recycle. Water available for recycle overlies the MFT and is referred to as the free water inventory. Because the free water overlies a layer of MFT, a sufficient depth of water (approximately three metres) needs to be maintained so that heavy wind movement doesn't cause fines to be re-suspended in the free water.

2.3.1.4 Oil sands upgrading

In addition to the water required to extract the bitumen from the oil sands, water is also needed to upgrade the bitumen into lighter SCO that can then be transported by pipeline to a refinery. The process of upgrading involves breaking the long, heavy molecules of bitumen into smaller ones and removing impurities including sulphur, nitrogen and carbon.

First, bitumen is fed into either hydrocrackers where it is reacted with hydrogen under pressure, or into cokers where it is heated to high temperatures, both of which break down the bitumen into lighter molecules.[140] Next the cracked bitumen enters a fractionator that separates it into its various components (including gas, oil, kerosene, naphtha and sour gas) before undergoing hydrodesulphurization, which involves the addition of hydrogen and the removal of sulphur. The liquids produced are then stored separately before being mixed to form SCO that can be shipped to refineries outside of the oil sands region.

Water is used to produce the steam that is in turn used to produce hydrogen for use in hydrocracking and hydrodesulphurization. However, it is noteworthy that some upgrading processes use more hydrogen than others due to the various technologies employed. In addition, operators can choose to make different quality products that require either more or less hydrogen. Because the hydrogen ends up in the upgraded product there is a net loss of water from the site.[141]

2.3.1.5 Utilities water

Water that has a common use across different processes is referred to as utilities water. While not as obviously integral to an oil sands mining operation as the water used for bitumen extraction, utilities water is critical for the functioning of these complex mega-projects. Utilities water includes

- potable water for drinking water, showers and toilets;

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[139] To achieve non-segregated tailings, Suncor and Syncrude are using gypsum (calcium sulphate) as a coagulant to produce CT; Albian Sands is using mechanical thickeners to produce what it calls thickened tailings.

[140] This stage produces a number of by-products including coke (which is similar to coal), kerosene, naphtha and gas oil (in vapour).

[141] Rogers, Mike. 2005. *DRAFT Surface Oil Sands Water Management: Summary Report.* Prepared for the CEMA Surface Water Working Group, p. 24.

- utility water for cleaning trucks, equipment and facilities;
- fire water to fight any fires that may occur;
- boiler feedwater to produce steam for driving turbines to make power, heating, driving turbines to power motors, and making hydrogen for upgrading;
- cooling water for use in evaporative cooling systems; and
- gland water to operate pumps.

2.3.1.6 End pit lake filling

Once all the oil sands in an area have been mined the final mine pit will become an end pit lake (EPL), and the MFT not incorporated into consolidated tailings (CT) will be transferred to the bottom of the lake. Unlike the tailings ponds, which only have approximately five metres of water overlying the MFT, EPLs will be considerably deeper (65 to 100 metres) to prevent mixing of the MFT with surface waters.[142] In theory the EPLs will become viable aquatic ecosystems with active littoral zones, shallow wetlands and shoreline habitat that support biological activity and help biodegrade organic chemicals accumulating from runoff through the reclaimed landscape.[143] The reclaimed landscape will be contoured to drain into the EPL, which in turn will discharge into the Athabasca River watershed. This will allow organic chemicals and salts that accumulate in surface runoff passing over and through the tailings material incorporated into the reclaimed landscape to accumulate in the EPL where they will be diluted and biologically degraded over time.

The size and volume of an EPL depends upon the pit size and the amount of tailings material that it will contain. For example, the planned EPL for Suncor's Steepbank Mine will have a volume of approximately 285 million m^3 and will cover an area of 883 ha (approximately 3.4 sections) whereas the proposed Albian Sands EPL for the Muskeg River mine will have a volume of 130 million m^3 and cover an area of 442 ha.[144] Most of the EPLs proposed by oil sands mine operators will be filled with water from the Athabasca River between the end of mining and the end-of-mine closure.[145] Using water from the Athabasca River to fill the EPLs rather than relying on local runoff is driven by the need to regulate the filling time to ensure the creation of a biologically productive lake with biological processes that remediate any residual water contaminants. The cumulative withdrawal of water to fill EPLs for multiple oil sands mines may impose significant demands on the Athabasca River in the future. However, if filling schedules are properly managed they need not occur simultaneously, thereby minimizing this impact.

2.3.2 In situ oil sands recovery

In situ recovery is used where the bitumen is too deep to mine, but where there is sufficient caprock (i.e., the impervious rock that overlays the bitumen formation) to withstand the pressures

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[142] Oil Sands Environmental Research Network. *Virtual Mine End Pit Lake,* http://www.osern.rr.ualberta.ca/Virtual_Mine/index.asp?page=end_pit

[143] Oil Sands Environmental Research Network. *Virtual Mine End Pit Lake,* http://www.osern.rr.ualberta.ca/Virtual_Mine/index.asp?page=end_pit

[144] Oil Sands Environmental Research Network. *Virtual Mine End Pit Lake,* http://www.osern.rr.ualberta.ca/Virtual_Mine/index.asp?page=end_pit.

[145] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group, p. 28.

associated with in situ production. Heat, in the form of steam, is most commonly used to reduce the viscosity of the bitumen, so that it can be pumped to the surface. New processes that use solvents or other methods to extract the bitumen in situ are being developed and will be described in Chapter 4.[146]

There are two main processes for in situ bitumen recovery: cyclic steam stimulation and steam-assisted gravity drainage. While the size of individual projects varies considerably, both processes involve a high density of wells extending over one or more townships.[147] The initial net water requirement for in situ production is usually far less than for oil sands mining operations, and companies that recycle water often use much less than 0.5 m^3 for 1 m^3 of oil for the extraction process.[148] However, ultimately the ratio will probably be 1:1, as water slowly filters in from other formations (since all voids created by the removal of the oil will be filled by water or other substances; see section 3.3.1).

2.3.2.1 Cyclical steam stimulation

The CSS process requires a caprock and overburden of more than 300–400 metres to withstand the high pressure created by the steam.[149] It has been used in the Cold Lake and Peace River areas for more than 20 years.[150] In this process high pressure steam is injected into the bitumen-bearing formation through a combination of vertical and horizontal wells, as can be seen in Figure 2-3 (upper portion). After a period of soaking, the warmed bitumen flows towards the well bore and is pumped to the surface through the same well bore. Then the whole process starts again, with the “huff ‘n’ puff” cycles continuing until the oil recovery is no longer economic.[151] The recovered bitumen is diluted with condensate (pentanes and heavier liquid hydrocarbons obtained from natural gas production) and shipped by pipeline.

The steam condenses in the formation and most of it will be pumped to the surface with the fluidized bitumen. This “produced water,” as it is called, is de-oiled and treated so it can be recycled to generate steam for the next injection cycle. Additional water will be needed to

[146] Occasionally bitumen may be recovered in the same ways as conventional oil (e.g., BlackRock Ventures Inc. project at Seal, in the Peace River area).

[147] The Petro-Canada Meadow Creek SAGD project, for example, is planned to span 58 sections (15,025 ha or 37,120 acres), although the actual area disturbed will be about 3.7% of the total. Well pads alone, of which there will be 38 when the project is complete, will cover less than 2% of the total area, but underground the SAGD pipes will radiate to drain the bitumen from the lease area. Source: Petro-Canada. 2001. *Application for Approval of the Meadow Creek Project.* Imperial Oil’s Nabiye CSS expansion in the Cold Lake area, in comparison, will extend over 32 sections (8,290 ha or 20,480 acres) and approximately 3.2% of the area will be impacted by well pads. The company plans to have 95 pads, each with 24–28 wells, by the time the project is complete. The bottom-hole spacing of wells will be between 150 and 220 metres, but one surface facility of approximately 2.8 ha will be needed for each pad (95 pads x 2.8 ha = 266 ha, or 3.2% of the 8,290 ha project area). Source: Imperial Oil Resources. 2001. *Cold Lake Expansion Projects, Nabiye and Mahihkan North,* Vol. 1, p. 3-9, 3-10, 7-5, and 7-9. In both projects, additional land will be impacted by roads and rights-of-way for pipelines and power-lines.

[148] See Table 3-2, which shows that the net volume of make-up water (both fresh and saline) required to produce 1 m^3 of oil with in situ operations varies from almost zero (using THAI technology) to over 4 m^3 at Shell’s pilot CSS project at Peace River.

[149] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 28, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[150] Imperial Oil’s first pilot project in the Cold Lake area started near Ethel Lake in the 1960s, but the first commercial project was approved in 1983. Shell started operations in the Peace River area 25 years ago, using a variant of the CSS process referred to as the “radial soak” method. This has a vertical well with four horizontal arms that extend into the bitumen.

[151] The ultimate recovery rate with CSS is expected to be 20–35%, compared to 40–70% for SAGD. Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 28–29, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

replace water lost in the formation and treatment process. It may be less than 10%, or may be much higher (see Table 3-1, which gives details for individual companies).[152]

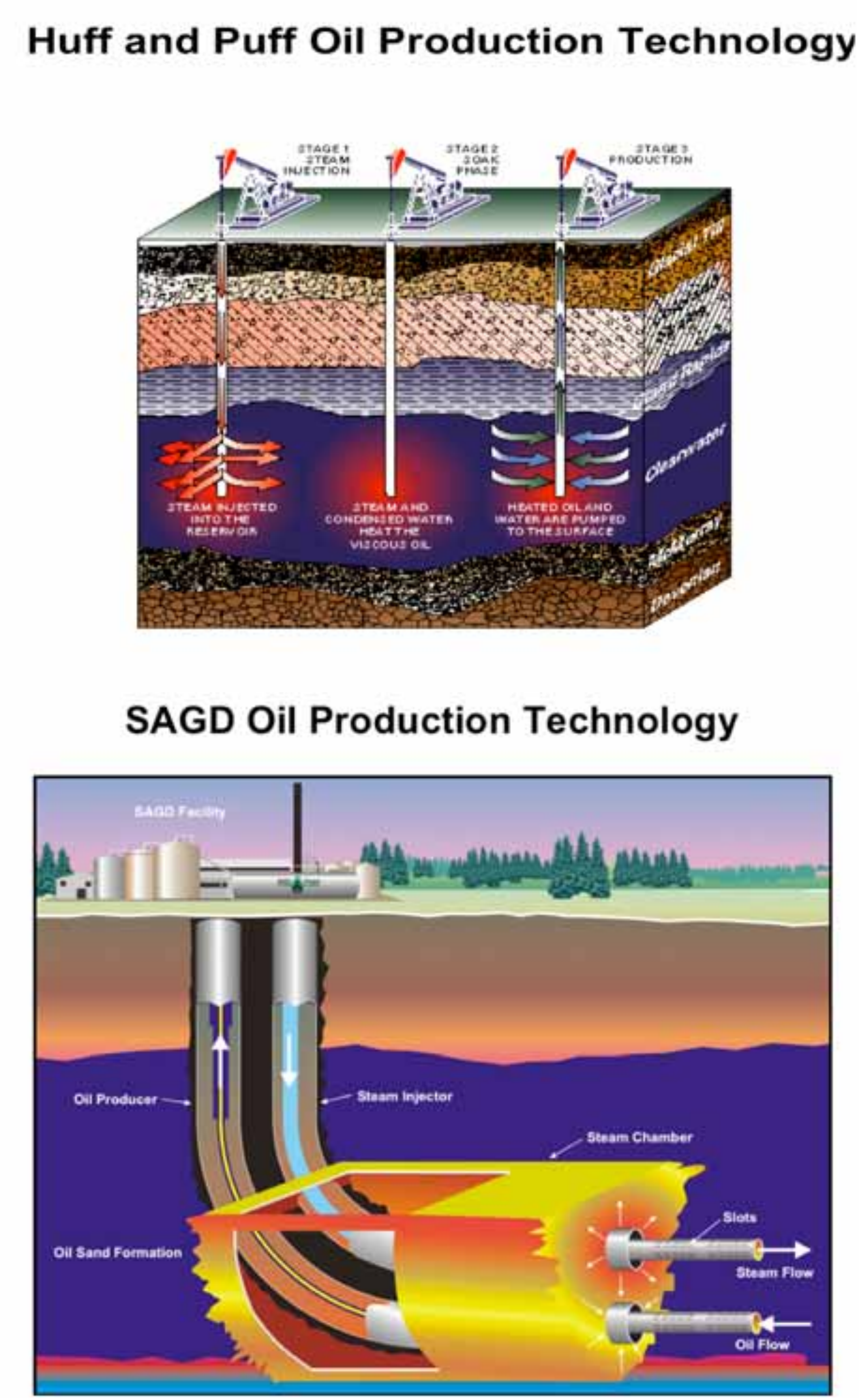

Figure 2-3 CSS and in situ recovery

Source: EnCana, with permission

[152] Isaacs, Eddy. 2005. *Canadian Oil Sands: Development and Future Outlook.* Alberta Energy Research Institute, http://www.aeri.ab.ca/sec/new_res/docs/oil_sands_dev_outlook_Isaacs_050214.pdf

2.3.2.2 Steam-assisted gravity drainage

Following more than a decade of research by the government-led Alberta Oil Sands Technology and Research Authority (AOSTRA) and the oil industry, the steam-assisted gravity drainage (SAGD) process was developed. Various factors will determine whether a company uses CSS or SAGD. SAGD can be used to extract oil in areas where mining is not possible but where the bitumen is not deep enough for high-pressure cyclical steam techniques to work.[153]In the SAGD process, steam is continuously injected underground through one set of pipes and the heated, fluidized bitumen and water (from the condensed steam) are collected and pumped to the surface through a lower, parallel set of pipes (see Figure 2-3, lower portion).[154] The oil is recovered and, as with the CSS process, the produced water is de-oiled and treated so that it can be reused in the steam generator. The commercial development of the SAGD process has led to a rapid increase in the number of oil sands projects and in the associated demand for water.

Several wells are drilled from a single well pad, and a project can have many pads over an extensive area. Devon's Jackfish project, for example, has a lease of approximately 12 sections (3,100 ha), on which it will have approximately 160 wells on 25 pads.[155] This is one of the smaller projects. Petro-Canada's Meadow Creek project will have 60–75 well pairs to produce twice as much bitumen as the Jackfish project, but the lease area is much larger (58 sections or 15,000 ha).[156]

Several cubic metres of water, in the form of steam, are needed to produce one cubic metre of bitumen. The actual steam-to-oil ratio in high-quality SAGD reservoirs is 2.5:1, compared to between 3:1 and 4:1 for CSS reservoirs. As indicated above, this produced water can be recycled.[157] Thus the net water requirement to produce a cubic metre of oil with in situ production may be as little as 0.2 m^3, depending on how much is recycled (see Table 3-1). Usually 2 or 3 m^3 of produced water are available for recycling for each cubic metre of bitumen recovered.[158] Companies may use fresh or saline water to generate steam for the CSS and SAGD processes (see Table 2-5), but, since the salinity of the water must not be too high, they either mix saline and fresh water or treat saline water before using it.

2.3.2.3 Water treatment for in situ recovery

Produced water must be treated before it can be used to generate steam for in situ oil recovery. Various processes are used to remove residual oil, silica (sand) and dissolved and suspended solids.[159] Each company will have a slightly different variation, but the standard process, using proven technology, involves the following stages:

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[153] Alberta Energy Research Institute. 2002. *Steam Assisted Gravity Drainage (SAGD),* http://www.aeri.ab.ca/sec/suc_sto/suc_sto_001_2.cfm

[154] Alberta Environment. 2004. *Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta,* http://www.waterforlife.gov.ab.ca/docs/water_oil_info_booklet.pdf

[155] Devon Energy. 2003. *Application for Approval of the Devon Jackfish Project,* Vol. 1, p. A1.

[156] Petro-Canada. 2001. *Application for Approval of the Meadow Creek Project*. Vol. 1, p. 3–4. See also footnote earlier in section 2.3.2 of this report, which compares the footprint of this Petro-Canada SAGD operation with an Imperial CSS operation.

[157] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 28–29, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[158] Peachey, Bruce. 2005. *Water and Energy Forum.* Petroleum Technology Alliance of Canada. Edmonton, Alberta. June 14, 2005.

[159] Marsalek, Jiri, Karl Schaefer, Kirsten Exall, Leah Brannen and Bijan Aidun. 2002. *Water Reuse and Recycling*. Canadian Council of Ministers of the Environment, Winnipeg, Manitoba. CCME Linking Water Science to Policy Workshop Series. Report No. 3, p. 24 provides a summary of pollutants and treatments, http://www.ccme.ca/initia tives/water.html?category_id=82

- De-oiling, to remove the residual bitumen. This may be done by passing the water first through a skim oil tank, then through a filtration unit.
- Water treatment, to remove the silica in the produced water. This involves either a warm or hot lime process, in which calcium and magnesium oxide are added to assist the removal of the silica. Apart from the use of heat to speed up the process, the procedure is similar to that used in municipal water treatment plants. Following treatment, the water is filtered and then treated to avoid build up of scale in the process equipment. (The treatment uses a weak acid cation process to remove any calcium and magnesium ions that might remain from the lime softeners, and replaces them with sodium ions, which don't cause scaling.)
- Disposal of waste products. Waste products from the treatment process, which include sludge and filter waste, may be disposed of in deep wells or, if some of the residual water is removed, put into a class II landfill.[160]

Once the water is treated, it is heated to convert it to steam. A "once-through" steam generator is normally used. This system produces 80% quality steam (80% vapour and 20% liquid), which is suitable for CSS.[161] The SAGD process requires 100% steam (with no liquid water) to avoid the build-up of small amounts of dissolved solids in the water. Thus the 20-25% residual water is removed, flashed to make steam again, condensed and fed back into the boiler feed water to make 100% steam. The small residue containing the dissolved solids is treated for reuse or disposed of in a deep disposal well.

2.3.2.4 Upgrading bitumen from in situ production

Upgrading of bitumen from mining operations is part of the recovery process. Bitumen recovered from CSS and SAGD operations is usually blended with a diluent (such as naptha or light hydrocarbons) and then piped to an upgrading facility elsewhere. At the present time, much of the CSS and SAGD production is exported to upgraders in the U.S. Midwest.[162] A small proportion is used for asphalt for road paving and roofing materials without being upgraded. In the future some bitumen will be diverted to new upgraders being constructed near Edmonton.[163]

Water is required for boiler feed water to generate steam and to replace evaporative losses in cooling towers, which are similar to those used for coal-fired power plants and petrochemical plants and refineries. Surface water is normally used, but the water is evaporated to the atmosphere rather than returned to the watershed. Some of the operations are integrated units, including co-generation and refining, which makes it difficult to estimate the proportion of water used purely for upgrading bitumen from in situ production. However, at Shell's Scotford Upgrader, which uses water from the North Saskatchewan River, approximately 0.69 m^3 of water is diverted for each cubic metre of oil produced. Some of the water is treated and released to the

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[160] Alberta Energy and Utilities Board. 1996. *Directive 058 Oilfield Waste Management Requirements for the Upstream Petroleum Industry*, section 15.7. A class II oilfield landfill can accept only non-hazardous solid oilfield waste, as described in this regulation, http://www.eub.gov.ab.ca/BBS/requirements/directives/default.htm

[161] Heins, William and Dan Peterson. 2005. Use of Evaporation for Heavy Oil Produced Water Treatment, *Journal of Canadian Petroleum Technology*, Jan. 2005, Vol. 44, No. 1, p. 26–30, http://www.deercreekenergy.com/presentations/tech_pres.html

[162] Bruce Peachey, personal communication. March 2006.

[163] For example, B.A. Energy Inc. 2004. Heartland Upgrader Application. Vol. 1, p. 2-1. The company plans to upgrade bitumen from the Cold Lake, Peace River, Wabasca and, eventually, Ft. McMurray areas.

river, so the net volume used is 0.38m^3 per cubic metre of oil produced.[164] This appears to be comparable with a new upgrader planned for the region.[165]

As noted earlier, the actual volume of water allocated or used for upgrading is included in the "industrial (oil, gas, petroleum)" category in the figures and tables in this report.

2.3.3 Conventional enhanced oil recovery

Large volumes of water are used for conventional EOR, primarily in older oil fields. Initially, oil from conventional wells may flow to the surface as a result of pressure or it may be pumped to the surface. As the oil is removed, the pressure in the formation gradually declines and some of the water in the formation will also be pumped to the surface with the oil. To maintain pressure in the reservoir, and enable more oil to be pumped out, it is necessary to inject water (or gas) into the formation. This "water flood" will increase the pressure and push more oil out of the rock. In the early stages of a water flood large volumes of water will be required to raise or maintain the reservoir pressure near original conditions, but as some of the water is pumped to the surface with the oil, it can be recycled. Since the additional make-up water required will be similar to the volume of oil removed, the total new water required for EOR has been declining at the provincial level since 1973.[166] At the same time, the water–to-oil ratio has been increasing, as more water is injected and produced with each unit of oil. While in 2000 an average of 11.6 units of water were produced with every unit of oil, it is estimated that by 2003 the number of units had increased to 16.[167] This means that in 2003, the water to oil ratio from a conventional Alberta oil well was 16:1 (i.e., 16 m^3 water was used to produce 1 m^3 oil).[168] The produced water is mostly recycled by re-injection back to the zone of origin during the ongoing production of oil and eventually remains in the depleted reservoir.[169]

Without injection of water to maintain pressure only 20–25% of the oil in the formation is recovered.[170] Water floods can increase oil recovery by 5–20% over primary production.[171] They have been used in 4–5% of oil reservoirs in Alberta, which contain about 35% of the original oil in place.[172] However, even with enhanced recovery methods (using both water and sometimes

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[164] Randy Provencal, Shell Canada Limited, personal communication. March 2006. In 2005 Shell diverted 6,254,580m^3 water for the Scotford upgrader (75% of the licence limits), to produce 3,447,500 m^3 of oil (56,575,000 barrels). See also, Scotford Upgrader Project Application. 1998. Vol. 1, p.i. and p. 4-1 for initial project design figures.

[165] North West Upgrading Inc. 2006. North West Upgrader Project Integrated Application for Approval. Vol. 1, p. B-1 and B-36. The project will upgrade 23,850 m^3/day (equivalent to 8,705,000 m^3/yr) crude bitumen when all three phases are operating in 2015. This is estimated to require 6,570,000 m^3/yr water, which will be withdrawn from the North Saskatchewan River. The gross water use will be approximately 0.75 m^3 per 1 m^3 bitumen upgraded, but it is expected that this figure will be reduced through treatment, recycle and release, and use of surface water runoff. Doug Bertsch, North West Upgrading Inc., personal communication, March 2006.

[166] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report*, p. 13, *http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf*

[167] Blaine Hawkins, Alberta Research Council, personal communication, September 2005. This updates information in slide 3 of Blaine Hawkins and Ashok Singhal. 2004. *Enhanced Oil Recovery Water Usage.* Alberta Research Council. Presentation to the Advisory Committee on Water Use Practice and Policy, March 2004, http://www.waterforlife.gov.ab.ca/html/technical_reports.html

[168] Hum, Florence, Peter Tsang, Thomas Harding and Apostolos Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy. University of Calgary, p. 4.

[169] This is not the case for SAGD; see the voidage issue in section 3.3.1.

[170] Peachey, Bruce. 2005. *Water and Energy Forum.* Petroleum Technology Alliance Canada. Edmonton, Alberta. June 14, 2005.

[171] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet*, p. 11; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[172] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet*, p. 10; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

various gases to maintain reservoir pressures) only 30–35% of conventional oil is currently being recovered.[173] There is thus still potential for more enhanced recovery of conventional oil in Alberta.

The water used for enhanced recovery may be saline or fresh (surface water or non-saline groundwater). As mentioned in section 2.1, Alberta Environment introduced a policy that required companies to look for alternatives to fresh groundwater for EOR in the agricultural (White Zone) area of the province.[174] After the policy was introduced in 1991, the volume of saline water used in the White Zone increased rapidly, but remained fairly low in the forested areas of the province (Green Zone), which were not affected by this policy.[175] The distribution of old and new EOR pools also influenced the trend as Alberta Environment only requested a review of alternatives for new applications. The new Alberta Environment t *Water Conservation and Allocation Guideline for Oilfield Injection* requires companies to look for alternatives to fresh water throughout the province, although the requirements are be most stringent in water-short areas.[176]

2.3.3.1 Drilling and fracturing wells

Water is a major constituent of drilling mud, which is the fluid circulated when drilling a well to cool the drill bit, remove the cuttings and maintain pressure in the well. The EUB requires that, in compliance with the *Water Act*, non-toxic fluids be used when drilling and completing the top of the well to protect shallow aquifers. Although the volume of water used to drill a well is relatively small compared with other oilfield uses, it may be a concern where local water supplies are limited. To some extent the volume of water required depends on the depth of the well and the formation. Approximately 100 m^3 is required to drill a shallow well.

Water may also be a constituent of "fracing" fluids. Fracing (or fracturing) a well is carried out by pumping special fluids into a well at high pressure to open up the formation, enabling the oil to flow more freely to the well. It is important to undertake shallow fracturing in such a way that impacts to fresh water aquifers do not occur.[177,178]

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[173] Peachey, Bruce. 2005. *Water and Energy Forum*. Petroleum Technology Alliance Canada. Edmonton, Alberta. June 14, 2005.

[174] Alberta Environment. 1990. *Ground Water Allocation for Oilfield Injection Announced*. News Release and Fact Sheet, March 27. This is reproduced as Appendix A in Alberta Environment. 2003. *Groundwater Evaluation Guidelines: Information Required When Submitting an Application under the Water Act*, http://www3.gov.ab.ca/env/water/Legislation/Guidelines/index.cfm The White Zone and Green Zone are sometimes referred to as the White Area and Green Area of the province; the terms are synonymous.

[175] Geowa Information Technologies, Ltd. 2003. *Water Use for Injection Purposes in Alberta.* Appendix, Figure 42: Total Saline Water Use by Zone, p. 84. Prepared for Alberta Environment, http://www.waterforlife.gov.ab.ca/docs/geowa_report.pdf and http://www.waterforlife.gov.ab.ca/docs/geowa_appendix.pdf For further discussion of the use of groundwater in the White and Green Zones, see Mary Griffiths and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources.* Drayton Valley, AB: Pembina Institute, p. 15, section 2.4 White vs. green areas in the province, http://www.pembina.org/publications_item.asp?id=154 In 2002, in the White Area the volume of fresh water used was estimated to be about 15% of the volume of saline water used. In the Green Area the volume of fresh water used was three times the volume of saline water used. Figures are derived from Canadian Association of Petroleum Producers. 2002. *Use of Water by Alberta's Upstream Oil and Gas Industry*, p. 5-10, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=56487 The CAPP study, which predates the Geowa report, separated the EUB data into the White and Green Areas of the province, based on the location of the wells.

[176] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection*, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[177] Alberta Energy and Utilities Board. 2006. *EUB Directive 027: Shallow Fracturing Operations*, http://www.eub.ca/docs/documents/directives/Directive027.pdf This topic will be further investigated by the technical review committee announced in the directive.

[178] It is not well appreciated by the industry that fracturing occasionally "runs away" or becomes an earthquake. The stresses have to be right for this to happen but stresses may have been the cause of an earthquake in the 1950s near Snipe Lake, Alberta. In the United States the Denver

2.4 The volume of water allocated and used

2.4.1 Oil and oil sands water allocations in perspective

Alberta is a large province, covering over 660,000 square kilometres,[179] with rivers flowing to the Arctic Ocean, Hudson's Bay and the Gulf of Mexico. Although Canada has many lakes and rivers, Alberta holds only 2.2 % of the country's fresh water.[180] The seven main river basins, shown in Figure 2-4, have varying characteristics, from the water-short South Saskatchewan and Milk River basins in the south, to the high-volume Peace River that drains via the Slave River to the Arctic.

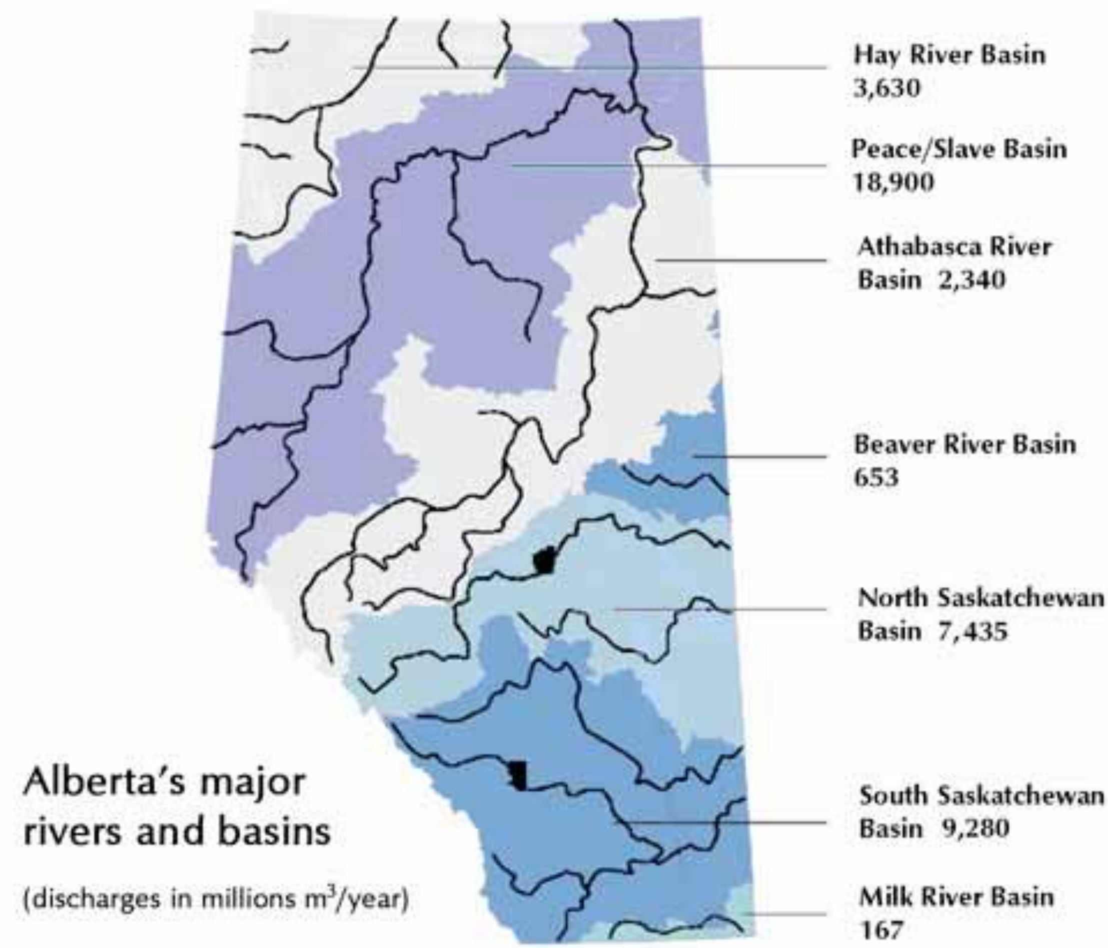

Figure 2-4 Major river basins in Alberta

Map source: Alberta Environment, with permission. Modified.

Arsenal Well in Colorado is the classic example of an injection-induced earthquake. Edo Nyland, Professor Emeritus, Physics, University of Alberta, personal communication, February 2006.

[179] Alberta is almost as large as Texas and considerably larger than France.

[180] Alberta Environment. 2002. *Water for Life: Facts and Information on Water in Alberta,* p. 3, http://www.waterforlife.gov.ab.ca/docs/infobook.pdf

As mentioned in section 1.4, over 7% of total water allocations in Alberta in 2004 were for the production of oil and gas. As Figure 2-5 shows, 1.9 % of all allocations were for oilfield injection. This is the water required for conventional EOR; that is, water flooding in conventional oil wells and the in situ extraction of bitumen (which is mainly through the injection of steam). A larger volume, 5.3 % of all allocations, was for industrial activities associated with oil, gas and petroleum. This includes water required for oil sands mining and upgrading, as well as for other refining purposes. A further category, water for drilling wells, received about 0.1 % of total allocations.[181]

Figure 2-5 gives the combined allocation for surface water and groundwater. Approximately 97% of the 9,726 million m^3 water allocated in the province in 2004 was surface water, with the remaining 3% (283 million m^3) coming from groundwater. In 2004, over 37% of all groundwater allocations in Alberta were for oil and gas production (Figure 2-6). Eighteen percent of the total groundwater allocation is for injection (i.e., for oil recovery, including conventional EOR and the in situ recovery of bitumen), while 19% is for industrial purposes relating to oil, gas and petroleum. Figure 2-6 does not show any allocation for household uses of groundwater at farms and individual residences in rural Alberta. This use of groundwater comprises a significant proportion of all groundwater use (estimated at 50% of the total), but is not included in this chart because a licence is not required for household water use.

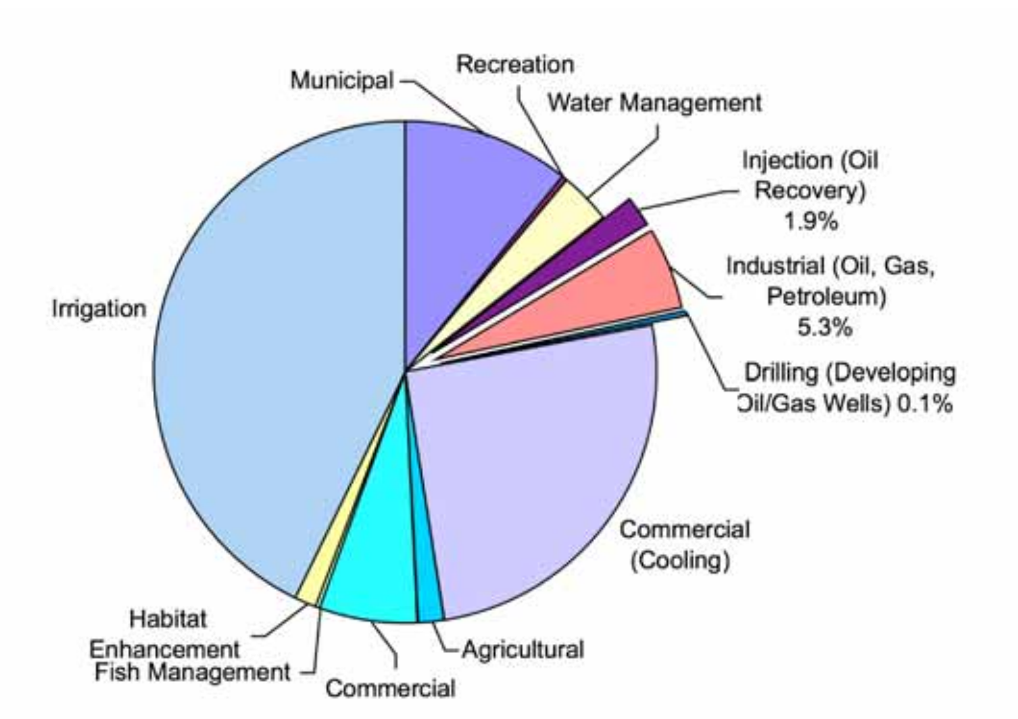

Figure 2-5 Total (surface and groundwater) allocations in Alberta, 2004

Data source: Alberta Environment

[181] Information supplied by Alberta Environment. Water for drilling does not require a licence from Alberta Environment in the Green Zone, as the forested area of the province is described, but companies are required to obtain approval from Alberta Sustainable Resource Development, which manages public lands.

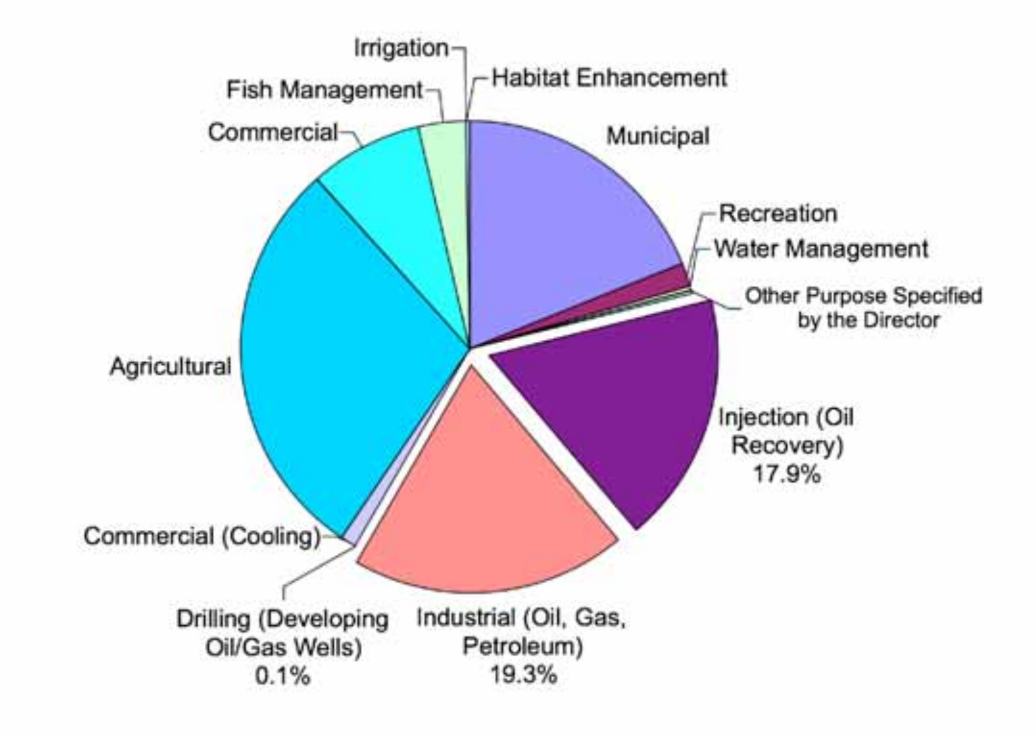

Figure 2-6 Total groundwater allocations in Alberta, 2004

Data source: Alberta Environment

Two points should be remembered when comparing the proportion of water allocated to different sectors:

- The figures are for allocation. Actual use is often much less than the volume allocated.
- The proportion of water that returns to the watershed varies, depending on the use. Thus, much of the water used for municipal purposes returns, after treatment, to the rivers. Some of the water used for cooling industrial plants will evaporate, as will some of the water used for irrigation. Water used for EOR remains deep underground and does not return to the watershed (although the oil will create water vapour when burned). Some water used for bitumen mining must be retained in tailings ponds, since it is too contaminated to discharge.

There is considerable variation between the river basins in the volume of water allocated for oilfield injection. The largest volume of surface water for enhanced conventional EOR and the in situ recovery of bitumen is allocated in the North Saskatchewan River basin; the largest fresh groundwater allocation is in the Athabasca basin (see Figure 2-7). When groundwater and surface water allocations for conventional EOR and in situ recovery are combined, the Athabasca River basin leads, with 55 million m^3 being allocated in 2005. This volume appears small compared to that allocated for oil sands mining and upgrading in the Athabasca River basin, where 282 million m^3 of surface water (and 4 million m^3 of fresh groundwater) were allocated for industrial purposes (oil, gas, petroleum). This category includes all the water required for oil sands mining and upgrading (Figure 2-8).

The volume of water allocated in the Athabasca Basin for mining and upgrading is almost ten times the volume allocated in the industrial (oil, gas, petroleum) category in any other river basin. In the South Saskatchewan River basin the industrial (oil, gas petroleum) allocation is 31 million m^3, whereas in the North Saskatchewan River Basin it is 25 million m^3. Much of the allocation from the South Saskatchewan is from its tributary the Red Deer River, for use in the petrochemical industry in the Joffre–Prentiss area; some is from the Bow River and there is one allocation from the Medicine River. Most of the water diverted from the North Saskatchewan River in this industrial category is for upgrading and refining in the Edmonton–Ft. Saskatchewan area, with the Husky Oil Refinery on the Alberta–Saskatchewan border the only other major licence holder.

It is difficult to grasp the huge volume of water allocated in the Athabasca River basin, or the scale of the increases expected in the future. In early 2005 the total volume of surface water and fresh groundwater allocated for industrial (oil, gas, petroleum) purposes and for oilfield injection—341 million m^3—was almost twice the total allocation for municipal uses in the entire North Saskatchewan River basin (186 million m^3); that allocation includes all the water required for municipal purposes in the Greater Edmonton area, with a population of nearly one million people. Two new projects (CNRL's Horizon mine and Shell's Jackpine mine) are being granted a further 143 million m^3 of water per year from the Athabasca River, which is not included in Figure 2-8. These allocations bring the current total allocation to 484 million m^3/year.[182]

In the Athabasca River basin in early 2005 53% of the combined total of surface water and fresh groundwater allocations were for oilfield injection or industrial (oil, gas, petroleum) purposes, far higher than in any other river basin. Looking only at surface water in the Athabasca River basin, existing and approved water licences for oil sands mines represent almost two-thirds of surface water allocations in the lower Athabasca River reach, a figure that will increase even further when the planned oil sands mines proceed (see Table 2-3). Second was the Beaver River basin, where over 28% of all allocations were for oilfield injection, much of this being for in situ recovery of bitumen in that area.

[182] This figure excludes allocations for the use of surface runoff, and so on, which are included in Table 2-3.

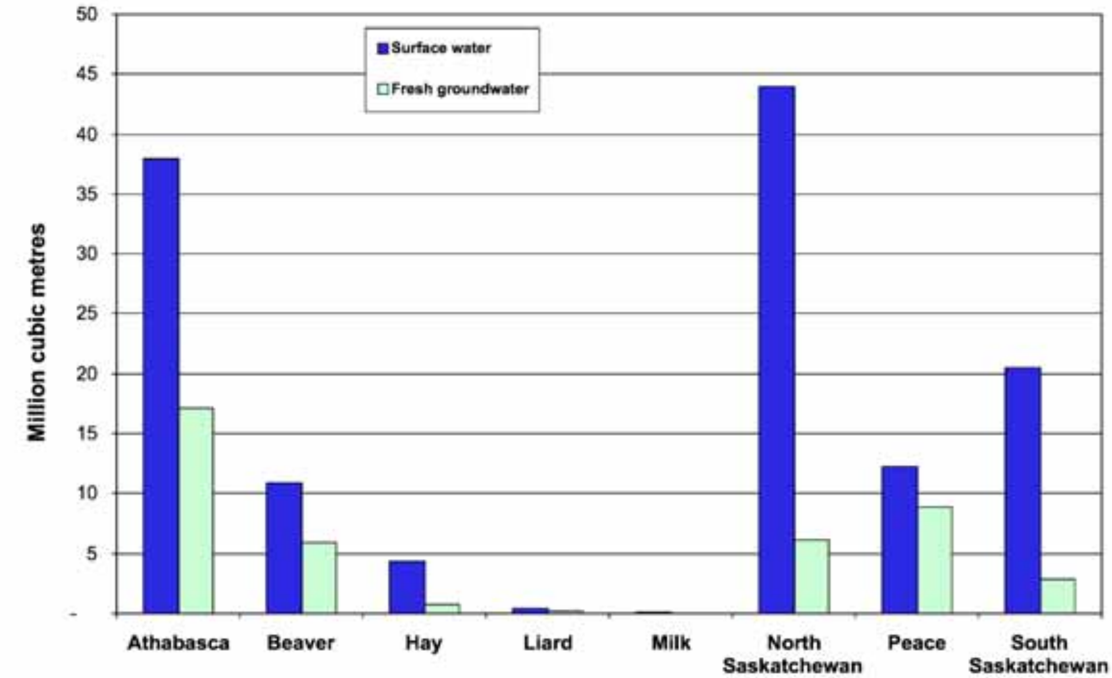

Figure 2-7 Surface water and fresh groundwater allocations for conventional EOR and for in situ bitumen recovery in major river basins in Alberta, 2005

Data source: Alberta Environment, personal communication[183]

[183] Data is for March 31, 2005. The Slave River Basin is omitted from this and subsequent figures, since there were no allocations for oil recovery in that basin.

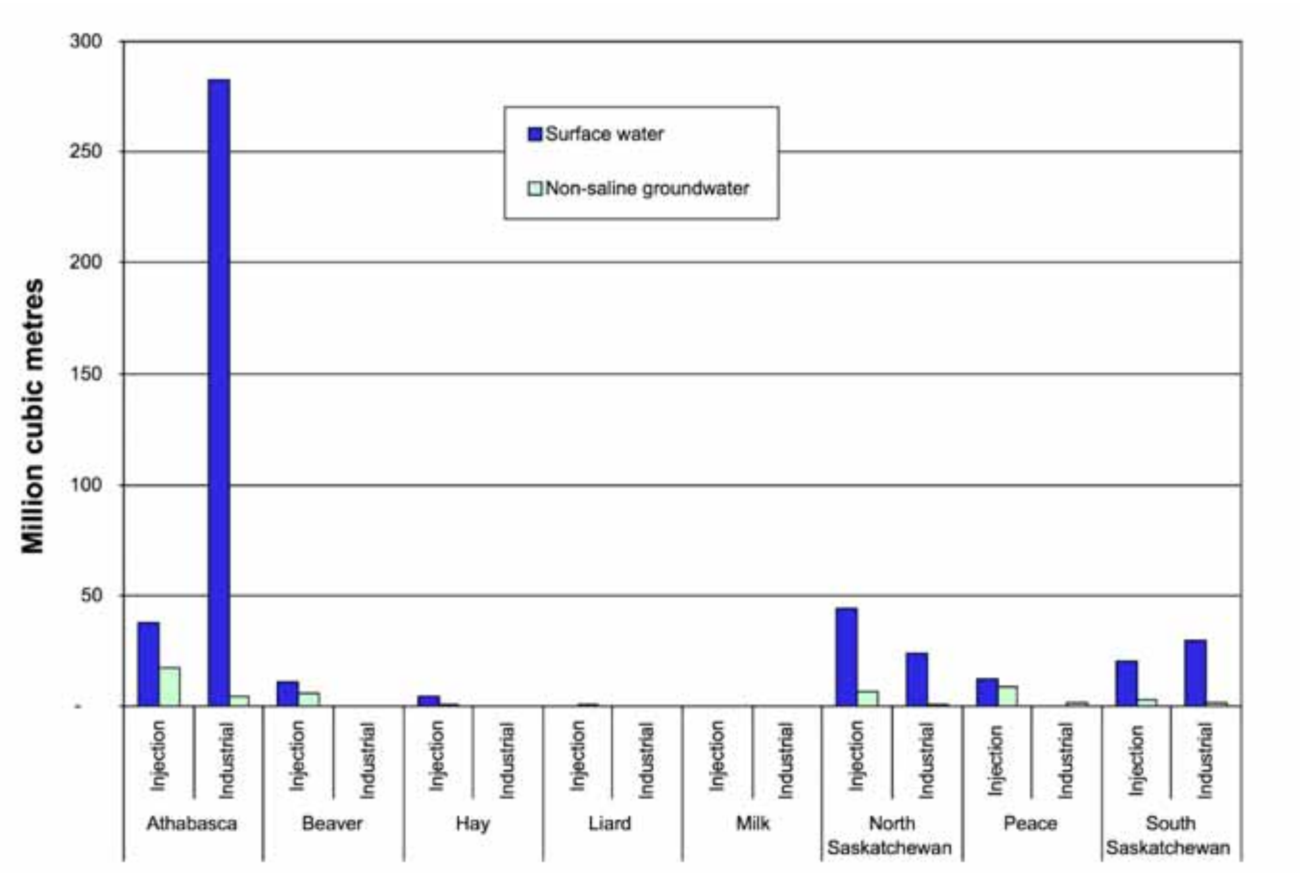

Figure 2-8 Surface water and fresh groundwater allocations for conventional EOR and in situ bitumen recovery and for industrial (oil, gas, petroleum) purposes in major river basins in Alberta, 2005

Data source: Alberta Environment, personal communication.[184] Note that the surface water industrial data for the Athabasca River Basin does not include recent allocations for the Shell Jackpine or CNRL Horizon projects, for which an additional 143 million m^3 of water has been allocated from the Athabasca River, making a total allocation of 425 million m^3 from the entire basin.

[184] Data is for March 31, 2005. The Slave River Basin is omitted since there were no allocations for oil recovery in that basin.

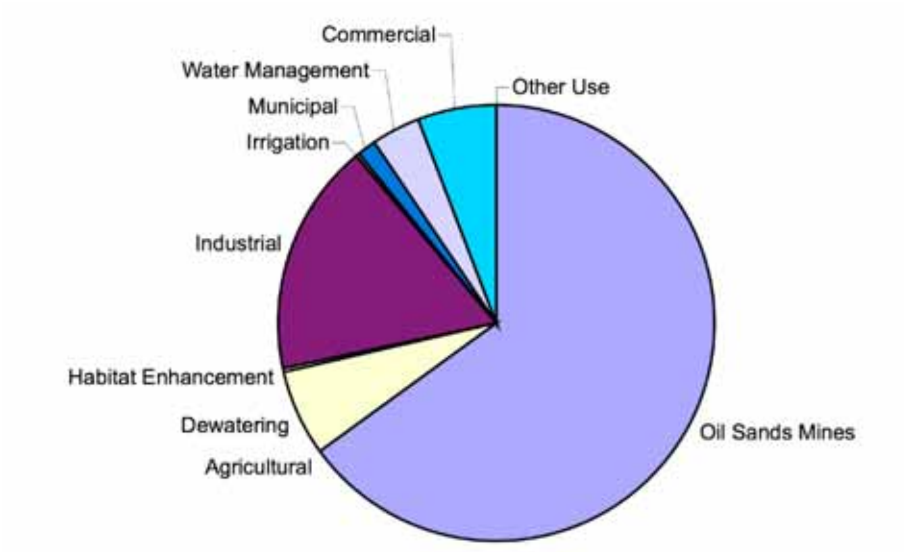

Figure 2-9 Licensed surface water allocations from the Athabasca River and its tributaries, 2005

Source: Golder Associates Ltd. 2005. *A compilation of information and data on water supply and demand in the lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group. Table 13.

2.4.2 Water use versus allocation

There may be a large difference between the volume of water allocated in a licence and the actual amount used.

In oil sands mining operations this difference is in part due to the past practice of granting water licences with allocations for the volume of water required for operation start-up, which is substantially greater than the volume required for ongoing operations. Of the 180 million m^3 of surface water allocated to the three oil sands mines currently operating, 55% of the cumulative allocation was actually used in 2004.[185] Figure 2-10 demonstrates the considerable difference between water allocation and use for Suncor, Syncrude and Albian Sands' oil sands mining operations, all of which are currently operating.

[185] The three companies currently operating oil sands mines used the following percentages of their licensed surface water allocation: Syncrude, 50%; Suncor, 78%; Albian Sands, 55%. Data sources respectively: Syncrude Canada Ltd. 2005. *Sustainability Report 2004,* p. 57; Suncor Energy Inc. 2005. *2005 Report on Sustainability,* p. 66; Shell Canada Ltd. 2005. *2004 Sustainable Development Report,* p. 25.

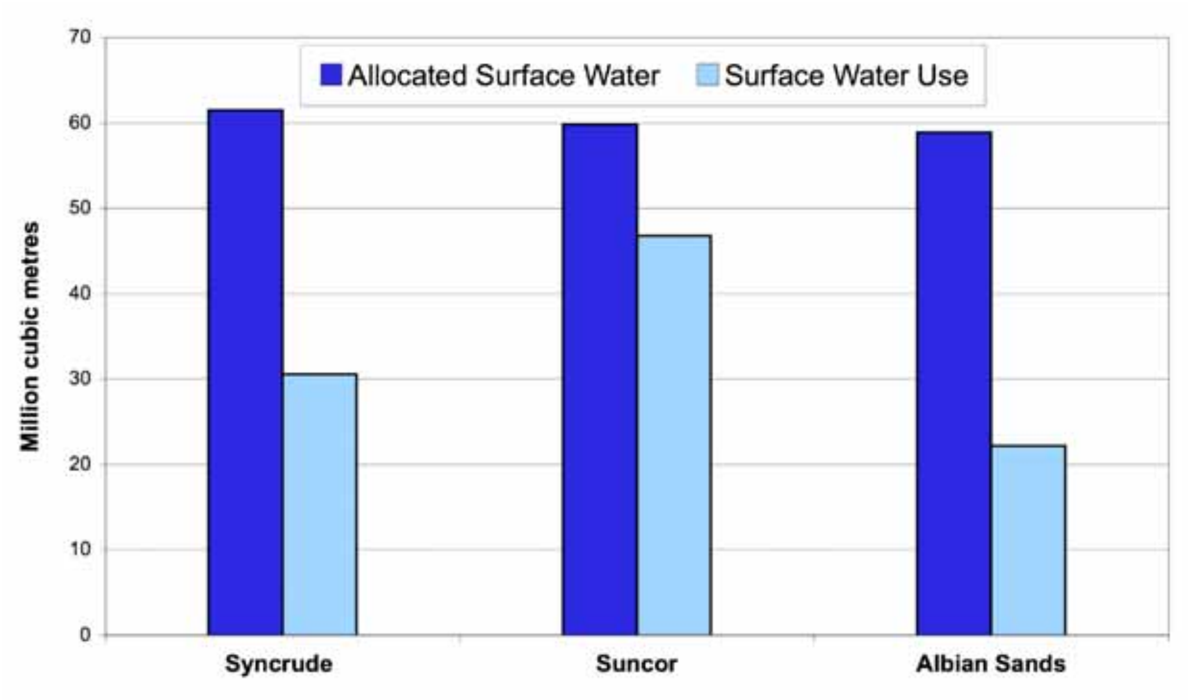

Figure 2-10 Surface water allocations vs. use at oil sands mining operations, 2004

Data sources: Syncrude Canada Ltd., 2005. *Sustainability Report 2004.* p. 57; Suncor Energy Inc. 2005. *2005 Report on Sustainability.* p. 66; Shell Canada Ltd. 2005. *2004 Sustainable Development Report.* p. 25.

To address this discrepancy and ensure that water allocations more closely reflect changes in operational water requirements over the life of an oil sands mining operation, Alberta Environment has begun issuing phased licences, such as the water licence issued for the CNRL's Horizon Mine, depicted in Figure 2-11.

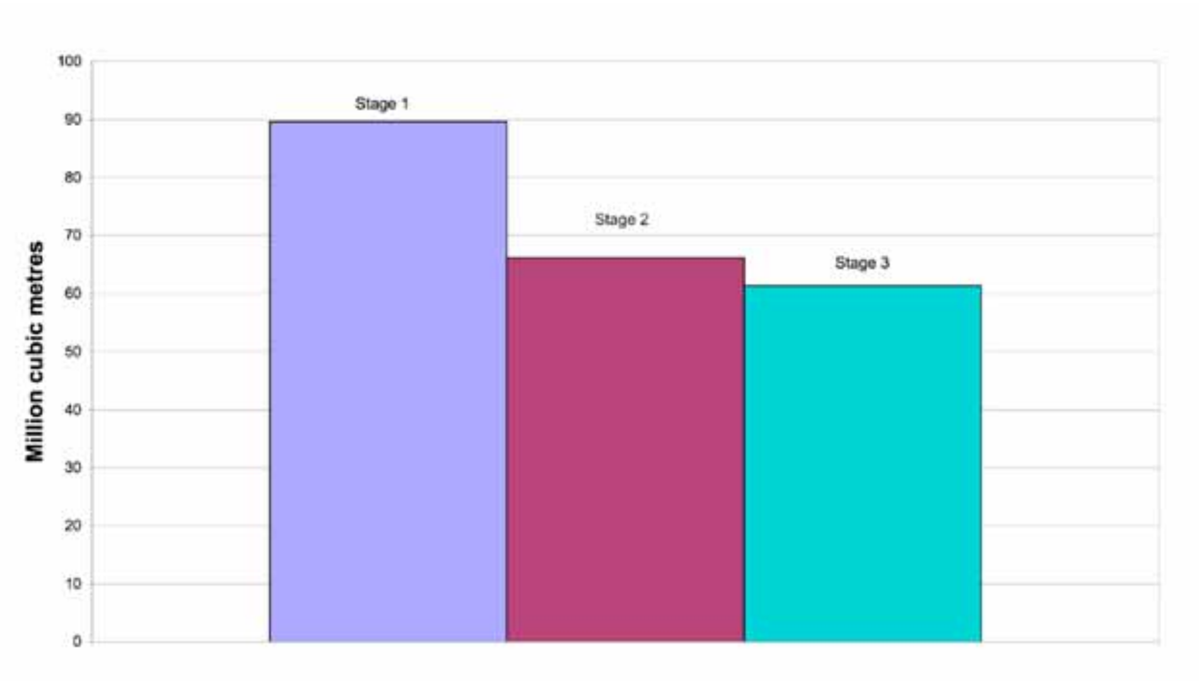

Figure 2-11 Staged water licences for CNRL's Horizon Mine Operation

This difference between the volume of water allocated and the actual amount used is also evident for conventional EOR and in situ bitumen recovery (see Figures 2-12 and 2-13).

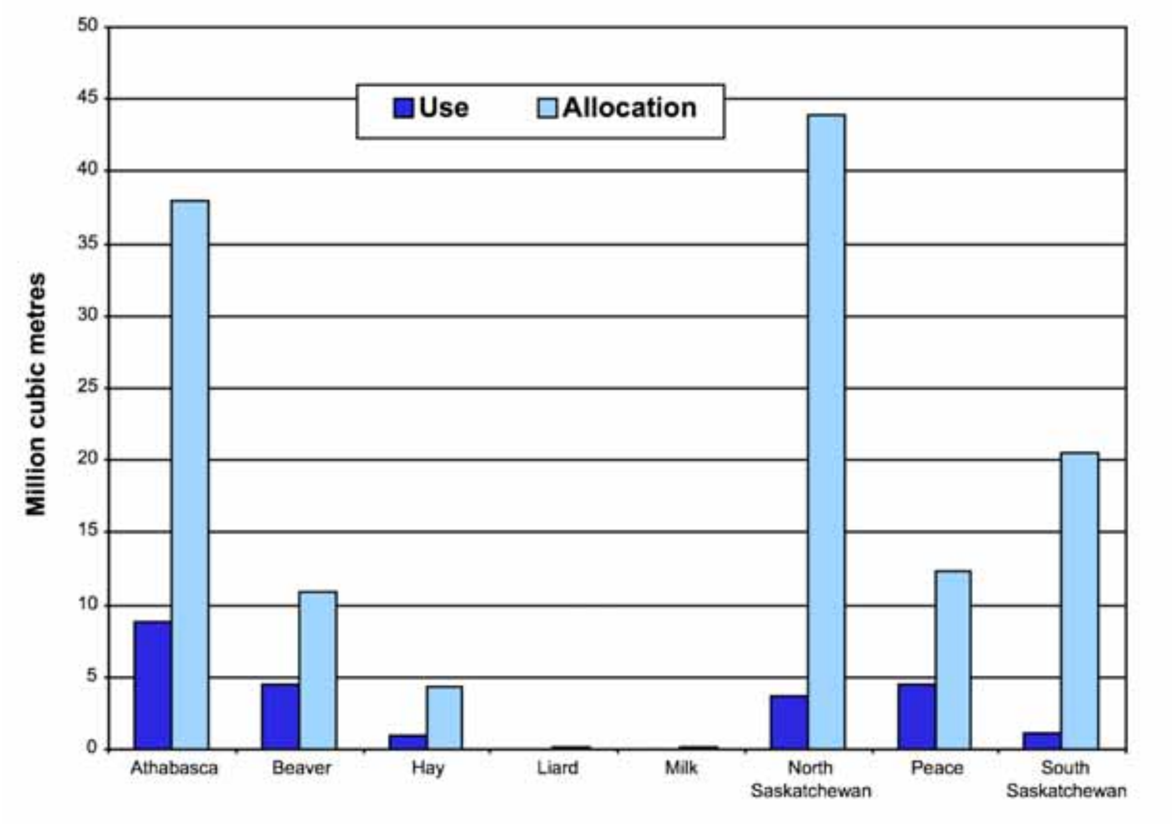

Figure 2-12 Surface water allocation and use for conventional EOR and in situ bitumen recovery in Alberta river basins, 2004

Data source: Alberta Environment, personal communication.

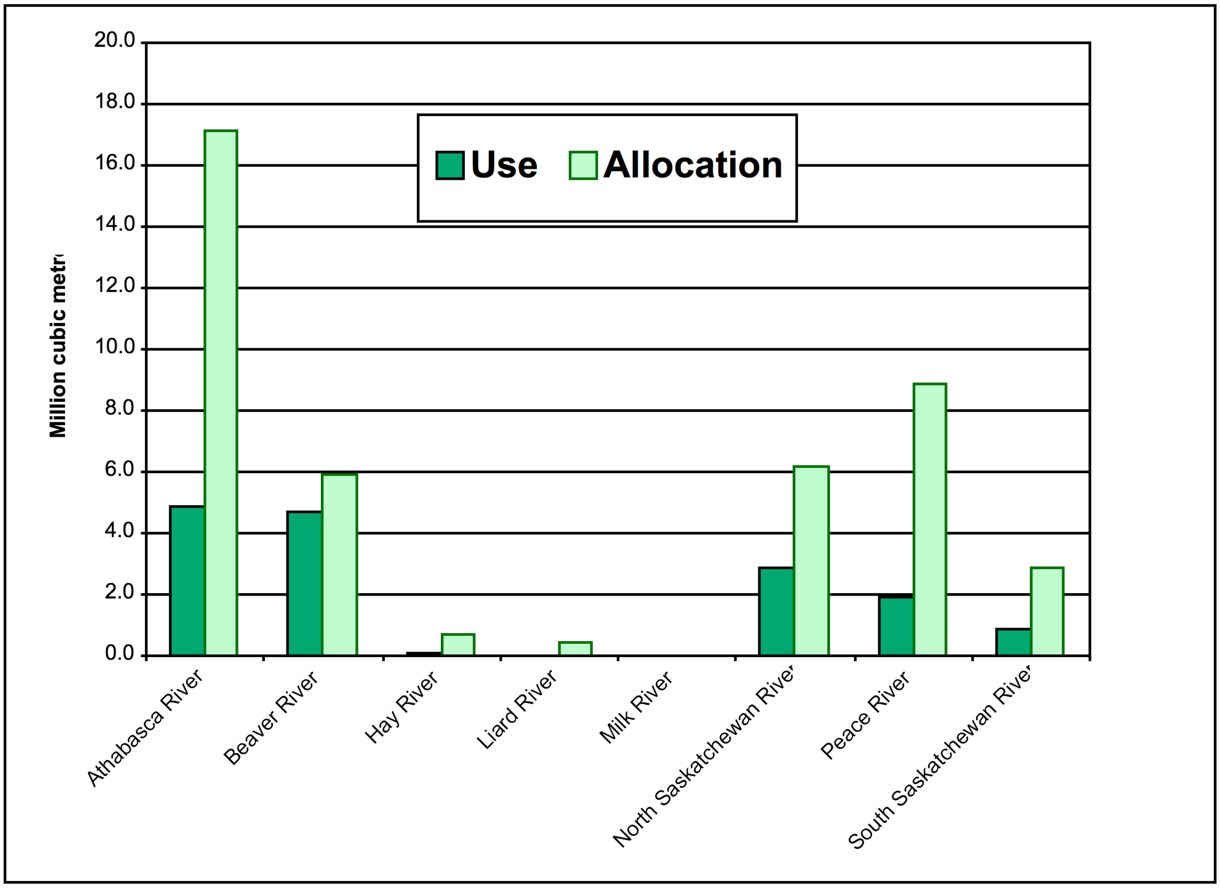

Figure 2-13 Groundwater allocation and use for conventional EOR and in situ bitumen recovery in Alberta river basins, 2004

Data source: Alberta Environment, personal communication.

In thermal recovery of in situ bitumen, more water is required initially to produce steam than for later production, since much of the water (from the condensed steam) is subsequently recycled.

Likewise, in conventional oil recovery, a large volume of water may be needed to build up pressure in a depleted reservoir, but the water that comes to the surface with the oil is often recycled, so the amount of new source water (or "make-up" water) declines.

Of the 277 million m^3 of water used for conventional EOR and in situ bitumen recovery in 2001, 83% was recycled water.[186] The balance consisted of make-up water, which came from surface rivers and lakes, shallow fresh groundwater or deeper saline groundwater.

The difference between allocation and use varies between river basins. In the Beaver River Basin, the use of groundwater is closest to the allocation, reflecting the level of activity in the Cold Lake area.

[186] Alberta Environment. 2004. *Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta,* p. 12, http://www.waterforlife.gov.ab.ca/docs/water_oil_info_booklet.pdf

2.4.3 Water use trends in oil and oil sands

2.4.3.1 Oil sands mining

2.4.3.1.1 Water use intensity

The intensity and nature of water use differs between operators for a number of reasons, making it complex to accurately compare operations and benchmark best practices for water management at oil sands mines. Different operators are able to draw varying volumes of water from various sources of water and use water in different ways, depending on the processes being used, the size and maturity of the development and the quality of the product being produced. Table 2-2 provides an example of the water use intensity at Syncrude Canada Ltd., the second longest operating oil sands mining facility.[187]

Table 2-2 Water use at Syncrude oil sands operation in 2004

	Syncrude[188]
Total synthetic crude production (million m^3)	13.9
Water withdrawn from the Athabasca River (million m^3)	30.6
Water withdrawn from the Athabasca River per cubic metre of synthetic crude (m^3)	2.21
Water recycled (million m^3)	228.4
Proportion of water from recycled sources (%)	88
Total water use (million m^3)	259

While Syncrude notes that it has made improvements in the intensity of its use of water from the Athabasca River, plans to increase production of synthetic crude will lead to net increases in water withdrawals.[189]

2.4.3.1.2 Current and future water use

There are four main sources of water for oil sands mining operations: water withdrawn from the Athabasca River, ground water (from the basal aquifer), surface runoff from the plant site, mine pits and tributaries, and connate water contained within the mined oil sands.[190] Oil sands mining operations that are already operating or have received government approval to operate are currently licensed to divert a total of 518 million m^3 of water (surface water, surface runoff and groundwater), 359 million m^3 of which is permitted to be diverted from the Athabasca River (Table 2-3).[191]

[187] Suncor and Syncrude began their mining operations in 1967 and 1977, respectively. Source: Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group. Table 12.

[188] All figures verified by Ron Pauls, Syncrude Canada, personal communication, January 12, 2006.

[189] Syncrude Canada Ltd. 2005. *Sustainability Report 2004,* p. 57.

[190] Note that muskeg drainage water is also used, however, as noted in section 2.3.1.1, Alberta Environment does not collect data from operators about the volume of drainage water retained and used.

[191] For comparison, the City of Edmonton diverted and treated 127 million m^3 in 2004, for a population of over 900,000. EPCOR. 2004. *Greater Edmonton Region,* http://www.epcor.ca/Communities/Alberta/Water+Partnerships/Edmonton/

Table 2-3 Water allocations for oil sands mining, 2005

Company (all mining projects, operating or licensed)	Licensed Allocation from the Athabasca River (thousand m^3)	Licensed Diversion from Groundwater Sources (thousand m^3)	Licensed Surface Water and Runoff Diversion (thousand m^3)	Total Water Diversion (thousand m^3)
Suncor	60,424	16,604	8,725	85,754
Syncrude	61,675	21,969	10,656	94,301
Albian	55,100	7,130	3,830	66,060
UTS Energy	39,270	6,665	6,847	52,782
CNRL	79,320	7,300	34,700	121,320
Shell	63,500	26,000	8,900	98,400
Total	**359,290**	**85,668**	**73,659**	**518,616**

Data source: Alberta Environment, *Water Act* licences for oil sands mining (water uses for processing, camps, etc.)

When considering planned oil sands mining projects that will seek water licences within the next two to three years, an additional 214 million m^3 of surface and groundwater will be required, increasing cumulative water requirements to an enormous 665 million m^3 (Figure 2-14), significantly more water than is consumed on an annual basis by the Greater Toronto Area.[192] This projection was based on information available in 2004, so projections that include oil sands mining projects disclosed in 2005 will be even higher.[193]

Oil sands mining operations produced 111,700 m^3/day of bitumen in 2004, a figure which the EUB expects to increase by 233% (to 260,000 m^3/d) by 2014. While it is difficult to predict the exact growth in the demand for water, is clear that growth in oil sands mining operations will contribute to greater water requirements in the future, exceeding those included in Table 2-3 and depicted in Figure 2-14.

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[192] In 2004, the City of Toronto used 1.43 million m^3 per day, for an annual total of approximately 522 million m^3. Source: Toronto Water. 2004 Annual Report. Available at http://www.toronto.ca/water/annual_report/pdf/annual_report_2004.pdf.

[193] Synenco Northern Lights (100,000 bpd), Deer Creek Joslyn Mine (100,000 bpd, potentially up to 200,000 bpd).

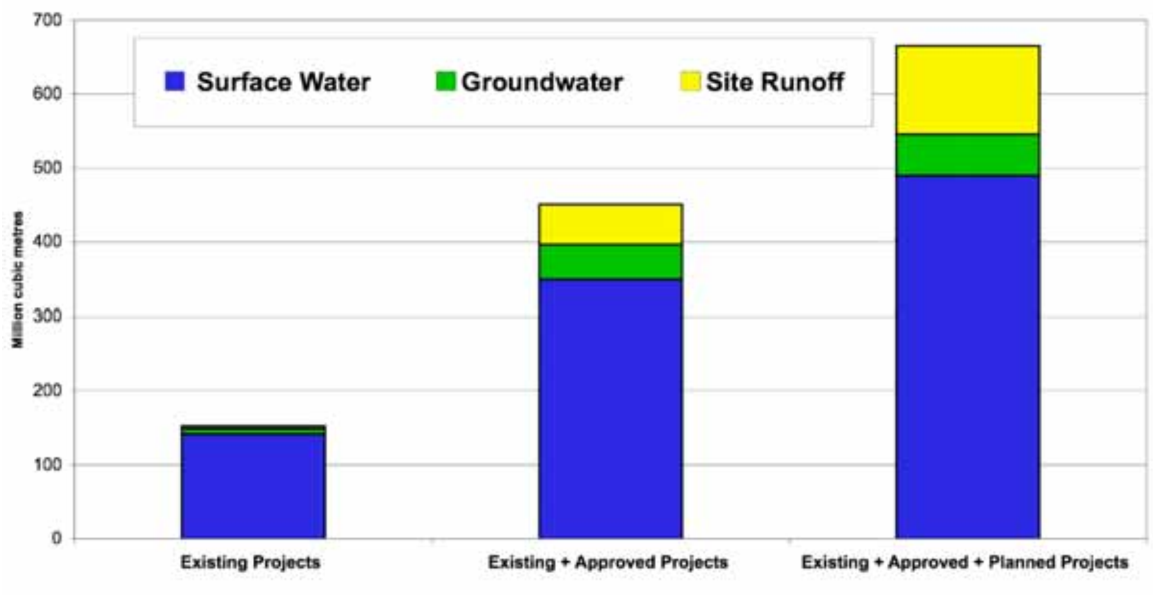

Figure 2-14 Cumulative water allocations for existing, approved and planned oil sands mining operations

Source: Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group. Table 13. & *Water Act* licences issued to oil sands mine operators.

Looking further into the future, withdrawals of water from the Athabasca River to fill EPLs created at the end of mining operations will also be substantial, with the planned cumulative withdrawal totalling 3.5 billion m^3. Based on current filling plans, peak withdrawal from the Athabasca River for EPL filling will be 302.7 million m^3 in 2041.[194]

2.4.3.2 In situ and conventional enhanced oil recovery

Although there are important differences between conventional EOR and the in situ recovery of bitumen, government statistics sometimes combine the data on water use for these two types of oilfield injection. The total volume of water allocated for these purposes in Alberta is increasing. While the volume of surface water used has decreased, between 2001 and 2004 the volume of fresh groundwater allocated and used increased (Table 2-4 and Figure 2-15). This increase is a concern, since the government's *Advisory Committee on Water Use Practice and Policy* was set up to reduce the use of fresh water for oilfield injection. Although the new policy was only introduced in 2006, the industry was aware of public and government concern about this use of fresh water.[195]

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[194] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group. Table 16. Converted cubic metres per second to annual total volume.

[195] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* http://www.waterforlife.gov.ab.ca/html/removed.html Alberta Environment is working on the implementation of these recommendations.

Table 2-4 Allocation and use of surface water and groundwater for conventional EOR and in situ bitumen recovery, 2001 and 2004

	Allocation (million m^3/year)		Used Volume (million m^3/year)		% Allocation Used	
	2001	2004	2001	2004	2001	2004
Total oilfield injection volumes	174.8	183.0	47.5	57.0	27	31
Fresh groundwater	43.5	50.8	10.2	13.9	23	27
Saline groundwater	N/A	N/A	10.4	17.9	N/A	N/A
Surface water	131.3	132.2	26.9	25.2	20	19

Source: EUB, personal communication, 2005.

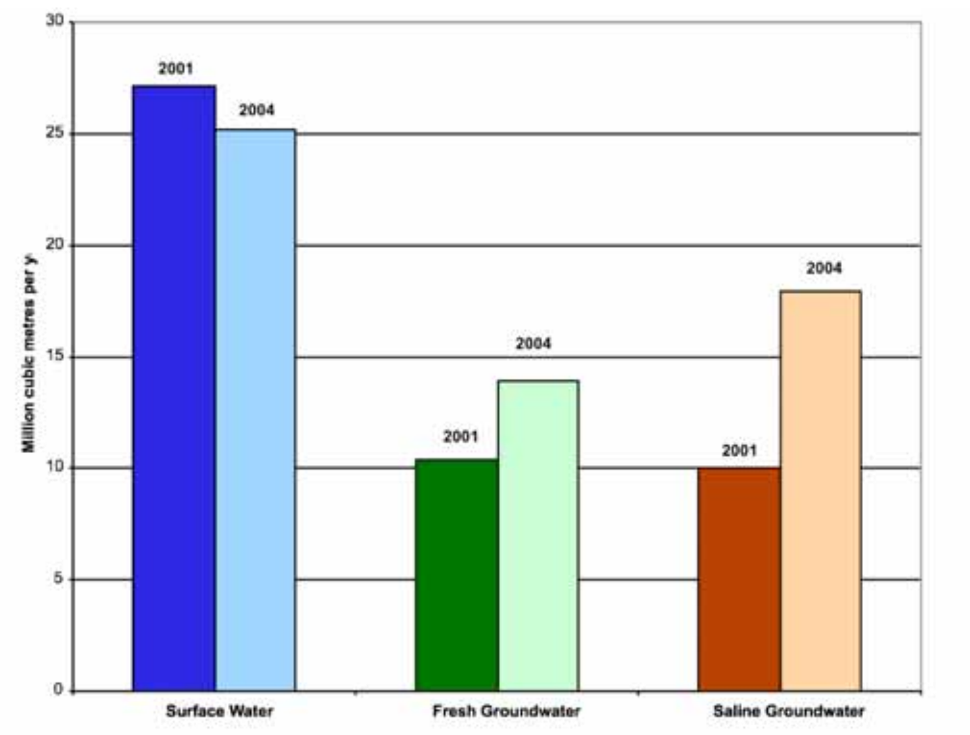

Figure 2-15 Total source water use (fresh and saline) for conventional EOR and in situ recovery of bitumen in Alberta, 2001 and 2004

Data source: EUB, as for Table 2-4.

Figure 2-15 shows the actual volume of water used for conventional EOR and in situ recovery combined. However, as can be seen in Figures 2-16 to 2-18, the trend for conventional injection is quite different from that for in situ recovery. The total use of water (fresh and saline) for conventional EOR is declining, while for in situ recovery is increasing (Figure 2-16).[196]

[196] The data for in situ projects in this figure includes not only water used for thermal projects, but also water for a few projects that use cold water for enhanced in situ recovery of bitumen (EnCana and CNRL at their Brintnell operations).

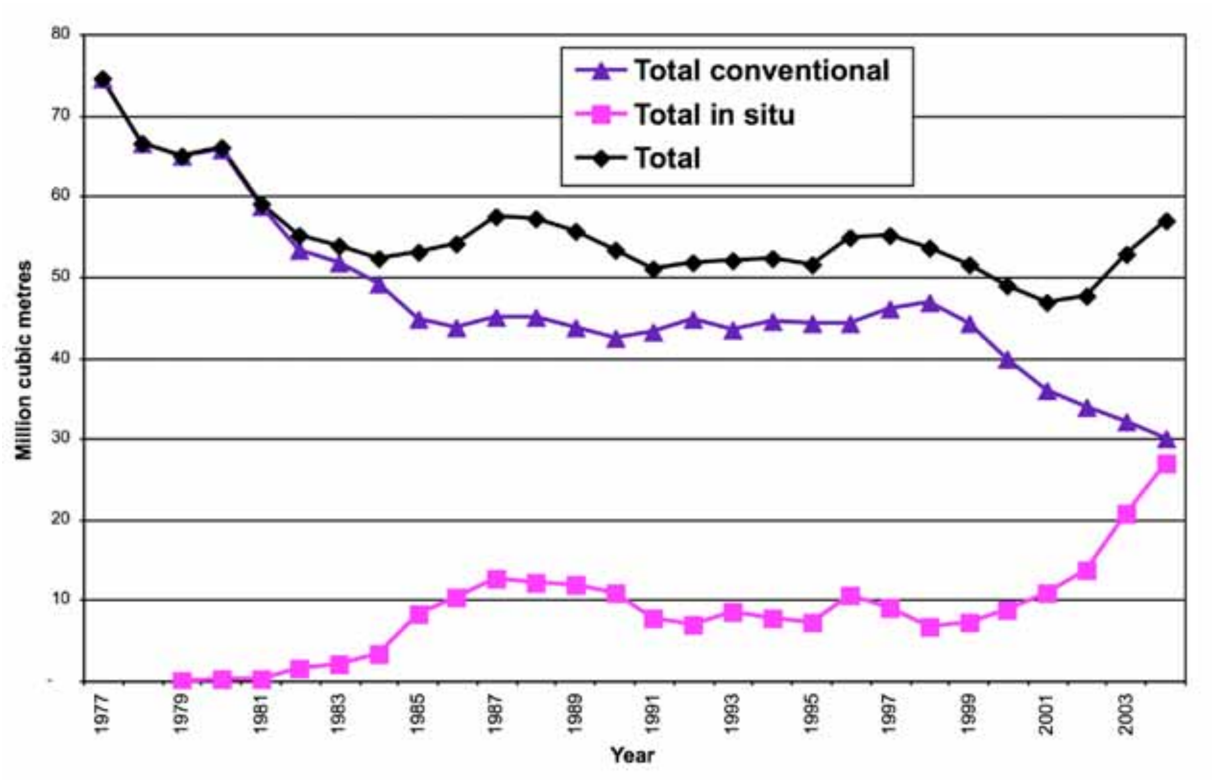

Figure 2-16 Total source water use for conventional EOR and in situ bitumen recovery in Alberta, 1977–2004

Data source: EUB, personal communication

The volume of fresh surface water and groundwater used for conventional EOR has been declining (Figure 2-17). Since enhanced recovery from conventional oil wells has been taking place for decades, and since the total volume of oil produced from these wells is declining, the volume of make-up water used in the province has also been declining. Not only is the total volume required less than half of that used in the early 1970s, there has been a gradual increase in the use of saline groundwater.[197] The volume of water needed for conventional oil recovery is likely to continue to decline with fewer new large oil pools being discovered, since the remaining established reserves of conventional oil are relatively small. In 2004 they were estimated at 249 million m^3, compared with an annual production of 35 million m^3.[198] Nevertheless, the volumes used are a concern, especially in water-short areas.

[197] Alberta Environment. 2004. *Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta,* charts on p. 14 and 15, http://www.waterforlife.gov.ab.ca/docs/water_oil_info_booklet.pdf

[198] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 3, http://www.eub.gov.ab.ca/bbs/default.htm

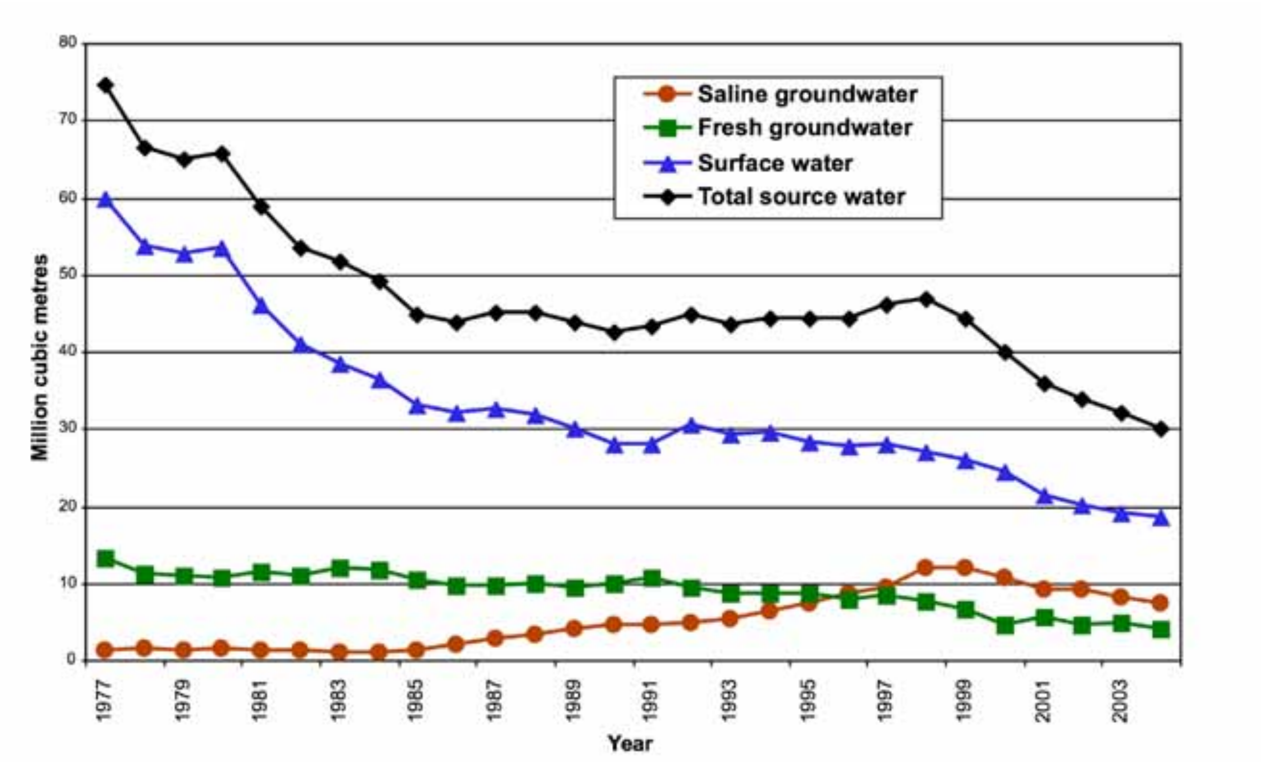

Figure 2-17 Total fresh and saline groundwater and surface water use for conventional EOR in Alberta, 1977–2004

Data source: EUB, personal communication

The increasing use of water for in situ bitumen recovery gives the greatest cause for concern. The use of fresh groundwater and surface water for in situ recovery has increased rapidly since 2000 (see Figure 2-18). There has also been a rapid increase in the use of saline water, but most of the saline water used since 2001 has been for primary recovery of bitumen, using cold water flood.[199]

[199] In 2003 3 million m^3 of saline water was used for cold primary recovery of bitumen and in 2004 this was 8.9 million m^3, or 83% of the total saline water use.

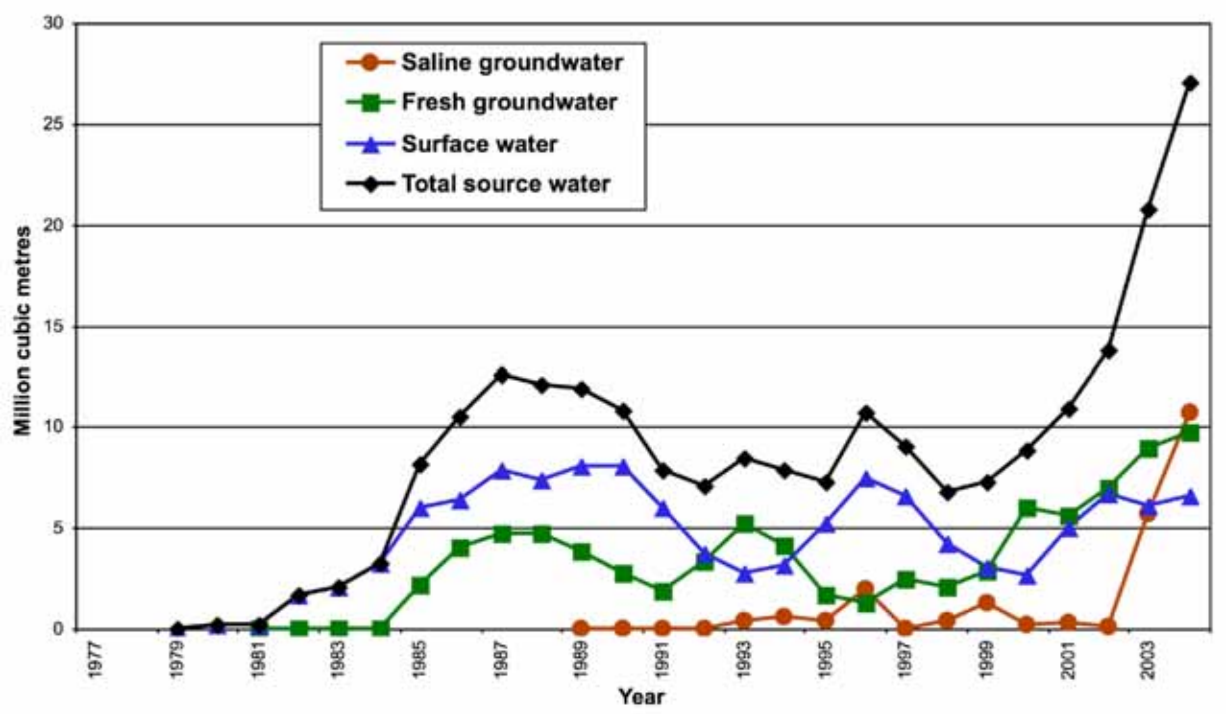

Figure 2-18 Total fresh and saline groundwater and surface water use for in situ bitumen recovery in Alberta, 1977–2004

Data source: EUB, personal communication[200]

In early 2003 Alberta Environment attempted to predict the increase in the demand for water for in situ recovery; it used data for 2001 and earlier, as well as figures for expected use taken from EIAs. The predicted use is shown in Figure 2-19. However, the actual demand for water is growing much more rapidly than this. In 2004 the use of fresh water for thermal enhanced recovery of bitumen (Figure 2-18) was three times greater than the forecast amount shown in Figure 2-19 (16 million m^3/year for surface water and fresh groundwater combined, compared with the prediction of 5.4 million m^3/year).[201] The use of saline water was double the volume predicted, but as noted above much of this was for cold recovery of bitumen.[202] A comparison of the predicted and actual use of water in 2004 is shown graphically in Figure 2-20.

This is clearly contrary to the government's intention to reduce the use of fresh water for oil recovery.[203] The forecasts in Figure 2-19 should thus be regarded as extremely conservative; they will be exceeded if the pace of development continues without any technological improvements to reduce the use of water. At the time of writing, Alberta Environment is revising its water use data for 2002–2005 and will use that to make new predictions, based on the accelerated increase in water use. It will be important to monitor results to determine whether the Alberta

[200] The saline volumes in 2003 and 2004 in this figure include cold water injection for bitumen recovery.

[201] The volume of fresh water in Figure 19 is shown by the difference between the saline groundwater use and the total source water use.

[202] Much of the increase in the use of saline water is for projects doing cold recovery of bitumen, which started in 2001 but grew rapidly in 2003 and 2004, according to EUB figures.

[203] As shown by the mandate of the *Advisory Committee on Water Use Practice and Policy*.

Environment's *Water Conservation and Allocation Policy for Oilfield Injection*[204] and the associated guideline will change this trend.

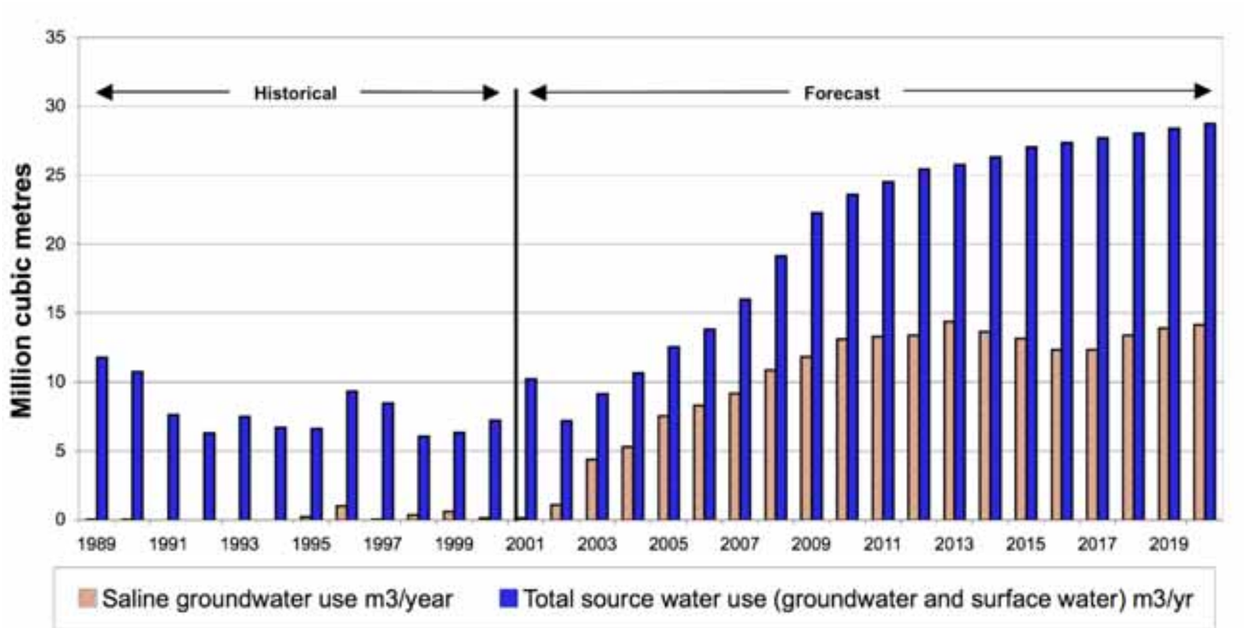

Figure 2-19 Outdated estimation of future water demand for in situ (thermal) bitumen recovery in Alberta based on 2001 data

Data source: Alberta Environment, personal communication.

[204] Alberta Environment. 2006. *Water Conservation and Allocation Policy for Oilfield Injection*, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf and *Water Conservation and Allocation Guideline for Oilfield Injection*, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

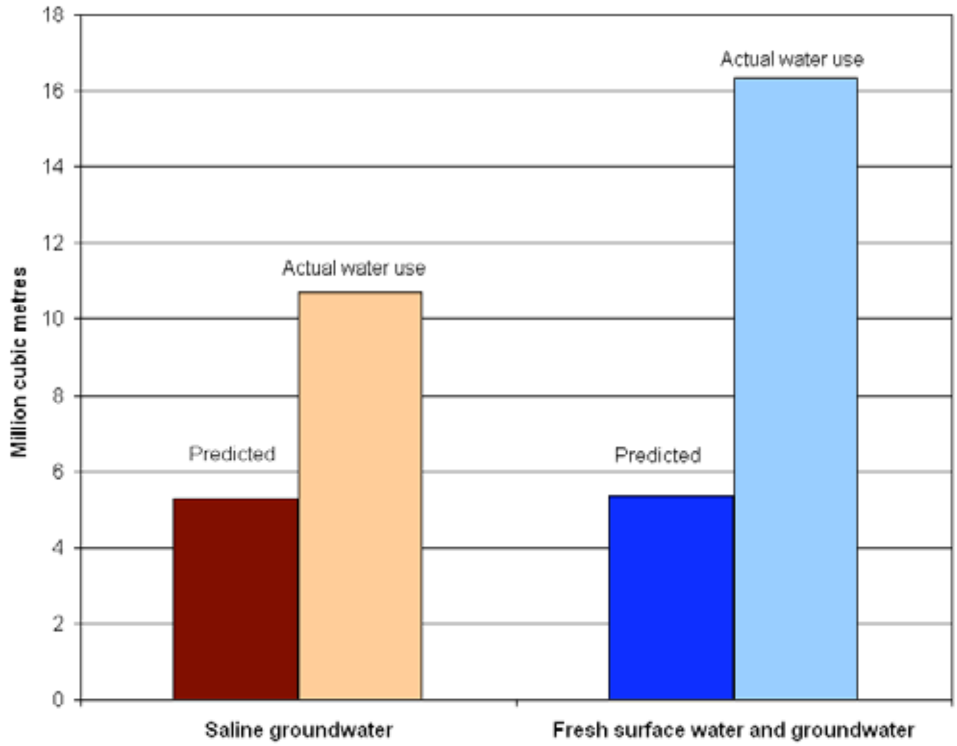

Figure 2-20 Predicted and actual use of saline and fresh water for in situ bitumen recovery in Alberta, 2004

Data source: Data used to construct Figures 2-18 and 2-19. N.B. The saline water use in 2004 includes 8.9 million m^3 used for cold enhanced recovery of bitumen. All the fresh water was for thermal enhanced recovery.

Since the EUB expects the production of bitumen by in situ methods to increase from 61.4 m^3/day in 2004 to 148 m^3/day in 2014 (an increase in production of approximately 240%),[205] unless new technologies are introduced that use less water, a significant increase in the demand for water can be expected.

Individual companies differ in the type of water that they use. The main in situ projects are listed in Table 2-5.[206] The table does not include small-scale pilot projects, except for Whitesands Insitu Ltd.'s experimental Toe-to-Heel Air Injection (THAI™) project. With the exception of the THAI process, all use considerable quantities of water to generate steam to extract the bitumen. Some CSS projects in the Cold Lake and Peace River areas use surface water, while many of the SAGD projects in the Athabasca area use fresh groundwater. At the time of writing, two SAGD projects in the Cold Lake area use or plan to use only saline groundwater, as does one SAGD project in the Athabasca area. The type of water used may also vary between different projects operated by the same company. Thus Husky Energy uses saline water for its Tucker Lake project, but is expected to use fresh water at its later Sunrise project. Imperial's Cold Lake operation normally uses surface water, but the company has a licence to withdraw groundwater

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[205] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview*. Statistical Series (ST) 2005-98, p. 2-16 and 2-17, http://www.eub.gov.ab.ca/bbs/default.htm

[206] For a full list of oil sands projects, both mining and in situ, see Todd Hirsch. 2005. *Treasure in the Sand: An Overview of Alberta's Oil Sands Resources.* Appendix A: Inventory of Existing and Planned Oil Sands Projects. Canada West Foundation, p. 16–18, http://www.cwf.ca/abcalcwf/doc.nsf/publications?ReadForm

when the surface of Cold Lake falls below a specified level. Suncor pipes recycled water from its oil sands mine plant site to its Firebag in situ project.

As many of the new projects will develop in stages, Table 2-5 shows (as far as possible) the expected demand for water over the period 2005–2025 when most stages are operational, since this is of most significance for the environment.[207] The table only includes projects that have been proposed and more projects and expansions are expected to be constructed within the next 20 years. The figures are given for average operations. Daily rates are based on annual rates, divided by 365, so do not take into consideration plant turnarounds and other factors that reduce volumes. During the start up of a project, the water demand may be considerably higher than the figures given. The table gives the water use for the oil recovery process and figures do not include water required for on-site utilities (e.g., drinking, cooking, sewage). In most cases the initial data was obtained from EIAs; this information was then sent to each company for verification or amendment. Since we attempt to provide the average information for a 20-year period, companies often needed to qualify the figures. Thus readers are asked to look at the footnotes to this table, before interpreting the data. If the projections in Table 2-5 for the period 2005–2025 prove to be correct, only two-fifths of the water will come from saline sources. Over 37% of water would be withdrawn from fresh groundwater sources and 22% from surface water.

Table 2-5 Projected annual water use and bitumen production for major in situ oil sands recovery projects in Alberta, 2005–2025

Project	Company	Project Type	Projected water use 2005–2025 m^3/year			Bitumen production	
			Surface	Fresh GW	Saline GW	m^3/day	Barrels per day
Athabasca Region							
Christina Lake[208]	EnCana	SAGD	—	500,000	2,250,000	11,200	70,000
Firebag[209]	Suncor	SAGD	2,235,100	—	—	22,260	140,000
Hangingstone	JACOS[210]	SAGD	—	286,500	—	1,750	11,000
Jackfish[211]	Devon Energy	SAGD	—	—	406,000	5,565	35,000
Joslyn Creek[212]	Deer Creek	SAGD	—	312,200	—	4,295	27,000
Long Lake[213]	Opti/Nexen	SAGD	—	1,857,100	1,204,500	11,200	70,000

[207] All the projects listed are in operation or planned and have submitted an application to Alberta Environment and the EUB, so are able to anticipate the expected water use, and so on. BlackRock's Ventures project is expected to start operations in 2007, ConocoPhillips' Surmont project in 2006, Devon Energy's Jackfish project in 2007, Husky Energy's Tucker Lake in 2006, and Opti's Long Lake project in 2007. Data source: Individual companies. Some older projects have expansions planned or underway and data for planned expansions has been included in the table, where available, even if not yet approved.

[208] Detailed design of production for 11,200 m^3/day has not begun, thus volumes are estimates based on extrapolation from current phase 1B, which produces about 3,200 m^3/d. EnCana plans to reduce the volume of fresh groundwater for the Christina Lake project, to the extent practicable, providing saline groundwater is available in the area.

[209] The Firebag project uses water recycled from another facility that was originally drawn from the Athabasca River.

[210] Japan Canada Oil Sands.

[211] The water figure includes water recovered from the McMurray formation with the bitumen.

[212] Deer Creek also has a mining operation at Joslyn Creek, but these figures are for the in situ recovery only.

MacKay River[214]	Petro-Canada	SAGD	—	1,387,000	—	11,160	70,000
Meadow Creek[215]	Petro-Canada	SAGD	—	792,780	—	12,700	80,000
Sunrise[216]	Husky Energy	SAGD	—	1,935,600	—	32,000	200,000
Surmont[217]	ConocoPhillips	SAGD	—	2,414,800	—	15,900	100,000
Whitesands[218]	Whitesands Insitu	THAI	—	21,900	—	300	1,880
Cold Lake Region							
Cold Lake[219]	Imperial Oil	CSS	3,040,000	950	1,269,000	30,000	180,000
Foster Creek[220]	EnCana	SAGD	—	1,451,000	2,960,000	At least 15,900	At least 100,000
Orion	BlackRock Ventures	SAGD	—	—	100,600	3,100	19,000
Tucker Lake[221]	Husky Energy	SAGD	—	—	1,788,500	4,770	30,000
Wolf Lake/ Primrose[222]	CNRL	CSS	—	1,537,000	3,288,000	14,000	88,200
Peace River Region							
Peace River[223]	Shell	CSS	2,076,000	—	—	1,280	8,050

Date source: Individual companies[224]

[213] Water volumes for the Long Lake project include water use for the upgrader and co-generation plant, so are not directly comparable with other figures in the table. The figures provided are for Phase I. The water requirements for Phase II are not yet available.

[214] The figures for Petro-Canada's MacKay River facility reflect both the current operation and a proposed expansion that has not yet been approved.

[215] Petro-Canada's Meadow Creek project is on hold.

[216] The water for the Sunrise project comes from the basal McMurray water sands in contact with the McMurray oil sands. Husky Energy currently plans to use water from locations on the Imperial Oil lease that would otherwise be depressurized by Imperial as part of their Kearl Mine proposal.

[217] ConocoPhillips is exploring saline sources for use in Phase 1 or future phases of the Surmont project. The current approval for Phase 1 is for 693,720 m^3/year, which may be in excess of actual requirements.

[218] Whitesands Insitu Ltd.'s THAI project is scheduled to start steaming in February 2006 and begin air injection three months later. During year one the water demand for the Whitesands Pilot Project is projected to be 82,125 m^3/d, while the operational demand is 21,900 m^3/year. Water will be required for three months to steam the formation, and bring the reservoir to combustion temperatures. During commercial production a large portion of the start-up and operational water demand will be met by using connate water that is in the ground and produced with the bitumen. See section 4.3.

[219] Imperial also has a contingency groundwater licence, but this can only be used if the company is not allowed to withdraw surface water from Cold Lake, when lake levels fall. This groundwater licence volume is not recorded in the table. Saline water is being used to prevent an increase in fresh water use during start up.

[220] EnCana has an approval to produce up to 18,025 m^3 bitumen per day at its Foster Creek operations. Future water use is projected from current operations. EnCana plans to expand within the capacity of its current fresh water licences, reducing the volume of fresh water relative to saline water as it expands its operations.

[221] The TDS in the water used by Husky Energy for this project will be approximately 20,000 mg/l.

[222] Water values are for 2005–2020, not 2005–2025, to be consistent with data CNRL supplied to Alberta Environment in 2004. The bitumen production is the volume specified in CNRL's current approval.

[223] Figures are for current operations for 2004 only. Shell is planning an expansion at Peace River, but the water requirements for that project are not yet determined. Expected average water use from 2005 to 2025 is not available until water requirements for the expansion are determined.

[224] The Pembina Institute initially obtained the information from company applications for approval to the EUB and Alberta Environment. These applications include EIAs. These large volumes are available in print form at the Alberta Environment library in Edmonton and the EUB library in Calgary. Each company was asked to verify whether the information was still current, and to update the figures as needed. More information on individual projects can be obtained by reading the EIAs.

3. Environmental impacts

3.1 Capability to evaluate impacts on water

3.1.1 Baseline information on surface water

To understand the impacts of current and future developments on the province's water resources, it is first necessary to have reliable baseline data and an appreciation of the factors that may affect that data in the future. For surface water this means having not only long-term records of river flows and an understanding of the way influences such as damming, demand and droughts impact those flows, but also understanding the potential future impact that could result from climate change. In addition to simply considering the direct impacts that water withdrawals can have on the aquatic ecosystem, it is necessary to consider and evaluate potential effects on water quality. In light of the fact that we discharge effluent into surface water bodies and rely on dilution to avoid negative water quality impacts, it is necessary to consider how changes in the flows or volumes of surface water bodies due to withdrawals may negatively impact water quality, and in turn the aquatic ecosystem and/or downstream water users.

Until recently, when Alberta Environment granted a licence for water withdrawal, they assessed whether there was sufficient water to meet demand. Since they did not have a comprehensive record of the actual volumes used for all purposes (not just for oil development), it was not possible to ascertain what the impact on the surface water (or groundwater) would be if all allocations were fully used. In northern Alberta the Athabasca River has large flows, but there are seasonal variations, with low flows during winter. Several large allocations from the river have been made while work is underway to determine the instream flow needs (IFN) of the river. Recent licences issued by Alberta Environment include explicit reference to the department's right to review and revise licences to curtail withdrawals during times of reduced flow and provide for a renewal every ten years.

Although surface water and groundwater require separate examination, it is important to remember that they are closely related.[225] Connections exist between groundwater and surface water. Depending on the situation, a river can either gain flow from groundwater or, when groundwater levels are low, provide a source for the recharge of groundwater.

3.1.2 Information on groundwater in Alberta

According to a recent report, "Knowledge and information are the backbone of any water management scenario."[226] Sound information on groundwater is essential for determining the

[225] Winter, Thomas C., Judson W. Harvey, O. Lehn Franke and William M. Alley. 1998. *Ground Water and Surface Water: A Single Resource.* U.S. Geological Survey Circular 1139, http://pubs.usgs.gov/products/books/circular.html See also William M. Alley, Thomas E. Reilly and O. Lehn Franke. 1999. *Sustainability of Ground-Water Resources.* U.S. Geological Survey Circular 1186, http://pubs.usgs.gov/products/books/circular.html

[226] Rivera, Alfonso. 2005. How well do we understand groundwater in Canada? A science case study. In Linda Nowlan. 2005. *Buried Treasure: Groundwater Permitting and Pricing in Canada,* p. 6. Report prepared for the Walter and Duncan Gordon Foundation, http://www.gordonfn.org/FW-pubs&links.cfm

water balance in each river basin. Much more information is needed about groundwater in Alberta to ensure that its management is sustainable. It is important to understand the close relationship between surface water, groundwater and aquatic ecosystems in a watershed, recognizing that subsurface flows may differ from those on the surface. We need to know the recharge rates of regional and local aquifers and the average residence time of water in an aquifer. A good overview of the main factors involved in the sustainability of regional aquifers is provided in a study compiled for the report *Buried Treasure: Groundwater Permitting and Pricing in Canada.*[227] Sound knowledge of both regional and local aquifers is required to ensure that groundwater resources are not depleted.

In the 1970s the Alberta Geological Survey (AGS) and Alberta Research Council created maps that showed hydrogeological information from which it was possible to derive groundwater flow directions. The maps showed estimates of the yield but did not cover the entire province. Even where maps exist, they may be based on inadequate information, for water levels are interpolated between a limited number of wells and the reliability of the maps depends on the density of the well network.

It is important to understand which areas are recharging groundwater, and any impacts in the recharge areas that may alter the rates of recharge experienced in the past. In some northern areas of the province there are deep buried glacial valleys that provide a valuable groundwater resource (e.g., buried Beverly Valley and buried Helena Valley[228]), but research is still in progress to understand how rapidly these channels are being recharged (see section 3.3.3.2, below).

Changes in groundwater can be studied only through a wide network of monitoring wells and analysis of the data it supplies. This will indicate the impact that demand and drought has had on groundwater in the past and how changes in river flows and wetland areas may affect the fresh water aquifers in the future. However, it may not be easy to accurately determine the long-term yield of an aquifer, especially as this can be impacted by climate change and withdrawals in the recharge area of an aquifer.

Alberta Environment monitors approximately 170 wells in its groundwater observation well network (GOWN),[229] and there are further wells in the provincial ambient groundwater quality system, but there are many gaps and deficiencies in the system. According to a recent consultants' report, "in the past, due to budgetary constraints, [Alberta Environment] has had to curtail its groundwater monitoring activities."[230] Although some monitoring wells were installed in the late 1970s in the Athabasca oil sands area, some were improperly constructed and some have been dry since installation. The report indicates, "Groundwater monitoring coverage

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[227] Rivera, Alfonso. 2005. How well do we understand groundwater in Canada? A science case study. In Linda Nowlan. 2005. *Buried Treasure: Groundwater Permitting and Pricing in Canada,* p. 6. Report prepared for the Walter and Duncan Gordon Foundation, http://www.gordonfn.org/FW-pubs&links.cfm

[228] For an example of a buried channel, see Hydrogeological Consultants Ltd. 2002. *Regional Groundwater Assessment for the M.D. of Bonnyville.* Conducted for the Prairie Farm Rehabilitation Administration, p. 13, Figure 9 "Cross Section E-E'" showing the buried Beverly and Helena valleys, and p. 7, Figure 6 "Generalized Cross-Section (for terminology only)", http://www.10704.com/pdf/rgwa/bonnyville.pdf

[229] Alberta Environment's Groundwater Observation Well Network, http://www3.gov.ab.ca/env/water/gwsw/quantity/waterdata/gwdatafront.asp In 2005 the number of wells was approximately 172. Alberta Environment, personal communication, September 2005. The main network is supplemented with manual measurements taken several times a year from about 200 project wells, while approximately 100 additional shallow stainless steel wells are monitored for groundwater quality every few years. Alberta Environment, personal communication, September 2005.

[230] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 36. Prepared for Alberta Environment.

improves starting from the eastern part of the North Saskatchewan River and Beaver River Watershed towards the South."[231] But there are also gaps elsewhere. Referring to a map within the report, the consultants state, "Lack of monitoring wells in Northern Alberta, as well as in the major regional units/aquifers like the Paskapoo Formation, Horseshoe Canyon Formation, Belly River Formation, Bearpaw Formation, Oldman Formation and Milk River Formation, is clearly evident."[232] Some of these formations are predominantly in southern Alberta, where conventional oil recovery uses water.

The Prairie Farm Rehabilitation Association (PRFA) has worked with many Alberta municipalities to provide an initial evaluation of the groundwater resource.[233] Their reports describe the hydrogeology and location of water wells within a municipality, and provide information on the apparent yield and chemical quality of the water for different aquifers, but do not provide information on the sustainability of aquifers.[234] Also, since these reports use the Alberta Environment database as a primary source of information, they suffer from the same limitations as that database.

It is essential to improve knowledge of Alberta's groundwater to ensure the resource is not over-allocated. Although it is a renewable resource, if demand exceeds the rate of recharge, aquifers become depleted to such an extent that they no long provide a viable source of water. Excessive withdrawals may also have other consequences. For example, according to a recent report, "In some instances, lowering of the groundwater surface may trigger aeration of a portion of previously saturated aquifer. Aeration or cyclic aeration may lead to unfavourable hydrochemical changes (e.g., dissolution of metals). Under this scenario, water may require expensive treatment prior to distribution for domestic use, and long-term availability may also be reduced."[235]

Having identified short-comings in the government's baseline data, we will now examine the impacts the development of oil has on water resources. While some of these impacts are already known, there are also gaps in knowledge about the potential future impacts of activities that may affect aquifers.

3.2 Impacts of oil sands mining

3.2.1 Water withdrawals from the Athabasca River

Water use has been identified as one of the top four key challenges for mining operations.[236] Mining operations require more fresh water per cubic metre of oil than other forms of oil extraction; water is removed from the Athabasca River basin and tied up for an indefinite period

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[231] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 34. Prepared for Alberta Environment.

[232] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 34. Prepared for Alberta Environment.

[233] These reports were written by Hydrogeological Consultants Ltd., and are available on their website at http://www.hcl.ca/reports.asp The reports tried to link the information on licensed water wells with wells listed in the Alberta Environment groundwater database, but this was not always possible.

[234] See section 3.3.2.1 below, which refers to the PRFA report for the M.D. of Bonnyville.

[235] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report,* p. 48. Prepared for Alberta Environment. The over-exploitation referred to in the citation is different from the natural annual cycle in an unconfined aquifer.

[236] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap : Unlocking the Potential. Final Report,* Figure 3.3, p. 21, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf.

of time.[237] The Athabasca River is subject to variable seasonal flows (Figure 3-1), with the lowest flow periods occurring between November and March.[238] In addition, Athabasca River flows are highly variable from year to year and could be affected by climate change. A statistical analysis of the Athabasca River flows from 1958 to 2002 demonstrated a statistically significant (at the 5% level of significance) decrease in recorded flows.[239]

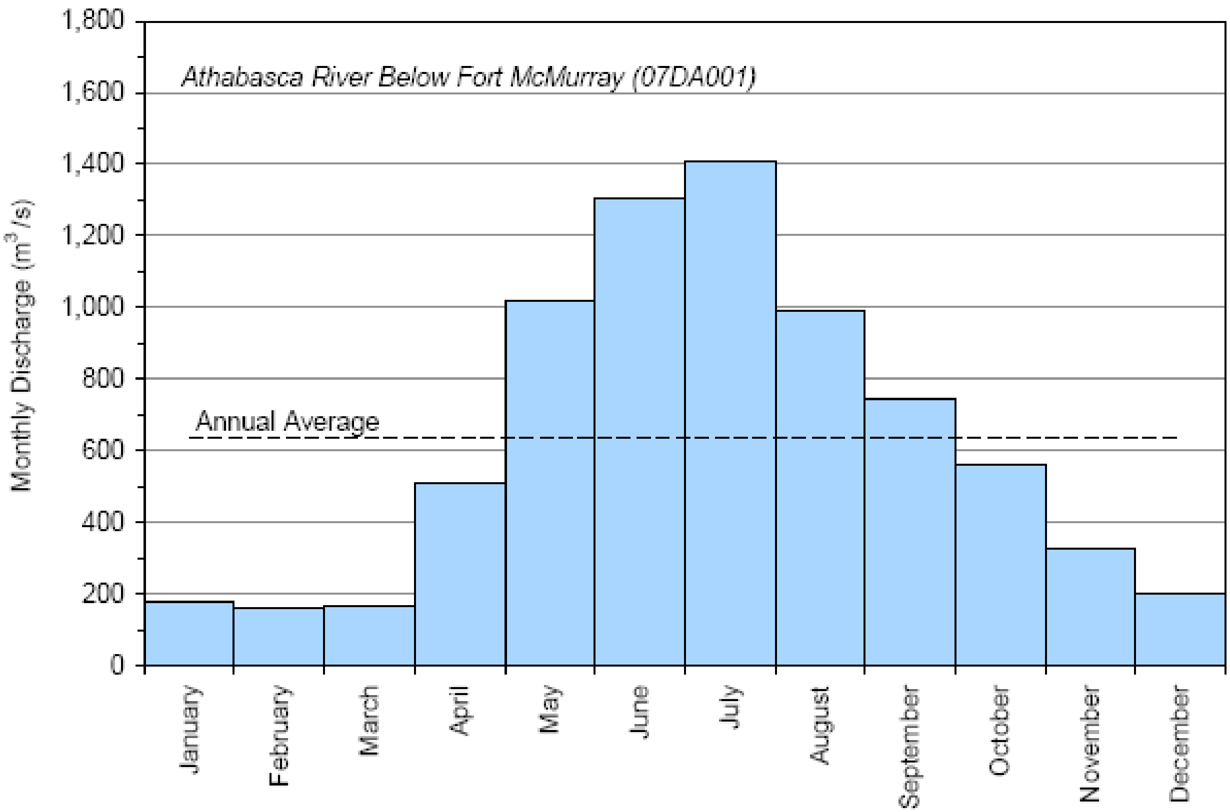

Figure 3-1 Mean monthly flows recorded at the Athabasca River below Fort McMurray Station (Period of record: 1958–2002)

Source: Figure taken from Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group. Figure 6.

The ecological integrity of Alberta's aquatic ecosystems requires that adequate flows and seasonal variations in flow be maintained. As has been evidenced by the impact of the Bennett Dam on the Peace/Athabasca Delta—a drastic decline in spring floods that has resulted in the drying of the Delta area—reductions in even the seasonal flow of rivers can have serious impacts. These relationships demonstrate that, to effectively protect the aquatic environment, the natural flow regime, seasonally and from year to year, is required. Scientifically, this relationship

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[237] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet*, p. 34; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[238] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group, p. 17.

[239] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group, p. 19.

is referred to as the river's IFN and represents the amount of water, flow rate or water level that is required in a river to sustain a healthy aquatic environment or to meet human needs such as recreation, navigation, waste assimilation or aesthetics. It is unlikely that the planned water withdrawals by oil sands mining operations will affect recreation, navigation, waste assimilation or aesthetics of the Athabasca River, so understanding the needs of the aquatic ecosystem are the priority. Fish populations are considered to be the most vulnerable component of the aquatic ecosystem, particularly during the winter low flows when water withdrawals could significantly reduce the availability of habitat for those species that overwinter in the Athabasca River. Field studies and the knowledge of regional First Nations and Métis groups have demonstrated that multiple fish species (including long nose sucker, burbot, walleye, and goldeye) use the Athabasca River during the winter period, and therefore may be vulnerable to the cumulative effect of water withdrawals for oil sands mining operations.

The Surface Water Working Group (SWWG) of the Cumulative Environmental Management Association (CEMA)[240] has been working since 2000 to develop a defensible, science-based IFN recommendation that provides full, long-term protection to the aquatic ecosystem of the lower Athabasca River. It should be noted that determining the IFN for a river during a period of ice cover is a complex task due to the logistical constraints of assessing fish habitat use and movements under ice; to date, the efforts of CEMA represent the first detailed winter ice-cover IFN study and recommendation in North America. These scientific hurdles, coupled with the challenges of obtaining adequate funding and relative prioritization within CEMA's scope of work, and identifying and obtaining scientific expertise, resulted in the IFN determination taking significantly longer than was originally contemplated.[241]

The lack of understanding of the IFN of the Athabasca River resulted in considerable concern amongst regional stakeholders that Alberta Environment continued to grant licences for water withdrawals from the Athabasca River.[242] To address this concern Alberta Environment included specific conditions within recent water licences that explicitly reserve the right to establish an IFN and to amend licences to reduce the quantity or rate of water diverted from the Athabasca River.[243] In addition, Alberta Environment noted on several occasions that all *Water Act* licences for oil sands projects include provisions for amendment of the licence conditions to reflect the implementation of an IFN management system.[244]

Because of the magnitude of currently licensed withdrawals from the Athabasca River and because the IFN for the Athabasca River was unknown, it has become one of the most significant environmental issues facing the oil sands mining industry and has figured prominently in recent

[240] CEMA was established in 1999 to serve as a consensus-based, multistakeholder forum for supporting the Government of Alberta's RSDS for the Athabasca Oil Sands Region. CEMA was tasked with collecting information on the environmental thresholds of the Athabasca Oil Sands Region and recommending management systems to address cumulative environmental effects to the Government of Alberta.

[241] In 2002, the SWWG's workplan anticipated completion of the scientific IFN recommendation in the 3rd quarter of 2003, management objectives in the 1st quarter of 2004, and a management system design by the 2nd quarter of 2004. The 2003 workplan presented the goals of completing the scientific IFN recommendation in 2004, and the IFN management system in 2005.

[242] For example, see Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* section 13, p. 34-43.

[243] For example, see CNRL's Licence No. 00186921-00-00 or Shell's Licence No. 001861757-00-00 at http://www3.gov.ab.ca/env/water/approvalviewer.html

[244] Marriott, Patrick. 2004. *Water in the Oil Sands Industry*. Alberta Environment. CONRAD Water Use Workshop. February 24–25, 2004.

regulatory hearings for proposed oil sands mines.[245] Within the presentations and cross-examinations of Alberta Environment, Alberta Sustainable Resource Development and the federal Department of Fisheries and Oceans (DFO), these government agencies committed to cooperatively develop and implement an IFN management system for the lower Athabasca River by December 31, 2005, in the event that CEMA failed to deliver an IFN recommendation by this date.[246]

Since CEMA failed to meet this deadline, the Alberta government took over the task of determining the Athabasca River's IFN and developed the IFN interim framework to fulfill its commitment.[247] On January 25, 2006 the *Interim Framework: Instream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River* was introduced, "to protect the aquatic ecosystem of the lower Athabasca River and to ensure development can occur without threatening long-term ecosystem sustainability."[248] The interim framework provides a series of flow-rate thresholds, which identify different potential environmental impacts and the required management action. However, the Pembina Institute contends that the interim framework is not adequately precautionary and protective, and relies too much on voluntary actions by companies to protect the river.[249] Economic alternatives to withdrawing water at low flows on the river are available, such as building off-river water storage and improving water conservation. These alternatives will only be developed if the government implements rules based on the precautionary application of science and clearly defines mandatory management actions.

The announcement of the draft Mineable Oil Sands Strategy (MOSS) in October 2005 indicates that oil sands mine operators should coordinate development projects so that "water is managed throughout the zone to optimize resource recovery, water use and to maintain the Athabasca River,"[250] but does not provide details on how this will be accomplished or the parameters that will define the maintenance of the Athabasca River.

3.2.2 Groundwater drawdown

In some parts of the surface mineable oil sands area, it is necessary to depressurize the basal aquifer to prevent flooding of the mine pits. As noted earlier, in most cases this water is retained

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[245] For example, water withdrawals and the IFN of the Athabasca River figured prominently in the Joint Review Panels held in 2003 for both the Canadian Natural Resources' Horizon project, and Phase 1 of Shell's Jackpine Mine project. For a summary of the issues discussed, see the Joint Panel Decision reports at http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-005.pdf and http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-009.pdf, respectively.

[246] These commitments were reflected in the Joint Panel's recommendations included in the decision reports on hearings. For example, Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 41.

[247] At Joint Panel regulatory hearings in 2003 for proposed oil sands mines, Alberta Environment, Alberta Sustainable Resource Development and the federal DFO committed to cooperatively develop and implement an IFN management system for the lower Athabasca River by December 31, 2005, in the event that CEMA failed to deliver an IFN recommendation by this date. These commitments were reflected in the Joint Panel's recommendations included in the decision reports for both of these projects. For example, see Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 41.

[248] Alberta Environment. 2006. *Interim Framework: Instream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River,* p. 18. The Government of Alberta asked for public comments on the interim plan by March 20, 2006. Letter from Ernie Hui, Alberta Environment, Northern Region, Regional Director, to the Cumulative Environmental Management Association. January 26, 2006.

[249] Woynillowicz, Dan and Chris Severson-Baker. 2006. *Down to the Last Drop: The Athabasca River and Oil Sands,* www.oilsandswatch.org

[250] Government of Alberta. 2005. *Mineable Oil Sands Strategy,* p. 4, http://www.energy.gov.ab.ca/docs/oilsands/pdfs/MOSS_Policy2005.pdf

by operators and used within the extraction process. The removal of water from nearby aquifers can lower the overall water level in an area and can result in changes in the water levels of other aquifers and surface water bodies, including wetlands that are dependent on groundwater recharge.

While the effects of basal depressurization on Athabasca River flows are considered very small compared to the water withdrawals of mine operators,[251] this activity does influence the interaction (both direction and scale) between groundwater and the Athabasca River. For example, at various stages of the Canadian Natural Resource's Horizon mine project regional groundwater will cease to discharge to the Athabasca River as normally occurs, and the flow will reverse with the basal water sands recharging from the Athabasca River. During these periods the maximum net reduction in discharge from the basal water sands has been predicted to reach a worst-case maximum of almost 30,000 m^3 per day.

In addition, the dewatering of aquifers may have the potential to cause a decrease in water levels in surrounding wetland areas. For example, in its EIA, CNRL noted that, based on a 500-metre buffer surrounding its Horizon mine, basal aquifer depressurization will have a potential drawdown zone of 9,820 ha, including 373 ha of wetlands.[252]

While there is a good understanding of the impacts on aquifers close to mining operations, impacts over a wider region are not well understood.[253] It appears that oil sands mining projects are proceeding in the absence of a complete assessment of their potential environmental impacts or the adequacy of their mitigation plans. Currently, little contingency planning is undertaken to address drawdown impacts on adjacent wetlands.[254] While operators conduct comprehensive wetlands monitoring programs to identify surficial and basal aquifer drawdown effects, should these programs detect effects it will be difficult to stop the dewatering process once it has begun without risk of mine pit flooding.

3.2.3 Tailings ponds and long-term management

There are environmental risks and impacts associated with both the storage of tailings in tailings ponds, and the long-term management of tailings in a reclaimed landscape. In light of these impacts, the Alberta Chamber of Resources has noted, "Current practices for long-term storage of "fluid" fine tailings pose a risk to the oil sands industry" and suggested that the industry "is likely to come under increasing scrutiny from all stakeholders including regulators, operators, owners, local groups, and the regional municipality of Wood Buffalo."[255]

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[251] Golder Associates Ltd. 2005. *A Compilation of Information and Data on Water Supply and Demand in the Lower Athabasca River Reach.* Prepared for the CEMA Surface Water Working Group, p. 23.

[252] Canadian Natural Resources Ltd. 2002. *Horizon Oil Sands Project. Application for Approval,* Vol. 6, Section 4, p. 4–37.

[253] Edo Nyland, Professor Emeritus, Physics, University of Alberta, personal communication, February 2006.

[254] Shell Canada. 2002. *Responses to OSEC Interim Review Report—Jackpine Mine Phase 1.* Response 145. The Basal Aquifer depressurization is necessary to prevent water seepage into the mine, and ensure integrity of the mine walls and safety during operations. The surficial aquifer dewatering is necessary to access the bitumen resource. Monitoring will be used to verify whether the results of the groundwater and hydrology models on the effects on wetlands are correct. The assessment of the impact on the lowering of groundwater levels and changes in hydrology on wetlands is classified as low environmental consequence within the RSA and low within the LSA. Shell has no contingency plans should wetlands in the vicinity of the development be affected by Basal Aquifer drawdown.

[255] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap : Unlocking the Potential. Final Report,* p. 36, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

Tailings ponds already cover an area of over 50 kilometres^2 and are some of the largest humanmade structures on the planet.[256] The National Energy Board has characterized the problem of fine tailings management as "daunting," given that the volume of fine tailings ponds produced by Suncor and Syncrude alone will exceed one billion cubic metres by the year 2020.[257] The principal environmental threats from tailings ponds are the migration of pollutants through the groundwater system and the risk of leaks to the surrounding soil and surface water.[258] In other jurisdictions tailings ponds have been associated with significant incidents of containment losses, causing major ecological disasters and resulting in significant financial losses for companies.[259] Tailings ponds may require long-term management and threaten to become major public liabilities in the event that a company cannot cover the clean-up itself.[260] While the oil sands tailings ponds are actively monitored and maintained, and the potential for a catastrophic failure of a tailings dyke is considered low, the long-term viability of these dykes will remain an on-going concern long after operations cease, as any future failure of containment dykes could allow a release of unstable materials into the Athabasca River that would be extremely difficult to recover or mitigate.[261]

While some improvements have been made in tailings technology, namely the development of CT and thickened tailings, there remains no demonstrated means to reclaim fluid fine tailings (also referred to as mature fine tailings, or MFT). In considering Shell's Jackpine Mine–Phase 1 project, the Joint Review Panel concluded that "tailings management is one of the main challenges for the oil sands mining industry," [262] and directed the EUB to "work with the mineable oil sands industry, Alberta Environment, and Alberta Sustainable Resource Development to develop performance criteria for tailings management"[263] by June 30, 2005. In April 2005 the EUB acknowledged that the recommendations would not be complete by June 30, 2005.[264] Work within the EUB is ongoing but no firm date for its completion can be given at this time.[265] Implications arising from the uncertainty associated with reclamation using MFT is further discussed in Section 3.2.5.

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[256] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 34, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[257] National Energy Board. 2004. *Canada's Oil Sands: Opportunities and Challenges to 2015. An Energy Market Assessment,* p. 68, http://www.neb-one.gc.ca/energy/EnergyReports/EMAOil sandsOpportunitiesChallenges2015/EMAOil sandsOpportunities2015QA_e.htm

[258] National Energy Board. 2004. *Canada's Oil Sands: Opportunities and Challenges to 2015. An Energy Market Assessment,* p. 68, http://www.neb-one.gc.ca/energy/EnergyReports/EMAOil sandsOpportunitiesChallenges2015/EMAOil sandsOpportunities2015QA_e.htm

[259] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 35, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[260] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 35; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[261] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 34; http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[262]Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 25, http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-009.pdf

[263] Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 26, http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-009.pdf

[264] Alberta Energy Utilities Board, personal communication, February 8, 2006.

[265] Alberta Energy Utilities Board, personal communication, February 8, 2006.

In addition, it has been found that tailings ponds are a source of methane emissions, a potent greenhouse gas. The methane is produced by methanogenic bacteria, which are very active in tailings ponds.[266] In addition to the climate implications of the methane emissions, methane may be detrimental to the reclamation of tailings for a number of reasons:[267]

- Bubbles of methane arising from the MFT may influence the densification of fine tailings;
- Gas released from the MFT layer in water-capped fine tailings lakes results in the re-suspension of fines and leads to a destabilization of the fine tailings interface;
- Bubbles rising through the MFT and water column may strip dissolved organic compounds and lead to fugitive emissions of low molecular weight hydrocarbons and organosulfur compounds; and
- Methane released to overlying waters could increase demand on dissolved oxygen levels and lead to anoxic conditions as the methane is used by methanotrophic bacteria.

It has been found that methanogenic bacteria are out-competed by sulfate-reducing bacteria in tailings ponds, and methanogenesis only begins once sulfate is depleted.[268] Given that discovery of this phenomenon is quite recent, research is ongoing to understand the extent to which methane production occurs, the conditions under which it occurs, and what mitigation techniques might prove successful.

3.2.4 Water quality

3.2.4.1 Process affected waters

There are numerous water quality issues associated with oil sands mining operations. Most significant is the rapidly growing volume of process-affected water that cannot be discharged back to the environment due to its poor quality. Wastewaters from these operations, most of which are treated, include sewage, refinery effluent/cooling water/dyke seepage, site drainage (muskeg, overburden, mine run-off), mine depressurization water, and tailings release water (CT via EPLs).[269] In addition, water that comes into contact with coke, asphaltenes, sulphur, heavy metals and other streams rejected from upgrading processes must be stored and managed (treated or disposed of) properly to prevent contamination of watersheds.[270]

While existing industrial effluent limits and "Protection of Aquatic Life" water quality guidelines provide a measure of protection, they do not encompass[271]

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[266] Fedorak, P. M., D.L. Coy, M.J. Salloum, and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology*, Vol. 48, p. 22. http://cjm.nrc.ca

[267] Fedorak, P. M., D.L. Coy, M.J. Salloum, and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology*, Vol. 48, p. 22. http://cjm.nrc.ca

[268] Fedorak, P. M., D.L. Coy, M.J. Salloum, and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology*, Vol. 48, p. 22.

[269] McEachern, Preston. 2004. *Water Quality Issues for the Oil Sands and Current Management Status*. Alberta Environment. CONRAD Water Use Workshop. February 24–25, 2004.

[270] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet*, p. 45, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[271] McEachern, Preston. 2004. *Water Quality Issues for the Oil Sands and Current Management Status*. Alberta Environment. CONRAD Water Use Workshop. February 24–25, 2004.

- downstream obligations, such as Wood Buffalo National Park, through which the Athabasca River passes north of the surface mineable region;
- site-specific water quality, such as high total suspended solids (TSS) and metals; and
- important substances, such as naphthenic acids.

Tailings materials have been found to contain residual bitumen and diluent (e.g., naphtha, where used). For example, in one study it was found that MFT from Suncor's tailings pond contained 9% residual bitumen.[272] Recognizing that tailings materials will be integrated into the reclaimed landscape (in the case of CT) or disposed of in EPLs (in the case of MFT), both surface water and groundwater will pass over and through these materials, resulting in potential water quality impacts.

Naphthenic Acids — Of growing concern is the presence of naphthenic acids in tailings ponds and local water bodies, and their potential impacts on water quality and fish tainting. Significant attention has been drawn to naphthenic acids as a result of their persistence in the environment and their aquatic toxicity at the levels found in tailings ponds.[273] Naphthenic acids are a naturally occurring constituent of bitumen that are soluble and become concentrated in tailings as a result of the bitumen extraction process. Concentrations of naphthenic acids in rivers within the Athabasca oil sands region are generally below 1 mg/l, but may be as high as 110 mg/l in tailings waters.[274] The most significant environmental contaminants and toxic components in oil sands deposits and tailings pond water are naphthenic acids of low molecular weight. However because hundreds of these compounds are found in oil sands materials, it is not currently known which specific naphthenic acids are the most toxic. The water in tailings ponds is acutely toxic to aquatic organisms[275] and mammals.[276] While recent mammalian toxicological results indicate that acute toxicity in wild mammals is unlikely under worst-case exposure conditions, repeated exposure may have adverse health effects.[277] As a result, a recent study concluded that reclamation of tailings into terrestrial and aquatic landscapes at the end of an oil sands mining operation must "address residual levels of naphthenic acids and their rate, fate, and transport in the environment."[278]

Given the above, and the regional First Nations' and Métis' ongoing consumption of fish and game, significant concern about naphthenic acids was raised at the Joint Panel Review of Canadian Natural Resource's Horizon project. For example, Environment Canada noted that it

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[272] Fedorak, P. M., D.L. Coy, M.J. Salloum, and M.J. Dudas. 2002. Methanogenic potential of tailings samples from oil sands extraction plants. *Canadian Journal of Microbiology,* Vol. 48, p. 24.

[273] Headley, John V. and Dena W. McMartin. 2004. A review of the occurrence and fate of naphthenic acids in aquatic environments. *Journal of Environmental Science and Health, Part A: Toxic/Hazardous Substances & Environmental Engineering,* Vol. 39, No. 8, p. 1989–2010.

[274] Conrad Environmental Aquatics Technical Advisory Group (CEATAG). 1998. *Naphthenic Acids Background Information Discussion Report*. Edmonton, AB: Alberta Department of Energy.

[275] MacKinnon, M.D. and H. Boerger, H. 1986. Description of two treatment methods for detoxifying oil sands tailings pond water. *Water Pollution Research Journal of Canada,* Volume 21, p. 496–512.

[276] United States Environmental Protection Agency (USEPA) Office of Toxic Substances. 1984. *Fate and Effects of Sediment-bound Chemicals in Aquatic Systems.* Proceedings of the Sixth Pellston Workshop. Florissant, CO, August 12–17, 1984.

[277] Rogers, V.V., M. Wickstrom, K. Liber, and M.D. MacKinnon. 2002. Acute and subchronic mammalian toxicity of naphthenic acids from oil sands tailings. *Toxicological Sciences,* Volume 66, p. 347–355.

[278] Headley, John V. and Dena W. McMartin. 2004. A review of the occurrence and fate of naphthenic acids in aquatic environments. *Journal of Environmental Science and Health, Part A: Toxic/Hazardous Substances & Environmental Engineering,* Vol. 39, No. 8, p. 1989–2010.

did not believe that there was enough information on naphthenic acids to accurately assess their effects on fish and suggested that considerably more could be done to understand the issue of fish tainting.[279]

Recent research on the fate of naphthenic acids in oil sands tailings has concluded that, "Innovative research related to the exploitation of natural systems for the removal of naphthenic acids in tailings waters is still required."[280] Similarly, in its Decision Report, the Joint Panel concluded, "a higher priority should be placed on understanding naphthenic acids and their impacts on fish tainting,"[281] but stopped short of recommending that either CNRL or a government agency undertake this research. However, research is being undertaken by companies to understand the fate of naphthenic acids under the Canadian Oil Sands Network for Research and Development (CONRAD).

Mercury — The release of mercury into surface water bodies has also been raised as a concern. In its submission to the Joint Review Panel for the CNRL's Horizon project, the Mikisew Cree First Nation (MCFN) presented an analysis that predicted mercury levels in Calumet Lake and the proposed compensation lake would become elevated as a result of flooding the vegetation, not unlike the effects observed when reservoirs are created. [282] In addition, the MCFN noted that the stripping of wetlands containing naturally high levels of mercury might result in higher mercury concentrations in receiving waters.[283] This information was based on predictions and not site-specific information. Mercury release occurs naturally throughout the region and is know to occur in created lakes.

Need for research — The most recent regulatory hearings for oil sands mining projects have clearly demonstrated a need for further research into the extent of likely water quality impacts arising from these operations. For example, at the Joint Panel Review of CNRL's Horizon project, Environment Canada noted the following:[284]

- The EIA predicted some exceedances of the water quality guidelines and the chronic effects levels for aquatic biota. However, it was unable to assess the accuracy of those predictions because of the uncertainty inherent in the predictions themselves;
- It could not agree or disagree with CNRL's conclusion that the project would have a negligible effect on water quality due to the low number of baseline measurements and the subsequent uncertainty in predictions; and

[279] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 52.

[280] Headley, John V. and Dena W. McMartin. 2004. A review of the occurrence and fate of naphthenic acids in aquatic environments. *Journal of Environmental Science and Health, Part A: Toxic/Hazardous Substances & Environmental Engineering,* Vol. 39, No. 8, p. 1989–2010.

[281] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 53.

[282] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 44.

[283] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 44.

[284] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 45.

- It could not be absolutely certain that the potential impacts on water quality could be mitigated.

Similarly, the Department of Fisheries and Oceans (DFO) made the following statement:[285]

- There was little information on the additive or multiplicative impacts of water quality parameter interactions; and
- The effects of widespread regional oil sands development on fish tainting and fish health continued to be poorly understood.

Conversely, Alberta Environment believed that CNRL's water quality predictions were very conservative, and suggested that the EIA had identified more water quality variables as exceeding guidelines or as being of possible concern than would actually be expected to occur.[286] Noting this conservatism in the EIA, and in the face of the uncertainties identified by Environment Canada and the DFO, the Joint Panel determined that, despite the predicted exceedences of water quality guidelines, the implementation of a comprehensive monitoring plan and adaptive management strategies to ensure adherence to the water quality guidelines would mean that the Horizon project was unlikely to have significant adverse environmental effects on water quality.[287]

While there are obviously a number of increasingly significant water quality issues, little is currently being done to proactively address them in advance of a number of proposed oil sands mines seeking regulatory approval (e.g., Suncor North Steepbank Mine Extension, Shell Muskeg River Mine Expansion, Imperial Kearl, Deer Creek Joslyn Mine). While the SWWG of CEMA had initiated a working group to address many of the water quality issues described above, the group was not allocated any financial resources for 2005; hence, no work was undertaken to better understand water quality impacts and develop recommendations for a comprehensive water quality management system. However, CEMA's 2006 budget has allocated funds to advance work on the establishment of water quality objectives and a management system.[288]

3.2.4.2 Water quality effects of acidifying emissions

With the growth in oil sands development in northeastern Alberta, regional emissions of nitrogen oxides (NOx) and sulphur dioxide (SO_2) have been growing steadily, and are predicted to continue to increase. Both NOx and SO_2 are acidifying emissions that contribute to acid rain. Chemical changes caused by levels of acid deposition that exceed the buffering capacity of receiving ecosystems could modify chemical and nutrient cycling and affect biota and ecosystem functioning. In a report on acid deposition sensitivity in the Athabasca Oil Sands region conducted for CEMA, it was found that, of the 449 water bodies evaluated, exceedences of critical loads for ranged from a low of 17 water bodies (3.8% of the total) under the background

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[285] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 46.

[286] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 46.

[287] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 47.

[288] The Water Quality Task Group of CEMA has received a budget allotment of $85,000 in 2006 to work on water quality issues raised in the 1999 RSDS for the Athabasca Oil Sands Area (more specifically, RSDS issues 40a, 40b, 40c and 40d). Pat Marriott, Alberta Environment, personal communication, February 17, 2006.

(i.e., pre-development) potential acid input (PAI) deposition scenario to a high of 27 water bodies (6.0% of the total) under a worst-case scenario.[289] As suggested in previous studies, where lake sensitivity was based on alkalinity, most of the exceedences occurred in the upland regions including the Caribou Mountains, Birch Mountains, Muskeg River Uplands and Stony Mountain. However, as emissions of NOx and SO_2 rise, the regional extent of their impact is growing, resulting in increasing threats to the highly sensitive soils and lakes of northwest Saskatchewan.[290]

3.2.5 Reclaimed landscapes and end pit lakes

3.2.5.1 Tailings reclamation uncertainty

At the end of 1993 the tailings ponds of both Syncrude and Suncor collectively contained a total of about 300 million m^3 of MFT.[291] It is estimated that, if these operations continue at the current rate, over 1 billion m^3 of tailings pond water will require reclamation by 2025.[292] Currently, no single reclamation option has been developed that is capable of handling the projected volumes of fine tails in a manner that is technically, environmentally, and economically viable.

3.2.5.2 Watershed integrity

Based on existing and proposed oil sands activities, the vast majority of which are oil sands mines, it is clear that a large portion of the Muskeg River Basin will be disturbed (Figure 3-3). Syncrude's Aurora (North and South) mine, Albian Sands' Muskeg River mine and Shell's Jackpine Mine – Phase 1 are already approved and/or operating in the watershed; Imperial's Kearl Mine, Albian's Muskeg River Mine expansion, and Husky Energy's Sunrise SAGD project are currently undergoing regulatory review. It is increasingly uncertain whether this river basin can sustain this degree of industrial development and still retain any significant degree of ecological integrity.

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[289] Golder Associates Ltd. 2004. *Acid Deposition Sensitivity Mapping and Critical Load Exceedences in the Athabasca Oil Sands Region.* Prepared for the NOx/SO_2 Management Working Group of CEMA, p. ii.

[290] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 61, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[291] Fine Tailings Fundamentals Consortium (FTFC), Volume 2. Fine tailings and process water reclamation. In Alberta Department of Energy. 1995. *Advances in Oil Sands Tailings Research.* Edmonton, AB: Oil Sands and Research Division, p. 1–52.

[292] Herman, D.C., P.M. Fedorak, M.D. Mackinnon and J.W. Costerton. 1994. Biodegradation of naphthenic acids by microbial populations indigenous to oil sands tailings. *Canadian Journal of Microbiology,* Vol. 40, p. 467–477.

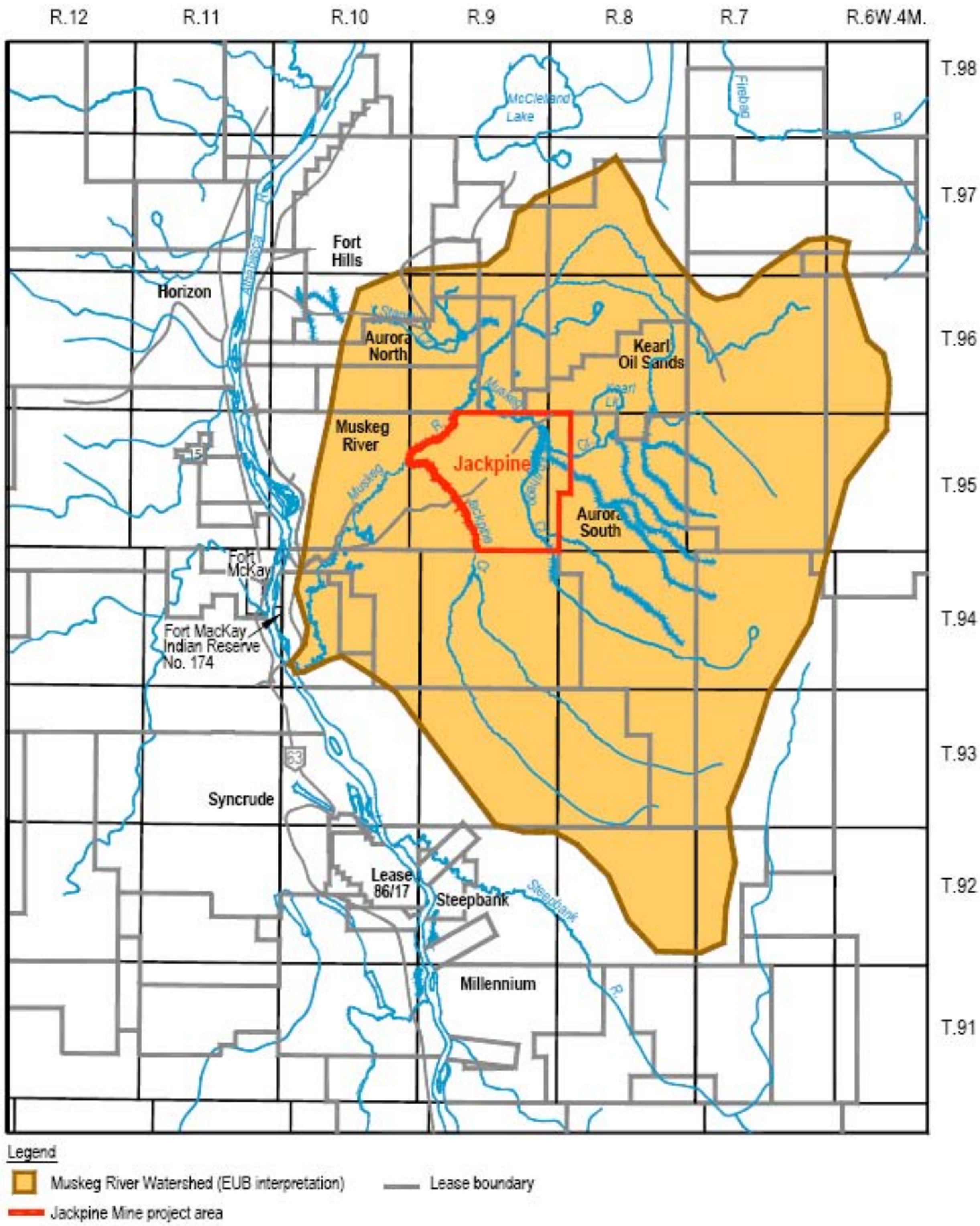

Figure 3-2 Muskeg River watershed

Data source: Alberta Energy and Utilities Board, with permission.

At the Joint Panel Review for Shell's Jackpine Mine – Phase 1 project, the long-term environmental effects of extensive oil sands development in the Muskeg River watershed were discussed. While Shell concluded that there were no unacceptable long-term environmental effects of the project,[293] Environment Canada stated that there were potential risks of irreversible effects on the Muskeg River watershed as a result of the operation and reclamation of multiple oil sands projects in that watershed.[294]

In 2002, CEMA's Muskeg River Watershed Integrity (MRWI) Workshop raised more questions than it answered. It was readily apparent that significant work was required to better understand the watershed and to develop a management system that would preserve its integrity. As a result, CEMA is undertaking work through the MRWI subgroup to develop management objectives and guidelines for the sustainability of the Muskeg River drainage basin that will contribute to a framework for cumulative environmental effects management within the basin. The Joint Panel stated that, for an area of intensive oil sands development such as the Muskeg River drainage basin, high priority should be given to developing a management system that would enable future development to proceed in an appropriate way.[295] In addition, the Joint Panel acknowledged Alberta Environment's commitment to take necessary action should the MRWI subgroup fail to meet its 2005 deadline for the delivery of recommendations; it suggested that Alberta Environment develop management plans and objectives for the basin if MRWI subgroup timelines were not met.[296] As of April 2006, the MRWI has not provided Alberta Environment with any recommendations and it is unclear how Alberta Environment intends to proceed. The Government of Alberta's draft Mineable Oil Sands Strategy (MOSS) places the highest priority on recovering mineable oil sands and focuses on reclamation efforts rather than maintaining ecological integrity throughout the development period.[297] At the time of writing this policy is under review but, if adopted, will significantly influence the work of the MRWI subgroup and its objectives.

3.2.5.3 Loss of wetlands and peatlands

Wetlands occur throughout the oil sands surface mineable area, with bog and fen peatlands representing the characteristic wetland type in the region. Wetlands play an important ecological service in terms of water regimes and habitat for wildlife. Both peat and non-peat wetlands absorb water from spring snowmelt and summer storms, reducing flooding, erosion and sedimentation and recharging the water table in times of drought. Wetlands are natural filters, cleansing the water that passes through them. All wetland types are habitat for a variety of plants and wildlife, including rare and endangered species. Similarly, peatlands play a vital ecological service, both as a filtration system for water and as a store of carbon. In Western Canada peatlands act as net carbon sinks.

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[293] Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 67.

[294] Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 68.

[295] Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 68.

[296] Alberta Energy and Utilities Board. 2004. *Shell Canada Limited Applications for an Oil Sands Mine, Bitumen Extraction Plant, Co-generation Plant, and Water Pipeline in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-009,* p. 68.

[297] Government of Alberta. 2005. *Mineable Oil Sands Strategy,* p. 4, http://www.energy.gov.ab.ca/docs/oilsands/pdfs/MOSS_Policy2005.pdf

Given the nature of oil sands mining operations, significant areas of land are drastically disturbed and efforts must be made to reclaim this land. The EPEA requires that oil sands operators reclaim land disturbed by their operations to an equivalent land capability that will support the intended end land uses on the reclaimed area.[298] Wetlands, and in particular peatlands, pose a unique reclamation challenge that has yet to be overcome. Peatlands removed by oil sands mine operators cannot be replaced after mine closure because they take thousands of years to naturally form, and because the characteristics of the post-mining landscape (e.g., changes in salinity) will not be conducive to their reestablishment.[299] In addition, currently planned oil sands mine reclamation will create a landscape with a greater proportion of dry, upland areas than existed prior to disturbance. In other words, there is projected to be a net loss of wetlands (not just peatlands). For example, CNRL's Horizon Project will result in the clearing of 5,676 ha of wetland communities. The total wetland area in the planned reclaimed landscape will be only 3,667 ha—a net loss of 2,009 ha of wetlands from the baseline. Since peatlands will be replaced by other types of wetland, the corresponding loss of peatlands will be 3,960 ha.[300] In light of this issue, research studies have been initiated within CONRAD to examine reclamation potential for peatlands.

While Alberta Environment has produced a guideline for wetland establishment, it does not prescribe the overall percentage, type or distribution of wetlands at a particular oil sands operation, leaving this to regulatory approvals.[301] In addition, the guideline contains only draft reclamation criteria as specific performance assessment criteria require further development.

In Alberta, a wetlands policy was being developed to address wetlands on public and private lands. The draft policy stated that, when development occurs on public lands, there must be no net loss of wetland area or function.[302] The Alberta Water Council has taken over the task of developing this policy.[303]

3.2.5.4 End pit Lakes

EPLs are currently planned to be a permanent feature of the post-mining reclaimed landscape, and are intended to serve multiple purposes (described in section 2.3.1.6). For example, the long retention time planned for EPLs will, in theory, allow for biodegradation of organic substances and dilution of water that has passed over or through the reclaimed landscape prior to draining into the lake. While operators have committed to ensuring that any discharges from the EPLs meet Alberta Surface Water Quality Guidelines or the guidelines in force at the time of release,[304] the feasibility of this commitment remains uncertain. Alberta Environment notes that, while the viability of EPLs as a sustainable ecosystem in the closure drainage landscape has yet to be

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[298] Alberta Environment. 2000. *Conservation and Reclamation Information Letter. C&R/IL/00-2. Guideline for Wetland Establishment on Reclaimed Oil Sands Leases*, http://www3.gov.ab.ca/env/protenf/landrec/documents/2000-2.pdf

[299] Alberta Environment. 2000. *Conservation and Reclamation Information Letter. C&R/IL/00-2. Guideline for Wetland Establishment on Reclaimed Oil Sands Leases,* http://www3.gov.ab.ca/env/protenf/landrec/documents/2000-2.pdf

[300] Canadian Natural Resources Ltd. 2002. *Horizon Oil Sands Project. Application for Approval,* Vol. 6, Section 4, p. 4-20.

[301] Alberta Environment. 2000. *Conservation and Reclamation Information Letter. C&R/IL/00-2. Guideline for Wetland Establishment on Reclaimed Oil Sands Leases,* http://www3.gov.ab.ca/env/protenf/landrec/documents/2000-2.pdf

[302] Alberta Environment. 2003. *Focus on Wetlands,* http://www3.gov.ab.ca/env/resedu/edu/focuson/wetlands.pdf

[303] Alberta Water Council. 2005. *Meeting #7 Summary Report,* http://www.waterforlife.gov.ab.ca/awc/docs/AWCSummaryReportMeeting7.pdf

[304] For example, see p. 65 of Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005.*

demonstrated,[305] some companies have already stated that these lakes will support viable, self-sustaining sport fish populations.[306]

3.3 Impacts of water use for in situ recovery

3.3.1 Types of impact

The demand for both fresh and saline water for the in situ recovery of bitumen is expected to increase over the next 15 years (see Figure 2-20). The environmental impacts associated with this use depend on a number of factors, which will be examined in this section. Later sections of this chapter look at the impacts in three regions where in situ recovery is being conducted.

The type and magnitude of the impacts from the withdrawal and treatment of water for the in situ recovery will vary, depending on a number of factors:

1. **The volume of water.** The volume of water required depends in most cases on the size of the project, although there are differences in the volume of water required to produce a unit of bitumen, depending on the recovery process used and how much of the water is recycled (see #4 below).
2. **The recovery process.** The impacts from CSS, which is used where the bitumen is deep, are different from those associated with SAGD. Imperial Oil has used the CSS process from the start of its developments in the Cold Lake area, and will continue using that process for its new Nabiye and Mahihkan North expansions.[307] CNRL uses CSS for its operations at Wolf Lake and Primrose, as does Shell for its Peace River operations. SAGD is being used for many new projects being developed in the Athabasca basin, where the bitumen is too deep to mine, but not deep enough for the CSS process to be used. It is also being used in two new projects in the Cold Lake area: Husky Energy's project at Tucker Lake and BlackRock's Orion project. Some impacts associated with these processes are described in the regional sections.
3. **The source water type.** The impacts depend on the type of water used—whether surface water or fresh or saline groundwater. The choice of source water will depend partly on geology.[308] If a company uses large volumes of fresh water, withdrawal may lead to a noticeable reduction in the groundwater level in that aquifer in the vicinity of the source well. If a company uses saline water, it may have to be treated before it can be used to generate steam. Such treatment will create waste products that must be disposed of in a landfill or deep disposal well.
4. **The water recycling rate.** The water recycling rate depends on the quantity and quality of the produced water (how much water stays in the reservoir, its salinity, etc.) and the

[305] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 65.

[306] Alberta Energy and Utilities Board. 2004. *Canadian Natural Resources Ltd. Application for an Oil Sands Mine, Bitumen Extraction Plant, and Bitumen Upgrading Plant in the Fort McMurray Area. Joint Panel Report. EUB Decision 2004-005,* p. 65.

[307] Imperial Oil Limited. 2004. *Imperial Oil Limited to make application for further expansion at Cold Lake,* http://www.imperialoil.ca/Canada-English/Files/News/CL_backgrounder_map. pdf

[308] The Husky Energy Tucker Lake SAGD project will use saline water, while the company's later Sunrise Project will use fresh groundwater from the basal McMurray aquifer. Husky Energy. 2004. *Sunrise Thermal Project Submission to the Alberta Energy and Utilities Board and Alberta Environment,* Vol. 1, p. 2-27 and 2-38.

water treatment process used. The recycle rate is also related to the type of extraction process used; with CSS as much as 95% of the produced water can be recycled.[309] There is considerable variation in the water recycling rate and the percentage of make-up water required for each project, shown in Table 3-1. The recycle figure in the table is based on the formula used by the EUB, which relates to the fresh (non-saline) rather than total water volume used.[310]

$$\text{EUB Recycle Rate (\%)} = \frac{\text{Steam injection volume} - \text{Non-saline volume}}{\text{Produced water volume}} \times 100$$

The EUB recycling rate is chosen to encourage companies to substitute saline for fresh water, and the EUB often specifies a minimum recycle rate in its approval for a project. The advantages of the EUB rate are that it

- does not penalize operators for losing water to the reservoir; it only holds them responsible for recycling as much produced water as possible.
- reflects the use of fresh (non-saline) water.

It is also useful to know how much make-up water a company requires. The make-up water rate is the percentage of new (fresh or saline) water that must be added to the produced and recycled water to generate steam for injection.[311] This reflects not only the volume of water left in the reservoir, but also the amount lost in recycling. Thus, for this report, we designed a make-up water rate:

$$\text{Make-up water rate (\%)} = \frac{\text{Make-up water volume}}{\text{Steam injection throughput}} \times 100$$

The extent to which produced water (water brought to the surface with the bitumen) is recycled clearly affects the volume of new make-up water required in the process.[312] The make-up volume of water can be used to calculate the water to bitumen ratio (the last column in Table 3-1). It can be seen that for in situ recovery the net loss is often about 0.2 to 0.3 units of water per unit volume of bitumen.[313] It is currently much higher at Shell's Peace River pilot operation where no water is recycled (see section 3.3.4) but no figures are available for water use for the planned expansion.

5. **Local geological conditions.** The nature of the geological formations affects the availability of both fresh and saline water and whether the withdrawal of this water is likely to have repercussions on adjacent zones. If there are good aquitards between zones,

[309] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 1, p. 2-13. In 2001 at the Imperial operations 95% of produced water was recycled and used for steam generation. Note: This is 95% of the water produced being brought back to the surface with the oil. Some water—approximately 9% in the Imperial case—remains in the formation. Make-up water refers to the volume of additional water required for each cycle. The Husky Energy Tucker Lake Project aims to recycle 90% of produced water. Husky Energy. 2003. *Tucker Thermal Project,* Vol. 1, p. 2-51, but, using the EUB formula, has a 100% recycle rate.

[310] The EUB is currently working on a revision of the formula given here.

[311] The make-up volume per unit of bitumen produced should not be confused with the steam:oil ratio. That ratio shows the total volume of water required to produce a unit of oil, without taking into account water losses in the formation, recycling process, and so on.

[312] The recycle rate and the make-up water rate do not usually add up to 100%, due to the different ways in which they are calculated.

[313] For reference to the water:bitumen ratio, see Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 39, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

the effects are likely to be minor, at least in the short term, but if the aquitards are thin or fractured, withdrawal of water may impact overlying formations. Geology may also determine which water treatment is used since, if there are no accessible formations for deep disposal wells, a waste treatment process will be used that creates solid waste for landfill.

6. **Cumulative effects.** Several projects in close proximity may have a cumulative effect on ground water. An EIA prepared to accompany an application for a project usually examines the effect of adjacent projects on water. While models may give some indication of what may happen, there is some uncertainty about the cumulative impacts of projects on groundwater in some areas.

Table 3-1 Projected water use, percentage fresh water, recycle rate and make-up water rate for major in situ projects in Alberta, 2005–2025

Project	Company	Process	Steam injection throughput (thousand m^3/year)	Fresh water as %age of total make-up water	EUB recycle rate %	Make-up water rate[314] %	Bitumen production (m^3/day)	Make-up water to bitumen ratio
Athabasca Region								
Christina Lake[315]	EnCana	SAGD	8,124	22	83–90	34	11,200	0.67
Firebag[316]	Suncor	SAGD	18,687	100	88	12	22,260	0.28
Hangingstone	JACOS	SAGD	1,825	100	92	16	1,750	0.45
Jackfish[317]	Devon Energy	SAGD	4,931	0	95	8	5,565	0.20
Joslyn Creek	Deer Creek	SAGD	4,183	100	98	8	4,295	0.20
Long Lake[318]	Opti/Nexen	SAGD	10,250	64	98	30	11,200	0.75
MacKay River[319]	Petro-Canada	SAGD	11,146	100	N/A	12	11,160	0.34
Meadow Creek[320]	Petro-Canada	SAGD	12,245	100	90	6	12,700	0.17
Sunrise	Husky Energy	SAGD	23,214	100	92	8	32,000	0.17

[314] The make-up water rate is the (Volume of make-up water/volume of steam injection throughput) x 100%.

[315]The detailed design for the project to be expanded to 11,200 m^3/day has not yet begun, so the volumes are estimates, based on extrapolation from the current phase 1B, which is for 3,200 m^3/day. EnCana plans to recycle all the produced water provided the volume is required for boiler feed water. Under normal operating conditions the water recycling rate is expected to be in the range given.

[316] Suncor's Firebag project uses water that is recycled from another facility, which was originally drawn from the Athabasca River.

[317] The recycle rate of 95% is that specified in the EUB approval for the Jackfish project.

[318] Water volumes for the Long Lake project include water use for the upgrader and co-generation plant, so are not directly comparable with other figures in the table. The figures provided are for Phase I. The water requirements for Phase II are not yet available.

[319] The figures for Petro-Canada's MacKay River facility reflect both the current operation and a proposed expansion, which has not yet been approved. The current project has not been assigned an EUB or Alberta Environment recycle requirement, but the application for the expansion reflects 90%.

[320] Petro-Canada's Meadow Creek project is on hold.

Surmont[321]	ConocoPhillips	SAGD	14,510	100	89	17	15,900	0.42
Whitesands	Whitesands Insitu Ltd.	THAI	22	—	—	—	300	0.00
Cold Lake Region								
Cold Lake[322]	Imperial Oil	CSS	36,552	71	100	12	30,000	0.48
Orion[323]	BlackRock Ventures	SAGD	3,383	0	—	3	3,089	0.08
Foster Creek[324]	EnCana	SAGD	14,509	33	90	30	At least 15,900	0.76
Tucker Lake	Husky Energy	SAGD	5,223	0	100	34	4,770	1.03
Wolf Lake/Primrose	CNRL	CSS	23,295	32	95	13	3,180	0.40
Peace River Region								
Peace River[325]	Shell	CSS	1,573	100	0	100	1,280	4.44

Data source: Individual companies[326]

Potential impacts will depend on the various factors listed above. Some may occur only at the local level, while others may affect a wider area. Some (such as the removal of water from the watershed or draw down of aquifers) are not unique to the oil industry. The impacts mentioned below have been discussed in various EIAs or in literature about the oil industry. They are listed here not in order of importance, but in the approximate order in which they may occur during the development of a project:

1. Removal of fresh water from the watershed;
2. Drawdown of fresh aquifers and changes in groundwater levels;
3. Mobilization of naturally occurring arsenic;
4. Contamination of fresh aquifers due to casing failures or seepage from the well bore;
5. Ground heaving and shrinking;
6. Depressurization of geological formations due to the removal of water;

[321] ConocoPhillips is exploring saline sources for use in Phase 1 or future phases of the Surmont project, so the percentage of saline water may change. The current design projection recycle rate for Phase 1 is 89%. The original EUB application cited 80% recycle. The recycle rate for Phase 2 has not yet been determined.

[322] At the time of writing, the EUB recycle rate gives a value of over 100%, since they do not count the use of saline water when calculating the recycle rate. The EUB is reworking their formula for the calculation of the recycle rate. The EUB recycle rate is given here as 100%, as with other companies that use saline water.

[323] The make-up water required is low due to new technology that will be used. Also, a review of historical data shows that, unlike other projects, the productive zone is contributing an amount of water, which is reducing losses to the formation.

[324] EnCana has an approval to produce up to 18,025 m^3 bitumen per day at its Foster Creek operations. Future water use is projected from current operations. EnCana plans to expand within the capacity of its current freshwater licences, by reducing the volume of fresh water relative to saline water, as it expands its operations.

[325] Figures are for current operations for 2004 only. Shell is planning an expansion at Peace River, but the water requirements for that project are not yet determined. Expected average water use from 2005 to 2025 is not available until water requirements for the expansion are determined. This may change the water:oil ratio, hence the query against that figure.

[326] All companies listed in this table were invited to verify the data in a draft prepared by the Pembina Institute. We have done our best to ensure that the information is comparable and accurate at the time of publication. However, as company plans develop, the numbers may change. We thus recommend that any information be confirmed before it is cited in other publications.

7. Voidage due to removal of bitumen;
8. Changes in the availability of saline water;
9. Waste water disposal in deep saline aquifers;
10. Landfilling of waste from water treatment processes.

Each of these impacts will be briefly examined.

1. **Removal of water from the watershed**. While the removal of water from the watershed is not unique to the oil industry, it is true that much of the water used for oil recovery does not return to the watershed.[327] Depending on the process used, some water may be left in the ground to replace the oil brought to the surface. Where this water is taken from surface sources or fresh groundwater, it is clearly being removed from the flow within the active water cycle of that watershed. The amount of water initially left underground after the bitumen is removed varies. The ratio for CSS is about 1 m^3 of water for every cubic metre of oil recovered.[328] Relatively little water is initially left in the ground in the SAGD process, but water will later infiltrate the zone to fill the void left by the oil (see #7, Voidage, below). Companies can reduce the removal of water from the watershed by using saline water and maximizing the recycling of produced water.
2. **Drawdown of fresh water aquifers.** The use of water in shallow, fresh aquifers for industrial purposes may affect the level of water in adjacent wells and surface waters.[329] Where a company is using fresh water, the risk of impacting other water wells may be reduced if water is drawn from the deepest freshwater aquifers, rather than from shallower ones. Monitoring of groundwater levels and surface water (in streams, lakes and wetlands) is essential to identify any impacts. To some extent shallow groundwater may be recharged by precipitation, but much precipitation flows across the surface to the streams and rivers. As a result "it is very difficult to measure natural groundwater recharge rates"[330] and so it will often be necessary to estimate them. Where water levels fall as a result of pumping, it is expected that they will recover once the pumping ceases, but it may take many years for an aquifer to recover. In the Surmont project it is estimated that the maximum impact on the fresh water Grand Rapid formation will be felt in 2043. The aquifer will begin to recover once pumping ceases; it is anticipated that by 2075 it will have recovered by 65%.[331]

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[327] The purpose of the *Advisory Committee on Water Use Practice and Policy,* which examined the use of water by the oil industry, was specifically to make recommendations "regarding practices that remove water from the hydrologic cycle." Terms of Reference, confirmed November 7, 2003.

[328] Hawkins, Blaine and Ashok Singhal. 2004. *Enhanced Oil Recovery Water Usage.* Alberta Research Council. Presentation to the Advisory Committee on Water Use Practice and Policy. March 2, 2004, http://www.waterforlife.gov.ab.ca/html/technical_reports.html

[329] Exploration Rio Alto Ltd. (now CNRL). 2002. *Kirby Project Application for Approval to Alberta Energy and Utilities Board and Alberta Environment,* Vol. 2, p. C2-16, provides a good summary of the potential impact of pumping: "When groundwater is pumped from a well, it causes a decrease in the pressure and water levels in the aquifer around the well. By decreasing the aquifer pressure, leakage from overlying strata will be induced. This induced leakage may in turn cause increased infiltration from wetlands, reduced discharge of groundwater to streams, lakes and wetlands, and the lowering of the water table. It is also noted that aquifer pumping will reduce the groundwater quantity in the aquifer, albeit on a temporary basis when the pumping is also temporary."

[330] ConocoPhillips. 2001. *Surmont Thermal Project Submission to the EUB and Alberta Environment Application and EIA,* Vol. 2, Part 3, p. 3-14.

[331] ConocoPhillips. 2001. *Surmont Thermal Project Submission to the EUB and Alberta Environment Application and EIA,* Vol. 2, Part 3, p. 3-81.

In some locations in northern Alberta, narrow buried glacial channels filled with unconsolidated sands and gravels cut into the bedrock. They may be less than a kilometre wide but up to 180 metres deep. They form good aquifers but, if the water is to be managed as a renewable resource, it is important to ensure that the withdrawal does not exceed the recharge rate (see section 3.3.3.2 on buried channels, below).[332] Due to the density of SAGD operations (as well as impacts from adjacent mining operations in some cases), the cumulative impacts on fresh aquifers must be evaluated. For example, the Surmont and Hangingstone projects are located in the same area. Surmont will draw its water from the Grand Rapids formation, while the Hangingstone project will draw its water from the overburden aquifer. The question arises: to what extent do the overburden aquifers help to recharge the Grand Rapids formation and what will be the cumulative impact of these operations?

3. **Mobilization of naturally occurring arsenic.** Elevated mineral levels can occur in the thermal plume around an injection well and these elevated levels may move away from the well site in the thermal plume. The naturally occurring level of arsenic in sedimentary rocks varies from one area to another,[333] but in some parts of the Cold Lake area thermal processes have increased arsenic levels in locations close to well bores (discussed in section 3.3.2.2 on Cold Lake, below).

4. **Contamination of fresh water aquifers due to leaks.**

   A. **Casing failures.** A casing failure can occur when the casing is not strong enough to withstand the build-up in pressure in the casing. Failures may occur at any depth in the casing, but those in the surface casing or at intermediate depths are of greatest concern due to the risk of a leak into a fresh aquifer. Casing failures have most frequently occurred in CSS after a number of injection cycles, when the repeated heating and cooling process has weakened the casing. A few casing failures resulted in aquifer or surface contamination, but since the mid-1990s casing failures usually have been detected during routine inspections, reducing the occurrence of environmental impacts.[334] While the stresses that result from the high temperatures and pressures associated with CSS are not likely to occur with SAGD, [335] casing failures may also occur at lower temperatures, due to sulphide stress cracking near the surface. Such failures might also occur with the SAGD process and SAGD (see section 3.3.2.2 on Cold Lake, below).

   Leakage from CSS is likely to be from the well into the aquifer, since the pressure of steam injection is higher than the aquifer pressure. In shallow SAGD

[332] Rates of recharge are very much influenced by the degree of hydraulic connection between aquifers and surface water (precipitation, lakes, streams). In some cases buried glacial aquifers have only a thin cover of low permeability sediment, and recharge can occur relatively rapidly. This is especially true where surface streams intersect the top of the aquifer, creating a high degree of hydraulic connection. However, if there is a thick permeable layer near the surface and little connectivity with other aquifers, recharge rates may be slow.

[333] Husky Energy. 2004. *Sunrise Thermal Project Submission to the EUB and Alberta Environment,* Vol. 2, Section 6.6.3.2. p. 6-36. There are naturally low arsenic concentrations in the groundwater where the Sunrise project will be developed.

[334] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 3, p. 4-51.See also section 3.3.2.2, below.

[335] SAGD is conducted at a pressure of approximately 3,200 kPA at 238°C and there are no temperature and pressure fluctuations, whereas for CSS, the pressure may be up to 12,000 kPA at 325°C during the steaming phase of CSS. Husky Energy. 2003. *Tucker Thermal Project Submission to the EUB and Alberta Environment,* Vol. 2, p. 3.2-64.

operations, pressures are less than or equal to those in the aquifer, which means that water would flow into the oil sand. This would drain water from the aquifer, but not cause contamination. A leak even a relatively short distance (e.g., ten metres) from a SAGD well may not develop until five to ten years after production starts, because the bitumen will seal it off, until the heat penetrates.[336]

Companies are required to report all casing failures so that Alberta Environment and the EUB can investigate and, where applicable, call for action to protect aquifers.

B. **Failure in caprock integrity.** The caprock that overlies the area of steam injection must be of sufficient strength and integrity to prevent any upward movement of steam or bitumen. This requires careful geological examination of the project area to identify any area where the caprock is unable to maintain the pressures and temperatures, either due to a thinning in the formation or erosion (e.g., by buried glacial channels) (see section 3.3.3.2, below). Caprock integrity is always investigated and confirmed in the EUB application review process. However, it cannot be proven prior to development, since seismic surveys do not identify features less than a few metres in size and core samples from wells may be hundreds of metres apart. Thus, even if the core shows a rock barrier, it may not be continuous (the core may be through an isolated rock slab or boulder) or it may be fractured in some places. When the steam gets to the top of a formation, permeability barriers may be compromised by the heat. A problem is more likely in shallow deposits, which are overlain by glacial till.[337]

5. **Ground heaving and shrinking.** The increase in pressure in the geological formation at the point of injection, which is necessary in the CSS process to fracture the formation and permit the migration of steam, leads to an increase in temperature and pressure in the steam chamber formations, as well as in overlying formations. This can lead to gradual, localized expansion and heaving at the surface. With SAGD the pressures used are below the formation fracture pressures, so ground heaving is either not expected or will be relatively minor—less than 0.5 metre.[338,339] While there may be some slight impact on surface drainage, the surface is expected to gradually subside as the formation temperature and pressure returns to ambient levels again.

6. **Depressurization of geological formations by the removal of water.** The withdrawal of water from a formation results in a reduction in aquifer pressure and increased rates of

[336] Bruce Peachey, personal communication, September 2005.

[337] SAGD is relatively new, so no fully developed chamber exists, but a SAGD project is likely to end when, a) the steam chamber is so big that the bitumen will no longer flow at a high enough rate to the drainage well; b) the chamber extends to an area without competent caprock and becomes unviable as water floods in or steam leaks out through the breach; c) there is a lack of balance between the injected and produced fluids or thermal expansion/contraction causes the overlying formation to flex and crack. Even in deeper conventional heavy oil wells in the Lloydminster area production usually ends with a sudden “flood” of water into the producing wells, which is thought to be due to the overburden giving way (since the wells in that area produce a lot of sand with the oil.) Several potential methods are being examined to prevent water or steam migration where the over- or under-burden is thin or to repair leaks. Bruce Peachey, personal communication, February 2006.

[338] ConocoPhillips. 2001. *Application for the Approval of the Surmont In-situ Oil Sands Project*, Vol. 2, Part 3, p. 3-11 states that ground heaving is not expected.

[339] Husky Energy. 2004. *Sunrise Thermal Project submission to the EUB and Alberta Environment,* Vol. 1, Section 4.0, p. 4-4 states that, “Physical expansion will be very gradual, localized and limit terrain swelling to less than 0.5 m, and no changes to groundwater flow patterns are anticipated.”

recharge. This is a concern where withdrawals of water from shallow saline aquifers lead to the infiltration of water from overlying fresh water aquifers. This situation occurs, for example, in the Cold Lake area where there is a thick sequence of glacial deposits. Withdrawals from one aquifer can be observed to affect adjacent aquifers. A “leaky” aquifer system occurs where glacial till forms aquitards between the aquifers; this till is more permeable than rock. In situations like this, the water chemistry of the aquifers is more similar than in a situation where they are separated by a competent/low permeability material.

7. **Voidage.** Voidage refers to the space created when oil or water that is removed is not fully replaced by another substance. The SAGD process requires all the fluid to be removed from the steam chamber to allow oil recovery, so very little oil is replaced by water during the production process. Once production ceases, it is almost certain that groundwater will gradually seep into this void. In reservoirs with a competent caprock (aquitard), the downward infiltration of groundwater will be limited. Much more water will move in laterally through the porous zone in a short time frame than vertically through a low permeability aquitard. However, since SAGD wells are usually less than 400 metres deep, if infiltration occurs it could have an impact on shallow groundwater. Although there are concerns about voidage make-up volumes, there is no data available to assess the issue. According to a recent report, “Historically the industry, in the Athabasca basin, has no firm basis for assessing the impact of incomplete voidage replacement on surface and shallow water aquifers . . . .”[340] In the Surmont project, it is anticipated that the ground may subside by 0.3 metre as a result of the removal of some of the groundwater. It may take more than 150 years for the rock to fully compress, “while the disturbances causing subsidence will last only approximately 30 to 50 years.”[341]

   The impact of each individual well is likely to be small, but given the large number of commercial SAGD projects that have been started or are planned, the potential cumulative impact when steaming stops and pressures are lowered needs attention.[342] Seepage of shallow groundwater into the voids created by the SAGD process could impact shallow groundwater levels until the affected aquifers are recharged and the water table stabilizes. Depending on the nature of the formation, there may be some settling and compaction, so the remaining void may not be as great as the volume of bitumen removed.[343] Voidage is less likely to be an issue with CSS since the process replaces 50–

[340] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 19, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[341] ConocoPhillips. 2001. *Application for the Approval of the Surmont In-situ Oil Sands Project,* Vol. 2, Part 3, p. 3-12.

[342] As Peachey says (op cit. footnote 18, Technical note), “Water use at conventional and thermal operations have historically all appeared to require approximately 1 m^3 of make-up water per m^3 of oil removed, however, where the water ends up and potential impacts with other water resources over the life of the project are different depending on the producing reservoirs and surrounding geology. Water sources (surface or groundwater), the producing zone, and water disposal zones may not be in direct flow communication with each other as unheated bitumen layers, shales, rock or other impermeable barriers will provide at least local isolation between zones. As a result it is necessary to consider water voidage balances independently for each zone affected by an operation. Wherever a voidage imbalance is generated (either by a net removal or a net addition of fluids) the imbalance will provide a new driving force to cause new sub-surface water flows. On a larger regional scale, some water bearing zones that are isolated in one local area may be hydraulically connected in some other area to allow interchange of fluids to restore an hydraulic balance, the existence of communication paths, and the rate of flows between zones cannot be anticipated until after a voidage imbalance is created.”

[343] Edo Nyland, Professor Emeritus, Physics, University of Alberta, personal communication, September 2005.

70% of the oil removed with water and, as CSS occurs in deeper formations, voidage is less likely to affect shallow groundwater (e.g., in the Cold Lake area, the bitumen-bearing formation is separated from fresh water by thick deposits of Colorado shales, which form an aquitard).

While the impact of voidage on fresh aquifers is of greatest concern, the removal of large volumes of deep saline water might also result in the long-term percolation of water from overlying fresh water aquifers. It is reasonable to expect that nearly 100% of the cumulative volume of bitumen removed will ultimately be replaced by groundwater (saline or fresh), and that the rate of infiltration of surface water will increase (usually by a very small amount) over a large surface area until the groundwater flow system returns to equilibrium (i.e., when the void created by the bitumen removal is replaced by water).

8. **Changes in the availability of saline water.** Due to concerns about potential impacts on fresh water sources, companies now try to use saline water where possible. The availability of saline water varies. In some areas there may be no geological formation containing the required volumes of saline water. Also, with increasing demands from many different companies, supplies of saline water may not be sufficient to meet all needs. One potential issue, identified by Imperial Oil, was the long-term supply of water in the saline McMurray formation: "Depending on the lateral extent and thickness of the McMurray Formation, and on attendant hydraulic characteristics, sustainability of this water resource is an issue both with respect to quantity and quality."[344] From subsequent work it seems that this is not a concern in the Cold Lake area as, "Results of industry models show that there is enough brackish water availability to supply long-term brackish water needs for current and proposed operations."[345] It seems likely the McMurray aquifer in the Cold Lake region could supply water for more than 50 years at current rates of diversion. However, since deep aquifers can take millennia to recharge, companies need to ensure that they do not exhaust the available supplies of saline groundwater. It is thus important to monitor this saline resource and adopt measures to ensure its sustainable use.

9. **Waste disposal impacts in deep saline aquifers.** Before saline water or recycled produced water can be used to generate steam, it must be treated to remove some of the minerals and any residual oil in the produced water. The resultant wastes are often put in deep disposal wells, which are usually drilled into a formation below the producing bitumen zone. The injection pressures are controlled to maintain them below the fracture pressure of the zone, but the net addition of fluids could lead to new subsurface pressures and flows.

   To protect groundwater, the EUB gives extra scrutiny to disposal schemes shallower than 600 metres; schemes in northeast Alberta are generally required to have additional monitoring in the disposal zone and next highest permeable zone to ensure scheme integrity.[346] However, although the AGS has a qualitative knowledge of the potential for

[344] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North submission to the EUB and Alberta Environment,* Vol. 3, Part 1, p. 4-14.

[345] Imperial Oil Limited, personal communication, January 2006, citing the Cold Lake-Beaver River State of the Basin Groundwater Quantity Report, December 2005 Draft.

[346] Alberta Energy Utilities Board, personal communication, February 2006. Disposal above the base of groundwater protection is not allowed.

each zone, and individual companies conduct their own assessments, "there has never been a systemic regional assessment of disposal capacity in the oil sand areas."[347] It is assumed that impermeable layers above and below the formation used for disposal will prevent migration but, as a geophysicist has pointed out, "We haven't measured how water migrates from one area to another. We don't understand the physics of what's going on . . . . There is no such thing as an impermeable layer. It's just that it takes longer for fluids to get through layers."[348] It is also possible for deep well injection to induce seismicity.[349] While this is most likely to occur in seismically unstable areas, rather than in sedimentary basins, it is important to ensure that injection pressures for deep well disposal do not exceed formation fracture pressures.

10. **Landfilling of waste from water treatment processes**. Water treatment processes may produce sludge or solid waste that can be transferred to a landfill. This not only requires dedicated landfill sites, but also poses the risk of leakage. Industrial landfills must be constructed with leachate collection systems and monitoring wells, but there is a potential that such sites might leak over the long term. (See also Waste Disposal in section 3.3.5.)

Some of the potential impacts identified above may not occur until after projects have been operating for a number of years, or until after they are shut down. Others have already occurred, especially in areas where CSS has been underway for some time. Examples are described, below, according to region. The section on Cold Lake is most detailed, since this area has a long history of in situ development and, until the recent development of SAGD, was the location of all commercial-scale projects.

3.3.2 In situ recovery in the Cold Lake Area

3.3.2.1 The sustainability of water resources in the Cold Lake area

In situ recovery of bitumen started in the Cold Lake area in northeastern Alberta, where Imperial Oil set up three pilot projects in the 1960s and 1970s, before expanding to commercial production in 1985. The operation, which is the largest in situ bitumen recovery project in Canada,[350] uses the CSS process, which first heats the formation containing the bitumen and then recovers the bitumen through the same well. This process initially requires very large volumes of water to generate the steam.

Water levels in Cold Lake and some other lakes in the region started falling in the 1980s, when industrial water withdrawals, including withdrawal of lake water, were severely compounded by drought. This led to the development of the Cold Lake–Beaver River Long Term Water

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[347] Peachey, Bruce. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 21, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[348] Edo Nyland, now Professor Emeritus, Physics, University of Alberta, quoted in Dennis Hryciuk. 1999. Doubts well up about deep-sixing waste. *Edmonton Journal,* October 17, p. E8.

[349] Healy, J. H., W.W. Rubey and D.T. Griggs. 1968. The Denver earthquakes. *Science,* Vol. 161, No. 3848, p. 1301–1310. A general overview of induced seismicity is given in Joel Sminchak, Neeraj Gupta, Charles Byrer and Perry Bergman. 2002. Issues related to seismic activity induced by the injection of CO_2 in deep saline aquifers. *Journal of Energy and Environmental Research,* Vol. 2, p. 32–46. The withdrawal of large volumes of water has also been known to induce seismicity, e.g., in the San Joaquin Valley in California.

[350] Imperial Oil Limited. 2004. *Imperial Oil Limited to Make Application for Further Expansion at Cold Lake,* http://www.imperialoil.ca/Canada-English/Files/News/CL_backgrounder_map. pdf

Management Plan, which was approved by the Alberta government in 1985.[351] The plan included limits on the withdrawal of water for consumptive purposes and set lake level elevations at which withdrawals from lakes were to be restricted or suspended. As a result Imperial Oil's Cold Lake project is allowed to use surface water when the Cold Lake level is above a specified elevation, but the company is also licensed to use groundwater when surface withdrawals are no longer permitted.[352] Thus, during the drought years 1992–1994, when the level of Cold Lake fell, withdrawals of groundwater increased, as can be seen in Figure 3-3. The actual water use is less than the allocation, but allocations have been increasing. Since 1985 total groundwater allocations in the Cold Lake–Beaver River area have increased about 50% to approximately 16 million m^3/year.[353] Three companies—CNRL (various projects), Imperial Oil (Cold Lake project) and EnCana (Foster Creek project)—have licences for the largest volumes.[354]

The Cold Lake–Beaver River management plan included a proposal to pipe water from the North Saskatchewan River into the basin. This solution was proposed again in 1994 but did not proceed, due to costs and concerns about inter-basin transfer and the fact that demand for water did not increase as rapidly as originally expected. Over the 30 years that it has been operating in the Cold Lake area, Imperial Oil has greatly increased bitumen production, using approximately the same volume of fresh water that it did in 1985, by improving the efficiency of its process, increasing recycling and using saline water. The company points out that "Improved water-reuse has reduced the amount of fresh water required to produce a cubic metre of bitumen from 3 m^3 in 1985 to less than 0.5 m^3 in 2001."[355]

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[351] Alberta Environment. 1985. *Cold Lake–Beaver River Long Term Water Management Plan.* A summary is available at http://www3.gov.ab.ca/env/water/Management/CLBR/pdf/1985plan.pdf

[352] Alberta Environment. 2006. *Cold Lake–Beaver River Basin Groundwater Quantity and Brackish Water State of the Basin Report.* Table 5-3, p. 49. This report was prepared in partnership with the Lakeland Industry Community Association and the Cold Lake–Beaver River Basin Advisory Committee. It provides a good overview of water resources in the basin.

[353] Alberta Environment. 2006. *Cold Lake–Beaver River Basin Groundwater Quantity and Brackish Water State of the Basin Report.* Table 5-1, p. 48.

[354] Alberta Environment. 2006. *Cold Lake–Beaver River Basin Groundwater Quantity and Brackish Water State of the Basin Report.* Table 5-3, p. 49.

[355] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 1, p. 2-26.

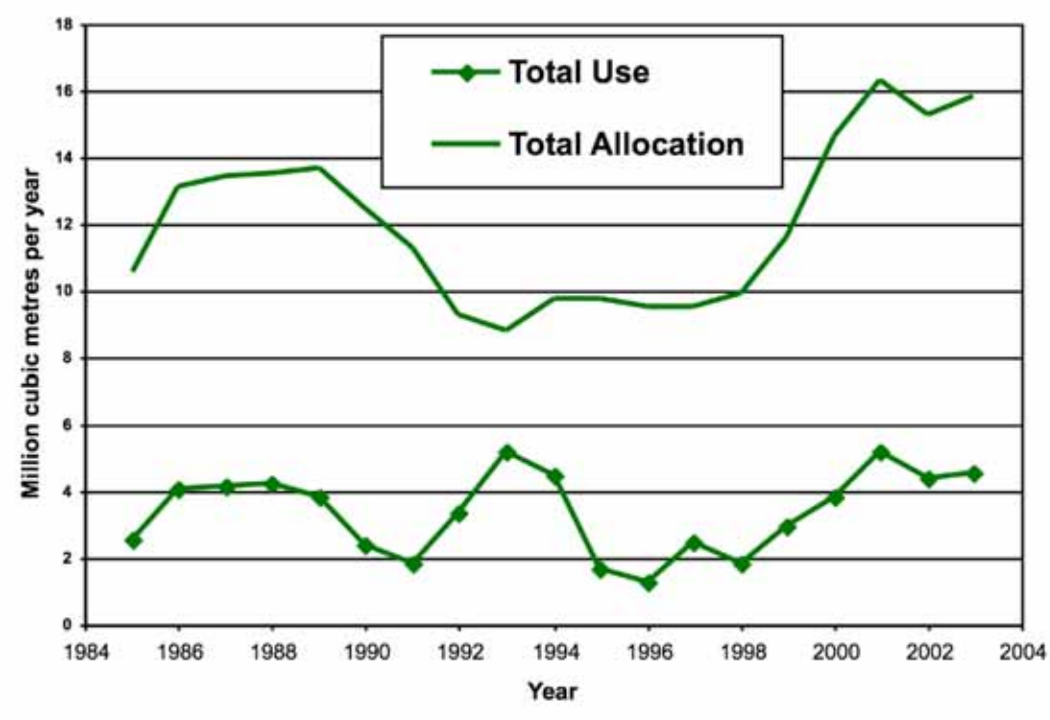

Figure 3-3 Comparison of fresh groundwater allocation and use in the Cold Lake–Beaver River Basin, 1985–2003

Data source: Alberta Environment

CNRL's use of fresh water is also expected to decline as the company uses more saline water. However, large volumes of water—both fresh and saline—will still be required. Allocations of water in the basin are nearing the limit set in 1985, so the Cold Lake–Beaver River Basin Management Plan is being updated.[356] One goal of the plan is groundwater sustainability. This has been defined as the "development and use of ground water in a manner that can be maintained for an indefinite time without causing unacceptable environmental, economic or social consequences."[357]

What have been the consequences of withdrawals so far?

The impacts of fresh groundwater diversions for projects in the Cold Lake area were reviewed in the Prairie Farm Rehabilitation Association's (PFRA) study of the M.D. of Bonnyville.[358] In the last 30 years more than ten EOR projects have been developed within the municipal district, with the larger projects having an impact on groundwater. Following an expansion of the Imperial Oil Cold Lake project, an adjacent monitoring network observation well (150 metres from the source well) showed a decline in groundwater levels for 34 months. After fluctuating by less than five metres between 1978 and late 1991, the water level fell by more than 50 metres following start

[356] Alberta Environment. 2003. *Planners Update: Cold Lake–Beaver River Water Management Plan,* http://www3.gov.ab.ca/env/water/Management/clbr/pdf/CLBR_update0903.pdf

[357] Alley, William M., Thomas E. Reilly and O. Lehn Franke. 1999. *Sustainability of Ground-Water Resources.* U.S. Geological Survey Circular 1186, p. 2, http://pubs.usgs.gov/products/books/circular.html

[358] Prairie Farm Rehabilitation Administration. 2002. *M.D. of Bonnyville: Part of the Churchill and North Saskatchewan River Basins, Parts of Tp 055 to 066, R 01 to 10, W4M, Regional Groundwater Assessment.* Prepared by Hydrogeological Consultants Ltd., p. 35–45 and p. A54–A55, http://www.10704.com/pdf/rgwa/bonnyville.pdf

up. The effect diminished at wells further from the project and the water level in the monitoring wells later recovered.[359] Likewise, following the start-up of the Amoco (now CNRL) Wolf Lake project, the level in the closest regional groundwater monitoring network well declined from 1985 until 1990. Water levels subsequently recovered but, as with the Imperial Oil project, did not rise quite to the original level. This may have been due to natural variability.[360]

Impacts from pumping are naturally greatest close to the diversion, and impacts from different pumping operations may overlap. For example, a five-metre reduction in one monitoring well in the Cold Lake region was attributed to production pumping 26 kilometres away.[361] Monitoring wells also show where there is interconnectivity between aquifers.[362]

It is premature to draw definitive conclusions. What impact does the long-term withdrawal of water from one of the deeper (fresh) aquifers have on other aquifers? It used to be thought that impacts were unlikely, since aquifers are separated by aquicludes, through which water moves only very slowly. This may be the case if aquifers and aquicludes form a "layer-cake" with no breaks in the aquiclude layers. However, recent work by the AGS indicates that there is some lateral and vertical connection between the formations, with sand lenses in till (clay) formations.[363]

In the Cold Lake–Beaver River Basin, as in much of northern Alberta, the solid bedrock is overlain by glacial deposits. Today's surface topography bears little relationship to the pre-glacial rock surface, and in some places glacial deposits are very deep where they fill pre-glacial buried valleys (e.g., the Helena Valley and Beverly Valley and their tributary valleys).[364] The glacial deposits include sands and gravels that form excellent aquifers, but much still needs to be learned about the flow of water into and out of the region along these buried valley aquifers.[365]

Surface waters are hydraulically connected to groundwater in glacial drift aquifers, which means that any pumping of groundwater from these aquifers could impact surface waters. An AGS study in the Cold Lake–Beaver River Basin indicates that groundwater development in drift aquifers could interact with surface water within five years of initiation of pumping.[366] Not only

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[359] In the EIA for its latest expansion, Imperial promised to ensure that "an adequate supply of water is available if residents are adversely affected by Imperial Oil's groundwater withdrawal." Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 3. Part 1, p. 4-29.

[360] Other wells in the region (but outside the influence of industrial pumping) experienced similar declines in the same time period. Imperial Oil Ltd., personal communication, January 2006.

[361] Canadian Natural Resources Limited. 2006. *Application for the Primrose East Expansion*. Hydrology Baseline Report, p. II-62. According to the report, "Water levels in the observation well located at 10-03-67-4WM measured prior to Canadian Natural McMurray production drop about 5 m between March 2003 and May 2004, due to production at the IOR pumping center located approximately 26 km away."

[362] Canadian Natural Resources Limited. 2006. *Application for the Primrose East Expansion*. Hydrology Baseline Report, p. II-67. Reporting with respect to water levels at the source well location at 10-66-5-W4, the report notes, "During periods of consistent and larger volume pumping, the water levels declined in the Muriel Lake Formaton and the Bonnyville Formation Unit 1 (sand and gravel) showing the connectivity of the Bonnyville Formation and underlying units."

[363] Andriashek. Laurence D. 2003. *Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Areas, Northeast Alberta*. Earth Sciences Report 2002-03, Alberta Energy and Utilities Board/Alberta Geological Survey, p. 82. See also, Alberta Environment. 2006. *Cold Lake–Beaver River Basin Groundwater Quantity and Brackish Water State of the Basin Report,* p. 69–70.

[364] Andriashek, Laurence D. and M.M. Fenton. 1989. *Quaternary Stratigraphy and Surficial Geology of the Sand River Area 73L*. Bulletin No. 57..Alberta Research Council, Alberta Geological Survey and Terrain Sciences Department.

[365] Parks, Kevin, Laurence D. Andriashek et al. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, Alberta Energy and Utilities Board/Alberta Geological Survey, p. 136.

[366] Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, p. ix.

can changes in groundwater affect surface water, but vice versa. Cold Lake and some other lakes are well-connected to aquifers and lake-level fluctuations are large enough to cause significant changes in aquifer levels. These connections will be at the local level, which means each sub-basin must be studied separately. There are five regional systems within the basin and at the local scale there is a complex system in which local groundwater recharge areas flow into lakes, small streams and wetlands, so it is impossible to generalize for the whole basin. Moreover, pumping can alter the natural boundaries of these flow systems and can pirate groundwater from one natural flow system to another.[367] The situation is further complicated by buried valleys and channels (see section 3.3.3.2).

Except during drought conditions, glacial drifts will be recharged from the surface by the downward percolation of precipitation or, in some cases, by direct flow from lakes or other surface water. If an aquifer is drawn down as a result of pumping, it may recharge within months or years, depending on the flow rates. At greater depths the rates of flow and recharge across different geological formations will be slow, and may be measured in centuries or millennia. Careful study is important to determine what rate of draw down is sustainable. A model developed by the AGS indicates that if all licensed groundwater users in the basin withdraw their full allocation on a continual basis, approximately 10% of the original steady-state water basin balance is being used.[368] Studies of the 24 active monitoring wells in the basin indicated that many of the wells are responding to pumping activity associated with bitumen or heavy oil production in the northeast part of the basin. Additional monitoring is needed to provide information on the movement of groundwater to and from lakes, to calculate groundwater recharge rates and to improve knowledge on the groundwater flows into and out of the basin along buried valley aquifers.[369]

Not only should the gaps in knowledge be reduced through improved monitoring at locations indicated by the AGS, but the results should be analyzed, using the model that the AGS developed, to determine whether water use in the basin is sustainable. If water-level declines are observed at these locations in excess of five metres, then it is likely that the maximum changes in recharge and discharge fluxes distributed across the basin as calculated by the model would be exceeded.[370]

As a result of efforts to reduce the demand for fresh water, the use of saline water for injection purposes in the Cold Lake area has increased. EnCana's Foster Creek Project uses water sourced from bedrock at a depth of 475 metres in the Grand Rapids formation, with a smaller amount from that formation being used by CNRL's Wolf Lake/Primrose project. Imperial Oil obtains its saline water from the McMurray formation, which underlies the zone that contains the bitumen. This is also the source for the Husky Energy Tucker Lake operation and the main source of saline water for CNRL. A study by Imperial Oil indicates the saline aquifer could produce over

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[367] Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, p. 77.

[368] Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, p. 116. The model excluded groundwater used for domestic and stock water, which is estimated to be less than 25% of the groundwater allocation in the basin.

[369] Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, p. 134, 136.

[370] Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74, p. 134, 146.

20,000 m^3/day of water for 50 years.[371] This is approximately the same as the estimated maximum long-term withdrawal.

Despite efforts to reduce the use of fresh water, much still needs to be done. As the AGS study points out,

> A key challenge for sustained use of ground water resources is to frame the hydrologic implications of various alternative development strategies in such a way that their long-term implications can be properly evaluated. Each hydrologic system and development situation is unique and requires an analysis adjusted to the nature of the water issues faced, including the social, economic and legal constraints that must be taken into account.[372]

3.3.2.2 Water quality in the Cold Lake region

Groundwater must be managed to protect not only the quantity of water in the aquifers, but also the quality. Members of the public have been concerned that the CSS process can affect the integrity of geologic formations. At the EUB hearing into Imperial Oil's application to expand its Mahkeses development at Cold Lake in 1999,[373] interveners argued that the unusual behaviour of water levels in Quaternary groundwater monitoring wells could be due to localized pressure increases that resulted from pressure leaks through fractures. They also considered that the CSS process may have caused minor seismic events. In its decision, the EUB noted "the significant number of previous casing failures"[374] but said that it was unclear what relationship, if any, the failures had on hydraulic isolation and well-bore integrity at locations away from the failure site. The EUB allowed the project to proceed, but set several important conditions: Imperial Oil was required to report annually on casing integrity, to implement an enhanced regional monitoring network at its existing operations and the proposed expansion area to monitor groundwater flow directions, to provide information on any water level responses to steam injection and to expand its research on seismicity in the area. Several other requirements in the EUB decision related to the impacts of Imperial's process on water quality, as set out in the next section. Finally, the EUB asked the company to establish a forum with other operators where concerns about the industry could be raised. This led to the establishment of the Lakeland Industry and Community Association (LICA), and the Regional Environmental Water Monitoring Committee (one of the committees set up by LICA).

In 1995, a casing failure of a well on Imperial's T-pad resulted in contamination of a freshwater aquifer with deeper saline water. This was remediated by pumping water from the aquifer until 2002, when the level of TDS and other contaminants returned to background levels. As casing failures tended to occur after eight or more repetitions of the steam cycle, Imperial Oil has implemented a monitoring program for well casings prior to steaming in the eighth to tenth

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[371] Alberta Environment. 2006. *Cold Lake–Beaver River Basin Groundwater Quantity and Brackish Water State of the Basin Report,* p.76.

[372] Alley, William M. and S.A. Leake. *Ground Water,* Vol. 42, No. 1, p. 16, cited in Alberta Energy and Utilities Board/Alberta Geological Survey. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta.* Special Report 74, p. 100.

[373] Alberta Energy and Utilities Board. 1999. *Decision 99-22. Imperial Resources Ltd. Application 970163 to Amend Approval No. 3950 Cold Lake Production Project. Mahkeses Development,* p. 25–32, http://www.eub.gov.ab.ca/bbs/documents/decisions/1999/d99-22.pdf

[374] Alberta Energy and Utilities Board. 1999. *Decision 99-22. Imperial Resources Ltd. Application 970163 to Amend Approval No. 3950 Cold Lake Production Project. Mahkeses Development,* p. 32, http://www.eub.gov.ab.ca/bbs/documents/decisions/1999/d99-22.pdf

cycles.[375] In their 2005 report to the EUB, Imperial Oil distinguishes between events that take place near the surface (0–25 metres), at intermediate depths (up to 420 metres in some places) and at the production zone, which is even deeper.[376] In 1996 a surface casing failure led to a surface release, but since then no environmental impacts have been reported at the surface, mainly due to early detection of failures as a result of the inspection program. There were no surface casing failures in 2004. Intermediate depth casing failures can result in the release of pressurized well fluids either directly or indirectly into potable drinking water zones. Since 1996, over two-thirds of the intermediate casing failures were identified in routine casing checks prior to a new steaming cycle, which enabled the casing to be repaired or taken out of service. Of the 156 intermediate casing failures reported, two (both in 1999) had a minor environmental impact. In 2004 there were over 50 casing failures at depths of more than 400 metres; these occurred where the CSS process causes stress and movement between the Clearwater formation (the production zone) and the overlying Grande Rapids formation. Although such failures affect the operation of the well, no environmental impacts have been identified from casing failures at these depths.

Since 1999, when CNRL took over the Wolf Lake and Primrose operations, 2,240 steam cycles have been conducted on more than 400 wells. There have been three casing failures, all below the depth of fresh groundwater.[377] CNRL has an extensive program for testing well integrity. As well as initially logging to check the integrity of the casing, 10% of wells are logged again after every three steam cycles. The records on mechanical deformation testing and pressure integrity testing are examined for 50% of wells in the “approval to steam” process for cycles five, six or seven. Prior to the eighth cycle, a corrosion assessment log is conducted on every well, as well as an evaluation of other records, to identify any concerns prior to steaming.

It is thought that the thermal activity associated with CSS may have caused the release of naturally occurring arsenic into the groundwater. The occurrence and movement of arsenic in groundwater is complex and not entirely understood to date, but Alberta Environment has required long-term study and monitoring of arsenic in groundwater in the Cold Lake area to improve understanding of the issue.

High arsenic levels occur naturally in many rocks and associated groundwater in northern Alberta.[378] This is a concern since, as Health Canada points out, “The International Agency for Research on Cancer considers arsenic a human carcinogen. Consuming drinking water that contains arsenic at levels close to or higher than the guideline value over a period of years has been found to increase the risk of skin cancer and tumours of the bladder, kidney, liver and lung.”[379]

A study of groundwater from domestic wells in the Lakeland Regional Health Authority area showed that, in 50% of raw water samples, the naturally occurring arsenic level exceeded 10 µg/l

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[375] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 1. p. 6-21.

[376] Imperial Oil Limited. 2005. *Annual Summary Report on Casing Integrity* submitted to the EUB, March 2005, p. 5–6.

[377] CNRL. 2005. *Application to Alberta Environment for Licence Renewal,* section 2.3 Well Integrity, Prevention, Detection and Remediation.

[378] Alberta Health and Wellness, Health Surveillance Branch. 2000. *Arsenic in Groundwater from Domestic Wells in Three Areas of Northern Alberta.*

[379] Health Canada. 2003. *Arsenic in Drinking Water,* http://www.hc-sc.gc.ca/english/iyh/environment/arsenic.html

(the current U.S. and World Health Organization maximum contaminant level for arsenic in drinking water); 21.9% of samples exceeded the Canadian maximum acceptable concentration of 25 µg/l.[380]

In its decision on Imperial Oil's application for its Mahkeses Development near Cold Lake, the EUB required the company "to address the potential that its operations may have on liberating or introducing arsenic into the groundwater."[381] This included setting up a monitoring program. Monitoring results, as well as laboratory tests, indicate that naturally occurring arsenic in aquifer sediments is released from a zone around the well bore as a result of the heat from the steaming process. Heating in the wellbore can increase the temperature in adjacent sediments; temperatures of up to 50°C have been found in water monitoring wells within 50 metres of a CSS operating pad, well in excess of the Canadian drinking water aesthetic objective of 15°C.[382]

In general it was thought that, although the heat associated with the CSS process mobilized the arsenic adjacent to the well bore, levels were close to background readings 300 to 400 metres away from the heated wellbore.[383] However, it has been discovered that the longer heating occurs, the greater the distance over which deposits may be warmed. In January 2003, the groundwater temperature about 400 metres down gradient from a well pad that started steaming in 1990 was about 16°C. This bears out the results of the heat and fluid flow modeling in which "Imperial Oil has shown that groundwater temperatures may be 10 to 15°C above background up to 600 metres from the CSS pad after many years of CSS steaming."[384]

These higher temperatures are one way in which arsenic may be released to the groundwater. Laboratory experiments conducted by Imperial Oil confirm that arsenic is released from sediments when sediment/water samples are heated from 50 to 200°C, with the rate of arsenic release increasing with increasing temperature.[385] At one Muriel Lake monitoring well that was at the edge of a heated groundwater plume about 400 metres down gradient from a CSS well pad, Imperial Oil found the temperature was 7°C higher than the background temperature and the arsenic concentration was also approximately three times higher. Imperial Oil notes that the release of arsenic stops once steaming operations cease, but the arsenic slowly migrates in the direction of groundwater flow. Field study is underway to determine how the arsenic disperses in

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[380] Alberta Health and Wellness, Health Surveillance Branch. 2000. *Arsenic in Groundwater from Domestic Wells in Three Areas of Northern Alberta,* p. 11, Table 3, http://www.health.gov.ab.ca/resources/publications/ArsenicGroundwater.pdf

Health Canada. 2006. *Guidelines for Canadian Drinking Water Quality – Summary Table.* Although the current maximum contaminant level for arsenic is 25 ug/l, a new maximum acceptable concentration of 5 ug/l is being proposed. See Table 3, http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/doc_sup-appui/sum_guide-res_recom/index_e.html This is the same level as that for protecting aquatic life.

[381] Alberta Energy and Utilities Board. 1999. *Decision 99-22. Imperial Resources Ltd. Application 970163 to Amend Approval No. 3950 Cold Lake Production Project. Mahkeses Development,* http://www.eub.gov.ab.ca/bbs/documents/decisions/1999/d99-22.pdf One of the issues addressed was whether groundwater withdrawals might mobilize arsenic found naturally in Quaternary sediments. Research showed that pumping had no effect on dissolved arsenic concentrations in groundwater. Imperial Oil Resources. 2005. *Fact Sheet: Cold Lake Groundwater Arsenic Study.*

[382] Imperial Oil Limited. 2002. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Submission to the EUB and Alberta Environment,* Vol. 3, Part 1. p. 4-54.

[383] Alberta Energy and Utilities Board. 2004. *Decision 2004-089. BlackRock Ventures Inc. Application for a Steam-Assisted Gravity Drainage Project for the Recovery of Bitumen. Cold Lake Oil Sands Area,* p. 6, http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-089.pdf

[384] Imperial Oil Limited. 2003. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Additional Supplemental Information Update*, p. 4-60.

[385] Imperial Oil Limited. 2003. *Cold Lake Expansion Projects: Nabiye and Mahihkan North Additional Supplemental Information Update,* p. 4-60.

the aquifers and whether or to what extent it is later re-adsorbed. Since groundwater moves slowly, this field study will continue for many years.

BlackRock's EIA for its Orion project noted that the water wells used by several area residents were within 400 metres of its proposed operations. At the EUB hearing into the project, Dr. J. Nriagu, an expert on arsenic who was engaged by local landowners, identified several mechanisms by which the project could release arsenic into the groundwater.[386] He drew attention to the 24 casing failures that had occurred in Township 64 in which the BlackRock project is located. Most of these were associated with recovery using the CSS process, but Dr. Nriagu pointed out that casing failures cannot be discounted in any high temperature and pressure oil recovery process, which would include SAGD. BlackRock indicated that arsenic concentrations may rise in the thermal plume, as a result of heat, but said that the process would be reversed as the plume cools.

Dr. Nriagu, speaking in general terms about arsenic, suggested that the process is not reversible and, depending on the hydraulic gradient and the physical–chemical characteristics of the aquifer, the arsenic plume around the injection wells could be transported well beyond the heated zone. In his opinion, "increased arsenic concentrations in well water, due to thermal-affected process in the Lease Area, represent a significant health risk to local residents."[387] He also drew attention to the potential that contaminated groundwater might affect Ethel Lake, which is partly fed by groundwater. Dr. Nriagu recommended long-term monitoring to obtain temporal and spatial data that would allow any impacts on arsenic levels to be identified. In its decision, the EUB indicated that the BlackRock monitoring program must be designed to gather project-specific information related to thermal arsenic mobilization and transport.[388]Husky Energy will also be using the SAGD process to extract bitumen at their Tucker Lake project in this region. Although casing failures are not expected to be a problem, recent SAGD applications to the EUB examine the potential for elevated levels of arsenic and propose monitoring to identify any problems.[389]

3.3.3 In situ recovery in the Athabasca Region

3.3.3.1 Water demand and supply

Within the Athabasca River Basin lie not only the mining projects around Ft. McMurray but also an increasing number of SAGD projects. Almost all SAGD projects in the region use some fresh groundwater, although some mix it with saline groundwater (Table 2-3). Devon Energy's Jackfish project uses all saline water. Suncor's Firebag project uses water transferred from its base facility at the Steepbank Mine, which originally came from the Athabasca River, so does not withdraw any groundwater. Even though every company in the region using the SAGD

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[386] Nriagu, Jerome. 2004. *Concerns about the Health Effects of Arsenic in Groundwater in Cold Lake Area, Alberta.* Presentation to the EUB at the Black Rock hearing. Dr. Nriagu is Professor and Director, Environmental Health Program, Department of Environmental Health Sciences, School of Public Health, University of Michigan.

[387] Nriagu, Jerome. 2004. *Concerns about the Health Effects of Arsenic in Groundwater in Cold Lake Area, Alberta.* Presentation to the EUB at the Black Rock hearing, p. 8.

[388] Alberta Energy and Utilities Board. 2004. *Decision 2004-089. BlackRock Ventures Inc. Application for a Steam-Assisted Gravity Drainage Project for the Recovery of Bitumen. Cold Lake Oil Sands Area.* p. 6–7, http://www.eub.gov.ab.ca/bbs/documents/decisions/2004/2004-089.pdf

[389] Husky Energy. 2003. *Submission to the EUB and Alberta Environment for the Tucker Thermal Project,* Vol. 2, Section 3.2-71 and following. The EIA provides a good overview of issues relating to arsenic.

process recycles the water it uses, large volumes of make-up water will be required for several decades. Although each company conducts an EIA to estimate the potential impact of its water use when it makes its project application, there is insufficient information to evaluate the cumulative impacts on groundwater from a large number of projects in the region. Moreover, new information is still being gained about the geology of the area, especially with respect to buried channels.

3.3.3.2 Buried valleys and channels

The rapid development of SAGD in northeast Alberta means that it is essential that Alberta Environment improve its understanding of the water resources in the area, to ensure that they are used in a sustainable manner. Pre-glacial buried valleys, already mentioned in the Cold Lake area, are found throughout northeastern Alberta, sometimes containing more than 300 metres of glacial deposits.[390] The extent of these buried valleys is seen in Figure 3-4, which shows bedrock topography for northeastern Alberta. There is often no relation between the bedrock topography and the surface topography, as can be seen by comparing Figures 3-4 and 3-5.

[390] Andriashek, L.D. 2003. *Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Area, Northeast Alberta.* Earth Sciences Report 2002-03, Alberta Energy and Utilities Board/Alberta Geological Survey, p. 24.

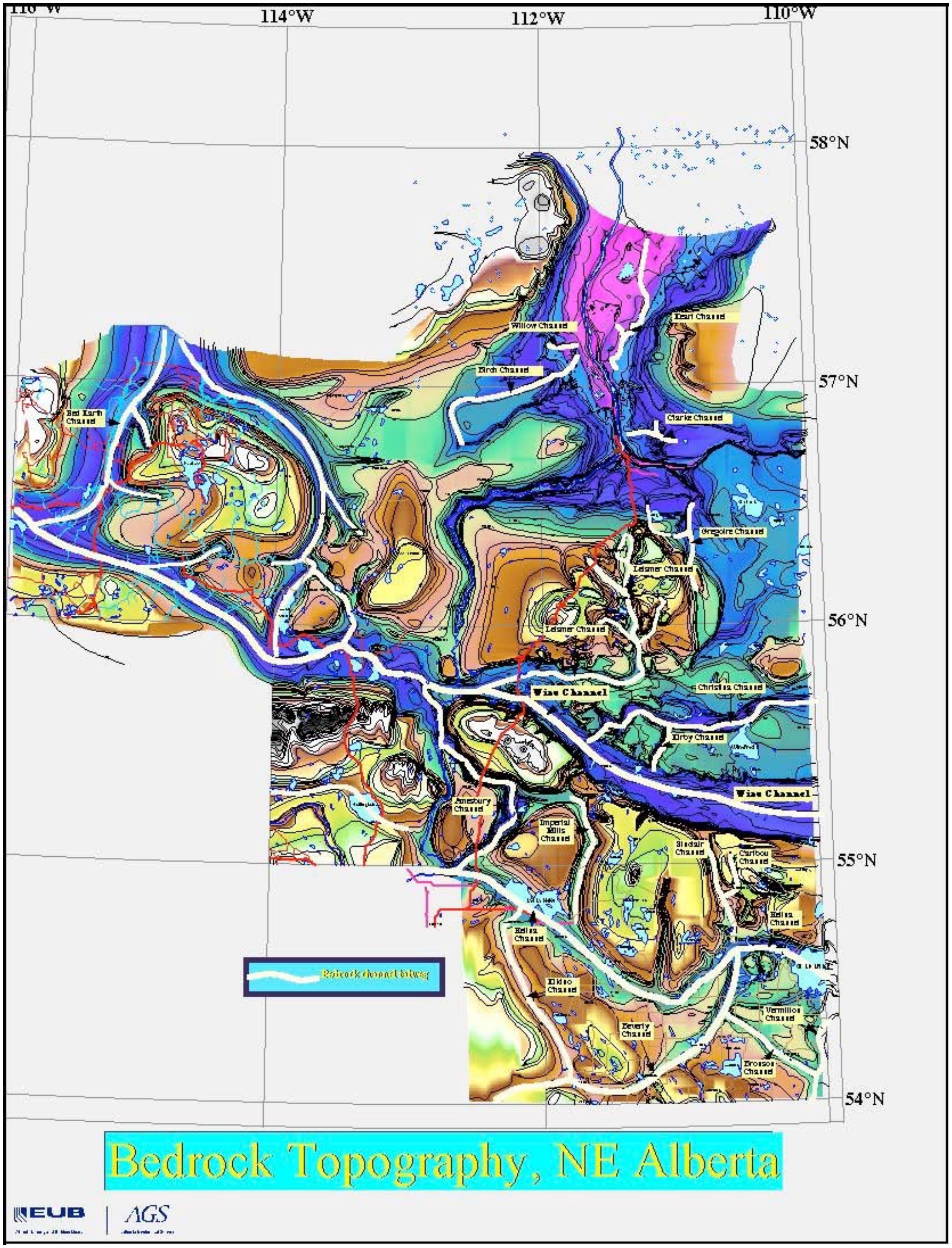

Figure 3-4 Bedrock topography in northeast Alberta, showing buried valleys and channels

Source: Alberta Geological Survey, with permission

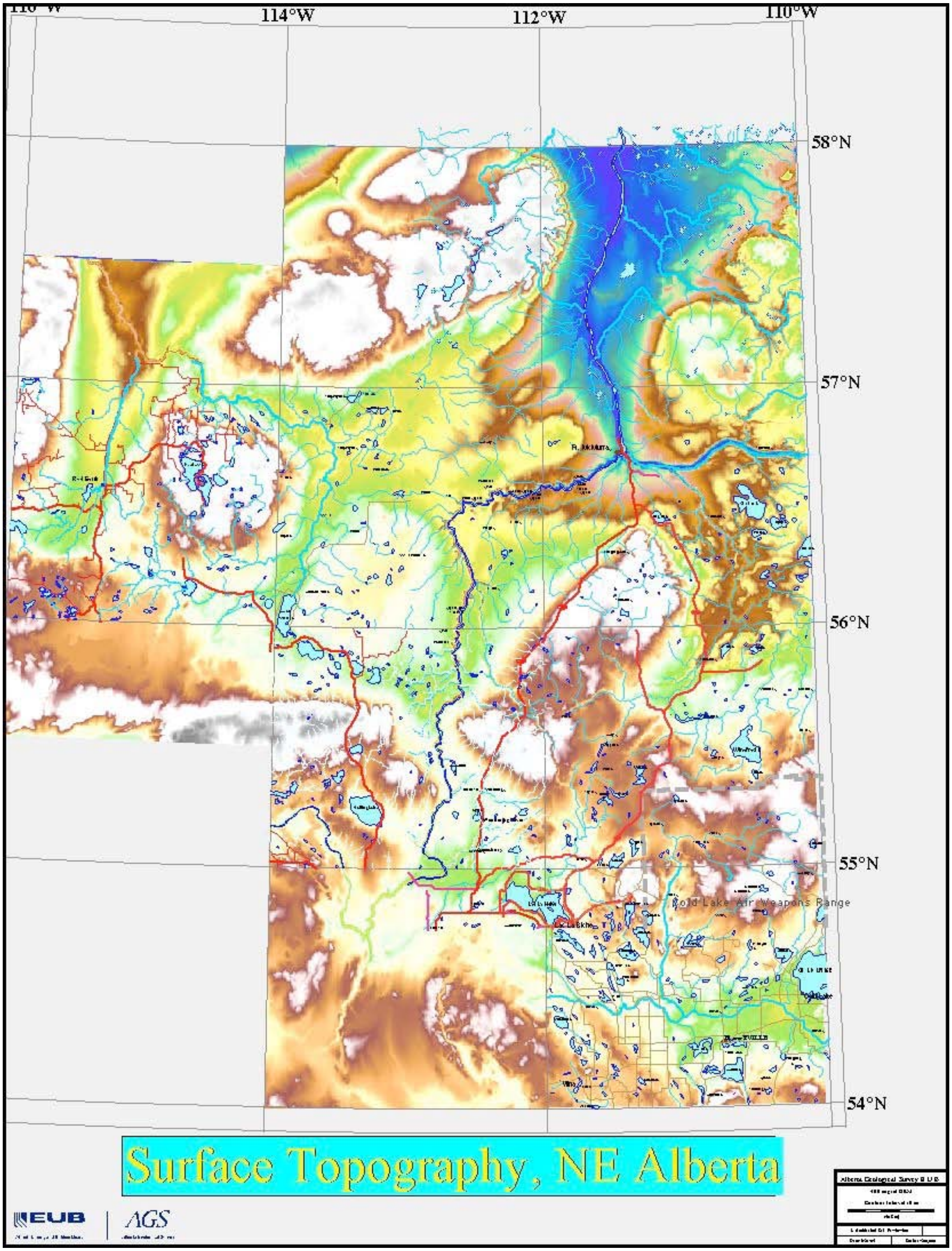

Figure 3-5 Surface topography in northeast Alberta

Source: Alberta Geological Survey, with permission

The deposits covering the bedrock include extensive sands and gravels that provide aquifers. One valley, referred to as the Wiau Channel, extends for nearly 200 kilometres and is 25 to 30 kilometres wide where it crosses the border into Saskatchewan.[391]

The region is also crossed by a number of buried glacial channels, which were formed by melt water during one of a number of glaciations that are believed to have covered the region. The glacial channels may be only a kilometre wide but up to 180 metres deep, and, being filled with unconsolidated sands and gravels under a thin capping of till, they form excellent aquifers. They include the Birch, Willow, Kearl, Clarke and Gregoire channels.[392] Since the channels are filled with glacial sediments, which mask them on the surface, and are usually unrelated to the broader system of buried valleys, it is difficult to identify their location. New channels are still being found and mapped, both by the AGS and by companies conducting detailed geological surveys of their lease sites, prior to locating their wells. These glacial channels are of great significance with respect to the water requirements as they provide important water reservoirs. The Birch Channel west of Ft. McMurray provides water for Petro-Canada's MacKay River SAGD project as well as for the Dover project (formerly the Alberta Oil Sands Technology and Research Authority (AOSTRA) Underground Test Facility).[393]

However, due to their limited surface area, relative to their depth, it is essential to ensure that water use does not exceed the rate of recharge. For example, the MacKay River EIA examines whether the "use of groundwater from the Birch Channel Aquifer as a source of water supply for the MacKay River facility will reduce available groundwater resources and affect other users."[394] The EIA estimates that the recharge from the west will exceed the amount used, but indicates that monitoring will be necessary to determine whether this estimate is correct.[395]

Glacial channels may cut into oil sands. Careful geophysical exploration of conditions above proposed SAGD operations is necessary to ensure the integrity of the shale cap rock above SAGD steam chambers, to avoid leaks and the potential for migration of the oil into potable aquifers.[396]

3.3.3.3 The sustainability of water resources in the Athabasca Region

Whereas it was possible to identify impacts from water withdrawal in the Cold Lake region, this is not yet possible for SAGD projects in the Athabasca Basin, since development is recent. However, as water is pumped from an aquifer, it may affect surface water or other aquifers.

Earlier in this chapter it was noted that the Surmont and Hangingstone projects are located in the same area. A question was posed with respect to the use of water from the overburden (for the

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[391] Andriashek, L.D. 2003. *Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Area, Northeast Alberta.* Earth Sciences Report 2002-03, Alberta Energy and Utilities Board/Alberta Geological Survey, p. 24.

[392] Andriashek, L.D. 2001. *Quaternary Stratigraphy of the Buried Birch and Willow Bedrock Channels, NE Alberta.* Earth Sciences Report 2000-15, Alberta Energy and Utilities Board/Alberta Geological Survey, p. 22.

[393] In 1983 AOSTRA developed designed an Underground Test Facility (UTF) project and the development of in situ techniques and strategies for accessing oil sands reserves that are too deep for surface mining. Starting in 1987, the SAGD process was field-tested at the UTF before it was developed by commercial operators, http://collections.ic.gc.ca/oil/litrdd.htm

[394] Petro-Canada. 1998. *Application for Commercial Approval of the MacKay River Project.* Vol. 3, 5-1.

[395] Petro-Canada is examining the potential to use VAPEX, a new solvent process, which could reduce the use of water for the MacKay facility.

[396] EUB/AGS. 2003. *Quaternary Geological Setting of the Athabasca Oil Sands (In Situ) Area, Northeast Alberta.* Earth Sciences Report 2002-03, p. 84.

Hangingstone project) reducing the recharge of the Grand Rapids formation that supplies the Surmont project. Another question worth asking is, What is the probability that pumping from the Grand Rapids formation for the Surmont project will induce leakage from the overburden layers?

The extent of surface impacts will depend on the rate of pumping relative to the recharge rates. Will the withdrawals from the Birch Channel be sustainable over the life of the Petro-Canada MacKay River project and any other development that draws on that water?

To find answers to questions such as these, a regional groundwater monitoring plan is being proposed for the SAGD projects south of Ft. McMurray.[397] The Regional Aquatics Monitoring Program (RAMP) has set up a groundwater advisory group within its technical group to assess options for the management of regional groundwater monitoring.

Not only do many in situ projects affect each other, there will be cumulative impacts associated with mining operations. Sometimes projects will be complementary. In the case of Husky Energy's Sunrise project, the company currently plans to use water from the basal McMurray aquifer from locations on Imperial Oil's lease that would otherwise be depressurized by Imperial Oil as part of their Kearl Mine project.[398] However, this does not mean there will not be impacts on the regional aquifers.

3.3.4 The Peace River area

Shell has been using the CSS process to extract bitumen in an area northeast of the Town of Peace River since 1979, using water initially from Cadotte Lake but now from the Peace River. Despite the long operating life, the project is currently still a pilot at demonstration scale. Due to the relatively small scale of the project, easy access to an abundant water source, lack of development pressure on the Peace River, and the company's assessment of net environmental benefits, Shell does not currently recycle any water.[399] Shell has announced plans to expand its operation; although the proposed commercial development, the Carmon Creek project, would increase the current licensed limit by 150%, any increase in fresh water requirements can be met from the company's existing licence.[400]

As well as using CSS, Shell has tried other well designs, including SAGD in 1996 and 1997. More recently the company has developed a horizontal cyclic steam (HCS) technology, which modifies the CSS process by developing horizontal wells. Up to 20 wells can be drilled from a single well pad, with each well extending laterally through the bitumen. The SAGD wells have been converted to the HCS process.[401]

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[397] The Regional Groundwater Monitoring Plan for SAGD projects south of Ft. McMurray is still being developed, but would be supervised by a multistakeholder group similar to the one operating in the Cold Lake region under the auspices of the Lakeland Industry Community Association. Peter Koning, ConocoPhillips, personal communication, August 10, 2005.

[398] Husky Energy, personal communication, February 2006.

[399] Shell Canada. Various dates. *Peace River Complex News,* including Disclosure Document for the Proposed Shell Canada Limited Peace River Oil Sands Carmon Creek Project. This description of a new project at Carmon Creek also includes a brief history of the existing operation. The Carmon Creek project would increase bitumen production to approximately 5,000 m^3/d, http://www.shell.ca/peaceriver

[400] Shell Canada. Various dates. *Peace River Complex News*, including Disclosure Document for the Proposed Shell Canada Limited Peace River Oil Sands Carmon Creek Project, section 2.2 Project Description, http://www.shell.ca/peaceriver The current licences allow for withdrawal of 4,317,000 m^3 (3,500 acre-feet) per year from the Peace River.

[401] Shell Canada. 2005. Seismic and drilling update. *Peace River Complex Newsletter,* Winter 2005, http://www.shell.ca/peaceriver

Like Imperial Oil, Shell had some casing failures in its earlier vertical CSS, but all the affected wells have been abandoned. Of the 25 confirmed casing failures, three were at depths between 200 and 350 metres, potentially in the fresh groundwater zone. Groundwater monitoring wells have been installed around existing production well pads to monitor for leaks. Since 2000, well casings have been modified and no further casing problems or failures have been detected.[402]

BlackRock Ventures Inc. also extracts heavy oil in the Peace River area at Seal. Prior to BlackRock's exploration, which started in 1999, it was thought that thermal recovery would be necessary to extract the oil. The company found, however, that some oil is mobile enough to produce using horizontal wells and conventional primary recovery methods. After primary production, water flooding or a thermal process will be used to increase the recovery of oil.[403]

3.3.5 Waste disposal from water treatment for in situ operations

The main waste from in situ bitumen extraction results from water treatment processes. If saline water is used, it may be necessary to reduce its salinity before using it to generate steam (see Chapter 4). Produced water must also be treated prior to recycling. The wastes from desalinization and other treatment processes may be injected into disposal wells in deep formations, usually underlying the bitumen, and the impermeable salt beds in the Elk Point Group (where the salt beds are present), or they may be landfilled. Whether a company uses deep well disposal or landfill will depend on the water treatment process selected. This, in turn, depends partly on local conditions, such as the proximity to a geological formation suitable for deep well disposal. In the Fort McMurray area deeply buried formations suitable for wastewater disposal are not readily available.

Different jurisdictions have different regulations with respect to disposal wells. This may be partly due to geological conditions and partly due to previous experience. In Ontario, where suitable geological formations are limited, deep well disposal for any substance except brine has been banned since the 1970s.The EUB considers that deep well disposal is a safe and viable disposal option if the wells are properly constructed, operated and monitored.[404] This includes ensuring that the rate and pressure of injection is carefully monitored to ensure it does not exceed the formation fracture pressures. Monitoring is also essential to ensure the wastes do not move in a direction that could impact usable water resources, as has been recorded in the U.S.[405]

Some water treatment processes produce sludge or solid wastes that can be landfilled. In some cases a company may use a combination of processes that results in both deep well disposal and landfilling (see Table 3-3). The wastes may include spent lime sludges (e.g., Petro-Canada's Meadow Creek project and Imperial Oil's Cold Lake project) or they may be in a more solid form. Several new water treatment processes are being developed that produce a solid waste for

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[402] Meera Nathwani, Sustainable Development Coordinator, Peace River, Shell Canada Ltd., personal communication, August 2, 2005.

[403] BlackRock Ventures Inc. 2004. *Seal, Alberta,* http://www.blackrock-ven.com/seal.html

[404] Alberta Energy and Utilities Board. 1994. *Injection and Disposal Wells: Well Classifications, Completions, Logging and Testing Requirements,* p. 5.

[405] Wilson, E.J., T.L. Johnson, and D.W. Keith. 2003. Regulating the ultimate sink: Managing the risks of geologic CO_2 storage. *Environmental Science and Technology,* Vol. 37, No. 16, p. 3481, reports a personal communication with R. Deurling, Florida Department of Environmental Protection, indicating that, "Injected wastewater has been found in monitoring wells of USDW's [underground sources of drinking water] above the injection zone at three sites thus far, indicating injected waters have migrated from the injection zone."

landfill, rather than a sludge. Deer Creek's Joslyn project will use an evaporator and crystallizer process.[406]

Whether a company uses deep well disposal or landfill to deal with waste from water treatment may depend on the suitability of local formations for deep well injection. While Petro-Canada's Meadow Creek project sends some wastes to deep well injection, its MacKay River project recycles water using an evaporator system and landfills the resultant solid brine waste.

Although the zero liquid discharge process allows nearly 100% water recycling, it has large landfill requirements for the waste salts produced by the water treatment process. Alberta Environment sets out the requirements for salt disposal in landfills, usually calling for a class II industrial landfill.[407] To minimize the risk of leaks, landfills must be constructed with a leachate collection system. The leachate can be recovered and, depending on its composition, be sent for deep well disposal or treated and used as recycled water, as is being proposed for Devon's Jackfish project.[408]

Both deep well disposal and landfilling solid waste can have harmful impacts, which include the potential for salts to leach into fresh water aquifers. A recent publication reports,

> "While injecting concentrates into disposal wells probably has the least environmental impact, disposing concentrates and effluent sludge in landfills could have significant environmental and ecological impact on the nearby soil and groundwater due to the high concentration of acids, hydrocarbon residues, trace metals and other contaminants.[409]

The leachate from landfills must be pumped out to ensure it does not leak into the underlying soils. The risk of leakage will depend in part on the level of groundwater. If the water table is high, the breakdown of materials may be slower, due to the anaerobic conditions. Where the water table is low, the waste may react with oxygen to produce the precursors of leachate; these contaminants can then move through the waste zone if the water table later rises or if precipitation flows through the area. In such circumstances, the volume of leachate may be low, but the concentration of contaminants could be high. A fluctuating water table is likely to create the worst conditions; during high water conditions, the water will pick up and transport contaminants generated when the water table was low. Ongoing pumping and monitoring may be needed for years after a landfill is capped and closed, to minimize the risk of leaks into groundwater and soils.

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[406] Heins, Bill and Dan Peterson. 2005. Use of evaporation for heavy oil produced water treatment. *Journal of Canadian Petroleum Technology*, Jan. 2005, Vol. 44, No.1, p. 26–30, http://www.deercreekenergy.com/presentations/tech_pres.html

[407] Alberta Environment. 1996. *Waste Control Regulation, section 1(j)* defines class II landfills as landfills that are not allowed to accept hazardous waste. Landfills that accept less than 10,000 tonnes of non-hazardous waste a year must comply with the *Code of Practice for Landfills* while those that accept more than this require an approval.

[408] Devon Energy Ltd., personal communication, July 2005.

[409] Hum, Florence, Peter Tsang, Thomas Harding and Apostolos Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy, University of Calgary, p. 29.

Table 3-2 Projected waste disposal at major in situ projects in Alberta, 2005–2025

Project	Company	Process	Deep well disposal (m^3/year)	Landfill (tonnes/year)
Athabasca Region				
Christina Lake[410]	EnCana	SAGD	2,400,000	6,247
Firebag[411]	Suncor	SAGD	2,235,100	7000
Hangingstone[412]	JACOS	SAGD	39,000	3,500
Jackfish[413]	Devon Energy	SAGD	372,100	300
Joslyn Creek	Deer Creek	SAGD	0	8,700
Long Lake[414]	Opti/Nexen	SAGD	1,743,200	0
MacKay River[415]	Petro-Canada	SAGD	102,200	32,200
Meadow Creek[416]	Petro-Canada	SAGD	105,900	23,700
Sunrise	Husky Energy	SAGD	1,896,200	0
Surmont[417]	ConocoPhillips	SAGD	Reducing from 2.4 million to 0 by 2017	17,520
Whitesands	Whitesands Insitu	THAI	43,800	0
Cold Lake Region				
Cold Lake[418]	Imperial Oil	CSS	369,000	37,300
Foster Creek[419]	EnCana	SAGD	4,341,000	12,900
Orion	BlackRock Ventures	SAGD	130,000	0
Tucker Lake	Husky Energy	SAGD	1,558,000	0

410 Detailed design of production for full operation of 11,200 m^3 bitumen per day has not begun, thus volumes for disposal are estimates based on extrapolation from current phase 1B, which produces about 3,200 m^3/d.

411 The volume of waste going to Suncor's landfill will probably increase as the plant expands.

412 The Hangingstone disposal well is not a deep well. Due to the lack of deeper formations, the well is in the Lower McMurray formation at a depth of approximately 350 metres.

413 Landfill leachate will be recovered and used as recycled water.

414 The figures provided are for Phase I. The data for Phase II are not yet available.

415 The figures for Petro-Canada's MacKay River facility reflect both the current operation and a proposed expansion that has not yet been approved. The waste disposal estimates in the EIA assumed a "worst-case" scenario, by including both deep-well injection and a landfill (for waste from an evaporator/crystallizer), but the most likely scenario will be using an evaporator/crytstallizer unit, with the deep-well disposal for emergency use only.

416 Petro-Canada's Meadow Creek Project is currently on hold.

417 The reduction of deepwell disposal to zero in 2017 is based on the assumption that waste water will be returned to the depleted steam chambers to replace voidage.

418 Imperial's water treatment process is improving and newly developed technology is reducing the lime sludge produced by about one-third compared with earlier stages of the project.

419 EnCana's figure for Foster Creek is based on the anticipated average for 2005–2025, assuming 15,900 m^3/day or more of bitumen production.

Wolf Lake/Primrose	CNRL	CSS	1,191,000	0
Peace River Region				
Peace River[420]	Shell	CSS	1,434,000	0

Data source: Individual companies[421]

3.4 Impacts of conventional enhanced recovery

3.4.1 The current situation

The demand for fresh water for enhanced oil recovery varies across the province, both according to the density and age of wells, and the location within the province. In 2004, saline water accounted for 24% of water used for conventional oil recovery, 14% came from fresh groundwater and 62% came from surface water (based on water use data used in Figure 2-17). However, there are strong regional differences. Water basin data for 2001 shows that only saline water was used for EOR in the Milk River Basin. Saline water accounted for approximately half the water used in the South Saskatchewan Basin and in the Peace River Basin, but for only 26% of that used in the North Saskatchewan Basin and 4% of that used in the Athabasca River Basin.[422] The total volume of saline water used for conventional enhanced recovery was highest in the South Saskatchewan River Basin, followed by the Peace River Basin.

When oil is pumped to the surface, much of the injected water is produced, along with water naturally present with the oil. This produced water can be recycled. Since the mid-1980s, the average recycle rate for conventional oil recovery has exceeded 90%, and by 2001 it had reached 98%.[423] Since the recycling rate is already high, in most places the way to reduce the use of fresh and surface water will be to increase the use of saline water. There is an opportunity to increase the volume of saline water used in much of the province where deeper sedimentary rocks contain saline water.[424]

The impact of withdrawing water will vary, depending on whether the water is from surface water or groundwater. Withdrawals of shallow, fresh groundwater may impact surface waters if the water table is lowered, even temporarily. It is thus important for all river basin management plans to include groundwater as well as surface water. However, the integration of groundwater and surface water management systems is difficult because of different use patterns, different

[420] Figures are for current operations for 2004 only. Shell is planning an expansion at Peace River, but the water requirements for that project are not yet determined. Expected average water use from 2005 to 2025 is not available until water requirements for the expansion are determined.

[421] All companies listed in this table were invited to verify the data in a draft prepared by the Pembina Institute. We have done our best to ensure that the information is comparable and accurate at the time of publication. However, as company plans develop, the numbers may change. We thus recommend that any information be confirmed before it is cited in other publications.

[422] Geowa Information Technologies, Ltd. 2003. *Water Use for Injection Purposes in Alberta.* Prepared for Alberta Environment, http://www.waterforlife.gov.ab.ca/docs/geowa_report.pdf

The Appendix is online at http://www.waterforlife.gov.ab.ca/docs/geowa_appendix.pdf The 53 tables and figures in the appendix show the source water diverted for conventional oil recovery (for each of the main river basins in the province), for thermal projects, for the Green and White Zones, as well as the water balance and total volume disposed of each year, 1972–2001.

[423] Geowa Information Technologies, Ltd. 2003. *Water Use for Injection Purposes in Alberta, Appendix, Table 53*. Prepared for Alberta Environment, http://www.waterforlife.gov.ab.ca/docs/geowa_report.pdf

[424] Near the Canadian Shield there may not be any adjacent large-volume saline aquifers to draw on.

seasonal and annual storage characteristics, and very different replenishment and depletion characteristics during drought and flood conditions.[425]

Withdrawals of deep saline water will not usually affect surface waters or shallow groundwater. Some Albertans have objected to Alberta Environment issuing licences for fresh water for EOR as they want to ensure that there is sufficient fresh water for other purposes; water used for EOR stays underground and does not flow back into the river basin (that is, it is no longer part of the active water cycle). A case that drew much public attention concerned a licence issued to Capstone Energy to withdraw water from the Red Deer River. This case was brought to the Environmental Appeal Board by the City of Red Deer and the Mountain View Regional Water Services Commission, among others. Chamaelo Energy, which took over Capstone Energy, has since decided not to proceed with the project.[426] However, concerns about the impact of water withdrawals for EOR are not new, as seen by a study conducted in the Drayton Valley area three decades ago, outlined below.

3.4.2 The Drayton Valley area

The use of water for enhanced recovery started in the 1950s. In the Pembina oilfield, in west-central Alberta, secondary recovery using water started in 1956, three years after the discovery of this large field. It was found that whereas primary oil recovery could obtain 5–20% of the oil, enhanced recovery would extract an additional 10–20% across the pool. Large volumes of water were withdrawn from shallow aquifers to inject into the oil zone, with volumes reaching a peak in 1971. The volumes used varied across the oilfield, but the study found that, at that time, over-pumping had occurred and the hydraulic head declined in at least one location.[427]

Bedrock channels are one of the most important sources of groundwater in Alberta because an accumulation of sands and gravels is often found at their base. Within the Pembina field the Onoway and Drayton Valley bedrock channels are important aquifers. They are located along the Pembina and North Saskatchewan Rivers, so when water was pumped from the wells, the aquifers were recharged by direct infiltration from these rivers. However, in other areas the recharge was much slower. Records from two observation wells showed that, between 1961 and 1974, the long-term groundwater level dropped 2.4 metres at the Drayton Valley observation well (near a major concentration of water source wells), while at the Buck Creek well (where there were fewer water source wells) the long-term water level was constant. In the Drayton Valley area the aquifer being used for oilfield injection exceeded the short-term rate of recharge, since the aquifer was covered by over two metres of clay and shale, which slowed the downward

[425] Groundwater is also more difficult to manage than is surface water because it is expensive to drill the wells needed to understand and monitor groundwater flow over decades, relative to the relatively inexpensive and rapid gathering and analysis of surface water information.

[426] Environmental Appeal Board. 2004. *Mountain View Regional Water Services Commission et al. v. Director, Central Region, Regional Services, Alberta Environment re: Capstone Energy (26 April 2004), Appeal Nos. 03-116 and 03-118-121-R (A.E.A.B.),* http://www3.gov.ab.ca/eab The City of Red Deer and others challenged a licence to use water from the Red Deer River for EOR before the Environmental Appeal Board. Although the board recommended that Capstone Energy receive a licence for a reduced volume of water, they later decided not to withdraw water for enhanced recovery and the licence has expired. The company that later bought Capstone, Chamaelo Energy, indicated that they do not intend to proceed with the project. Hanneke Brooymans. 2005. Oil company drops plan to use Red Deer water: Had approval to pump river water down oil wells. *Edmonton Journal*, July 28, 2005. The EAB has dealt with other appeals to the use of water for oilfield injection, as seen from the board's annual reports. See, for example, the appeal with respect to Alberta Environment's decision to issue a licence from a non-saline well near Grande Prairie, another area where there is public concern about shallow aquifers. EAB 02-152, 03-001–03-003, 03-005 and 03-006 in *Annual Report 2003–2004*. In this case, Midnight Oil and Gas Ltd. (previously Slave River Exploration Ltd.) has announced that they are prepared to relinquish their water licence. See EAB, Status of Active Appeals, http://www3.gov.ab.ca/eab/status.htm

[427] Crowe, A. 1976. *Groundwater Resources of the Pembina Oilfield Area.* Prepared for Alberta Environment.

movement of precipitation. Although this data is historic, it is recounted here as the conclusion remains valid. The study pointed out that it is not possible to rely on general assumptions:

> It is recommended that where future large scale secondary recovery projects are foreseen, a complete groundwater study be undertaken on a local and regional basis. This may indicate where conflicts would develop between oil companies and the public on water usage, and there, aid in avoiding problems before they arise.[428]

This is still sound advice today (see section 6.3.2.1).

3.4.3 Future trends

Approximately one quarter of the initial conventional oil in place in Alberta is recovered; the rest remains in the ground.[429] Conventional oil production has been declining and will likely continue to decline as the pace of production is currently greater than the rate of discovery of new pools. The initial established reserves of crude oil were 2.7 million m^3 and cumulative production to 2004 was 2.4 million m^3, leaving only 9% of the initial established reserves in the ground, or enough to last seven years at the 2004 rate of production.[430] This suggests that the volume of water required for conventional oil recovery might decline. However, "recoverable" oil reserves change with time, due to new exploration, changes in technology and changing rules regarding "proven" oil reserve estimates. The EUB puts the ultimate potential recoverable crude oil at 3.1 million m^3. This additional oil can be recovered if new technology is put in place or existing methods become economic in areas where they are currently considered too expensive. Respondents to a survey conducted by the Petroleum Technology Alliance of Canada (PTAC) estimated that the recovery factor for conventional oil could be improved from the current 27% to 41%.[431] The PTAC report says that it is an open question whether these results are possible, but points to various improvements that have already been achieved with the introduction of new technologies (e.g., horizontal wells, new enhanced recovery techniques using carbon dioxide (CO_2), etc.) The development of very precise techniques for imaging details of conditions in a reservoir also enables engineers to devise improved methods of recovering the oil. The Alberta Research Council believes there are two major areas for improvement: increasing the recovery from conventional EOR waterflood schemes, and extending waterflood to fields previously considered economically unattractive.[432] As the price of oil rises, it is likely that more enhanced recovery projects will become viable. In light oil reservoirs the Alberta Research Council is investigating alternate water sources (e.g., water from CBM wells and the reuse of produced and waste water) as well as chemical applications and the use of gases to improve the efficiency of old waterflood operations. If these developments take place, there might be a change in the

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[428] Crowe, A. 1976. *Groundwater Resources of the Pembina Oilfield Area.* Prepared for Alberta Environment, p. 63.

[429] Petroleum Technology Alliance Canada. 2004. *Spudding Innovation Accelerating Technology Deployment in Natural Gas and Conventional Oil*, p. 21, http://www.ptac.org/techinnp. html

[430] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook.Statistical Servies ST98-2005,* p. 2.

[431] Petroleum Technology Alliance Canada. 2004**.** *Spudding Innovation Accelerating Technology Deployment in Natural Gas and Conventional Oil*, p. 37, http://www.ptac.org/techinnp. html

[432] Petroleum Technology Alliance Canada. 2005. *ARC's Technology Development Initiatives in Improved Waterflooding.* Information Session, Calgary, Alberta, October 18, 2005.

current declining trend in demand for water for conventional EOR, although in many areas of the province, the water used will frequently be saline water.[433]

3.5 Impacts of drilling and operating wells

The previous sections have focused on the use of water for oil recovery, but the exploration for oil and the drilling and operation of conventional and in situ wells may also impact water resources.

To locate oil, seismic surveys are conducted. A seismic survey involves sending out vibrations through rocks, using either dynamite charges placed in "shot holes" or large vibroseis trucks that vibrate heavy plates. There are potential impacts from drilling holes for explosives. After the dynamite is put in the hole (which may be 15–18 metres deep), the hole must be plugged approximately one metre below the surface and then covered with 40 centimetres of an approved impermeable substance such as bentonite. If water tables are shallow, seismic shot holes can provide communication between surface pollutants and potable water. The Alberta Surface Rights Federation is concerned that the government's requirements for plugging seismic holes are inadequate and fears that pollutants, such as herbicides, pesticides, fertilizers, or *E. coli* bacteria from cattle, may enter the groundwater through improperly plugged holes. They have repeatedly asked the government to ensure that the holes are filled from bottom to top with bentonite, or similar impervious material, as is required for water wells in Alberta and for seismic shot holes in Wyoming.[434] An Alberta government publication recommends that landowners negotiate with the seismic company to put the plastic plug closer to the bottom of each hole and fill from the plug to the ground surface with bentonite pellets.[435] This would prevent the flow of surface water through the hole and into an underground aquifer, or the movement of water from one formation to another. At the time of writing, a seismic/groundwater project is underway to assess whether current legislated shot hole abandonment methods are adequate to prevent overland flow (surface water) from reaching an aquifer via a permanently abandoned seismic shot hole.[436]

There is also a risk that seismic surveys may affect water wells.[437] Many landowners ask the company to pay for the testing of their water well when they negotiate a permit agreement for seismic activity on their land. This provides a baseline against which to compare any future

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[433] Alberta Environment. 2006. *Water Conservation and Allocation Policy for Oilfield Injection* and the associated guideline require a company to look for alternatives before applying for a licence to withdraw fresh water.

[434] Wyoming Oil and Gas Conservation Commission. Undated. *Rules. Chapter 4. Section 6. Geophysical/Seismic Operations* http://wogcc.state.wy.us/db/rules/4-6.html Unless the company can prove that an alternative method will provide better protection to groundwater and long-term land stability, operators are required to fill the shot hole with bentonite from the top of the explosive charge to a depth above the final water level (except where the final water level will be within three feet of the surface). A non-metallic plug must be set three feet below the surface and the hole above the plug must be filled with drill cuttings and tamped.

[435] Alberta Agriculture, Food and Rural Development, Alberta Environment, Agriculture and Agri-Food Canada. 2000. *Water Wells that Last for Generations,* p. 68.

[436] The pilot project, located near Gull Lake, involves Alberta Environment, Alberta Sustainable Resource Development, the Canadian Association of Petroleum Producers, Canadian Association of Geophysical Contractors, Small Explorers and Producers Association of Canada and the Alberta Water Well Drillers' Association. A bromide tracer was introduced in 2003 and monitoring is being conducted on an annual basis at piezometers about three metres from the shot holes

[437] It is rather unlikely that seismic sources will affect the mechanical condition in a well, but many of the reported issues with water wells could be due to surface leakage through shot holes into aquifers. Edo Nyland, Professor Emeritus, Physics, University of Alberta, personal communication, February 2006.

changes in well water quality. Landowners may also negotiate the testing of a water well before signing a lease agreement for a well to be drilled on their land.

To obtain water for drilling mud needed when drilling an oil well, companies may drill shallow water wells or they may obtain water from a dugout. Although in this case the total amount of water allocated for drilling is small relative to other uses of water, it may be a concern in water-short locations or if the water is taken from a small wetland area by a series of operators. The number of licences for temporary diversions reflects activity in the oil patch.[438] The number of temporary diversion licences for drilling oil and gas wells has increased dramatically in recent years, as more oil and gas wells are drilled in an effort to maintain supplies from a declining resource (see Table 3-3).

Table 3-3 Temporary water licences for drilling oil and gas wells in Alberta, 2002–2004

Temporary Diversion Licences	2002	2003	2004
Number of active licences	1,524	3,239	4,496
Number issued during the year	1,210	2,700	3,633

Data source: Alberta Environment

Some landowners have expressed concern that the use of water from dugouts for drilling may contaminate fresh aquifers, and want to ensure that only treated water is used for well drilling to protect surface aquifers.

After a conventional well is drilled, the well may be fractured by pumping in a liquid or gas under pressure to open up the rock so that the oil (or gas) can be drained more easily. Water is the base fluid for most fracturing, although various substances may be added, including a material that props the fracture open. There are no readily available statistics on the volume of water used for fracturing, since treated water is usually purchased from a municipality for this use.

There is a potential risk to groundwater from leaks in a well casing, or from leaks along the outside of the casing if the cement grout outside the casing does not form a tight enough seal with the surrounding rocks. The EUB requires companies to test new oil (and gas) wells for surface casing vent flows/gas migration and repair or monitor those with any leaks. A well must also be tested before it is abandoned.[439] These requirements are important because, if oil and gas wells are not properly cased or abandoned, it is possible for gas, oil or saline water from deeper formations to leak from the well bore and contaminate shallow potable water aquifers. Gas migration—the leakage of gas outside an oil or gas well—can occur if well bore casings are not properly cemented. If the gas escapes into an aquifer, it can cause bubbles in well water. If the gas escapes through the soil, it can impair the growth of vegetation and reduce crops.[440]

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[438] Information supplied by Alberta Environment. Water for drilling does not require a licence from Alberta Environment in the Green Zone (the forested area of the province), but companies are required to obtain approval from Alberta Sustainable Resource Development, which manages the forests. The number of licences for drilling reflects activity in the oilpatch. Alberta Environment, personal communication, January 2005.

[439] Alberta Energy and Utilities Board. 2003. *Interim Directive ID 2003-01: 1) Isolation Packer Testing, Reporting and Repair Requirements; 2) Surface Casing Vent Flow/Gas Migration Testing, Reporting, and Repair Requirements; 3) Casing Failure Reporting and Repair Requirements*, http://www.eub.gov.ab.ca/BBS/requirements/ils/ids/id2003-01.htm

[440] Schmitz, R., D. Van Stempvoort and B. Emo. 1994. *Gas Migration Research: Work Toward Risk-based Management*. Findings from this report were presented at the Alberta Surface Rights Federation AGM on March 20, 1995. The report states that, “While it is probable that gas migration occurs in other regions, the phenomenon is particularly visible in the Lloydminster area of Alberta and Saskatchewan. This is partly

Old oil and gas wells drilled before 1990 could potentially serve as a route for the mixing of waters of different quality. Historical cementing practices in many parts of Alberta have left zones containing usable water open to zones containing non-usable water.[441] In 1990 new requirements were introduced stipulating that, if the surface casing did not extend to below the depth of usable (fresh) water, the next string of casing must be cemented to the surface.[442] There were practical difficulties in applying the same requirement to existing wells, so at that time the department responsible for the environment (Alberta Environmental Protection) "accepted that usable waters of differing qualities may be left open to one another in Alberta's older wells."[443] Today, fresh groundwater zones must be cemented when a well is abandoned, so the number of wells in this category will be declining.

In 2004, the EUB inspected 2.8% of the nearly 18,600 wells (i.e., oil and gas wells) drilled during the year. Board staff specifically target higher risk situations for inspection. Of those inspected, 15% were unsatisfactory in some way, but the EUB reports that most of the unsatisfactory issues were minor in nature.[444] Thus, the fact that a well is unsatisfactory does not mean that it would necessarily impact the water.

The EUB reports on leaks and spills associated with handling water from oil and gas wells (combined). As a well ages, it produces some water with the gas or oil. This highly saline produced water must be re-injected into some deep formation after it is separated from the oil. All of the saline produced water must be transported from the production well, by truck or pipeline, to an injection or disposal well. In some cases this water is re-injected for enhanced recovery. The EUB figures do not distinguish the source of the water, but indicate that in 2004 15,300 m^3 of water were spilled in Alberta.[445] Most, if not all, of this water would be saline produced water. While the volume of spills and leaks appears small when compared to the total volume of saline water produced, transported and disposed in the entire province (600 million m^3 in 2002), the impacts of saline water leaks are a concern for landowners whose land is affected. The EUB has extensive regulations related to pipeline design, standards, construction, and monitoring to reduce risk of spills, as well as regulations that aim to prevent spills at well sites and facilities. Sometimes the spills will be at the wellhead, but in other cases they may result from a pipeline leak. In 2004 there were 183 incidents (mostly leaks) relating to pipelines transporting water related to oil and gas activities.[446] This is equivalent to one incident for every 112 kilometres of pipeline (since the total length of pipeline carrying water in 2004 was 20,578 km).[447] The EUB does not detail specific environmental impacts caused by any leak of saline

due to the high well density and the fact that much of the land is under cultivation, which makes the effects on vegetation more evident." The report estimated that over 4,000 wells in the area were affected.

[441] Austin, Brenda A., Sheila L. Baron and Stephen K. Skartstol. 1995. *Groundwater Protection in Wellbores.* Alberta Energy and Utilities Board, p. 1. Paper presented to the Canadian Association of Drilling Engineers/Canadian Association of Oilwell Drilling Contractors, Spring Drilling Conference, April 19–21, 1995.

[442] *Oil and Gas Conservation Regulation, section 6.080.*

[443] Austin, Brenda A., Sheila L. Baron and Stephen K. Skartstol. 1995. *Groundwater Protection in Wellbores.* Alberta Energy and Utilities Board, p. 7. Paper presented to the Canadian Association of Drilling Engineers/Canadian Association of Oilwell Drilling Contractors, Spring Drilling Conference, April 19–21, 1995.

[444] Alberta Energy and Utilities Board. 2004. *Field Surveillance Provincial Summary January–December 2004. ST57-2005,* p. 17.

[445] Alberta Energy and Utilities Board. 2004. *Field Surveillance Provincial Summary January–December 2004. ST57-2005,* p. 52.

[446] Alberta Energy and Utilities Board. 2004. *Field Surveillance Provincial Summary January–December 2004. ST57-2005,* p. 43.

[447] Alberta Energy and Utilities Board. 2004. *Field Surveillance Provincial Summary January–December 2004. ST57-2005,* p. 38.

water or distinguish between those related to conventional oil or gas recovery, enhanced recovery or in situ recovery of bitumen.

4. Technologies to reduce water use by the oil industry

Chapter 2 showed that the demand for water for oil sands production, both in situ and mining, is expected to increase substantially. Companies realize that water supplies are finite and that efforts are being made to reduce the volume of water used per unit of bitumen produced. However, due to the planned increase in the production of from the oil sands, and the fact that industry is not currently adopting technologies that avoid or substantially reduce water use in its commercial projects, the overall demand for water is expected to increase. The conservation and long-term sustainable management of freshwater resources must become prime objectives of the Alberta government, since this water may be required for ecosystem needs or other productive uses. This can be done by requiring industry to utilize saline water instead of fresh water, and to develop alternative technologies, as well as by providing existing allocation holders with meaningful incentives to develop technologies that optimize the recycling of produced water (see section 4.1). Sections 4.2 and 4.3 deal with oil sands mining and in situ recovery, respectively, while section 4.4 examines the use of alternatives to water for conventional oil recovery.

4.1 Use of saline water and water recycling

As was shown in Chapters 2 and 3, there is are considerable differences between companies in the types of water and technologies they use. This section examines the extent to which new technologies can increase the use of saline water and water recycling.

Companies are now expected to use saline water for EOR where this is practical and the water is accessible. If the water is to be used to generate steam, it will first need to be treated. Treatment is also required before produced water can be reused for steam generation.

Although conventional EOR and in situ bitumen projects often recycle the water they use, this is not universal. While the EUB usually requires water recycling for larger oil sands projects, including SAGD operations,[448] it has not been a regulatory requirement for conventional EOR. Companies have a strong business reason to practice recycling in conventional EOR and have achieved very high average levels of recycle. In the future, applications for water diversion for EOR will be reviewed, and companies are expected to show how they will maximize water recycling.[449] Possible changes in select pool operations and continuous oversight and reporting will help ensure continuation and improvement in recycling for conventional EOR. Also, if there is a pricing policy for water and the price is set at a high enough level, some companies may find it worthwhile to treat this water so that it can be reused by another oil and gas company or other industries, rather than sending it for deep well disposal.

[448] Alberta Energy and Utilities Board. 1989. *Informational Letter IL89-5: Water Recycling Guidelines and Water Use Information Reporting for In Situ Oil Sands Facilities in Alberta*, http://www.eub.gov.ab.ca/bbs/default.htm

[449] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection*, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

In 2003 half of all produced water in the province (0.8 million m^3/day or 300 million m^3/year) was injected for reservoir pressure maintenance and water flood secondary recovery projects; the other half was injected into disposal wells.[450] There is potential for much of this water to be treated and reused, and in future, before they apply for a licence to use fresh water, companies will have to examine whether there is an adjacent reasonable supply of produced water they could use. Various technologies have been developed to desalinize produced water, including distillation and membrane processes.[451, 452] The unit cost of desalinization depends on the salinity, the volume treated and the process used, but it may be approximately $3 per cubic metre.[453]

One new method uses an evaporation system to recycle produced water. It boasts a high water recycle rate and, since it does not use lime to remove the silica in the produced water, uses less chemicals in treatment. The residual wastes can be concentrated as dry solids for disposal in a class II landfill. At first glance, this system appears to be relatively expensive and it is not yet widely adopted. However, companies that have compared the full life-cycle capital and operating costs of various systems find the evaporation system to be competitive. If there were a volume charge for waste disposal to landfill, the evaporation system would become even more attractive. Suncor selected an evaporation system for Stage 2 of its Firebag operation. In this case, the concentrated brine waste from the process is treated to remove dissolved minerals and the solid waste (mainly silica) is sent for landfill, while the residual liquid is sent to a disposal well. Evaporator systems have also been installed at the JACOS Hangingstone facility and at Petro-Canada's MacKay River to treat recycled water before it is used to generate steam. Phase II of Deer Creek's Joslyn facility is the first SAGD project to use a fully integrated system that incorporates both an evaporator and a zero liquid discharge crystallizer system.[454] This enables all the liquids to be recycled, while the remaining solid waste is sent to landfill.

Several companies are working on processes to improve water recycling, but it is too early to know for certain which ones will be most suitable for treating water for bitumen recovery.

Reverse osmosis, which separates and concentrates dissolved contaminants using membranes, is a frequently used water treatment process. It does not require energy to operate, but does require a pressurized water source. At the present time it is not well suited for produced water, which may contain traces of oil. Even very small quantities of oil can plug the membranes. Also, the process works best with cold water; the cartridges housing the membranes are damaged by heat

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[450] Hum, Florence, Peter Tsang, Thomas Harding and Apostoles Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy, University of Calgary, p. 3. The data was drawn from ACCUMAP, a commercial database for oil and gas.

[451] Hum, Florence, Peter Tsang, Thomas Harding and Apostoles Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy, University of Calgary, p. 17.

[452] Husky. Energy. 2003. *Tucker Lake Thermal Project. Supplemental Information. Question #68. Water Management,* p. 152. The response indicates that the company will use weak acid cation softeners, if using water with a TDS below 30,000 ppm and that the process is already in use in several thermal plants in Alberta.

[453] Hum, Florence, Peter Tsang, Thomas Harding and Apostoles Kantzas. 2005. *Review of Produced Water Recycle and Beneficial Reuse.* Institute for Sustainable Energy, Environment and Economy, University of Calgary, p. 27. As stated in the report (p. 34), "The estimated cost of treating produced water to meet drinking water qualities is up to $0.43/barrel, compared to $0.19/barrel at a City of Edmonton loading point and $0.14/barrel supplied by the City of Calgary to surrounding municipal districts."

[454] Heins, William. 2005. *Worlds First SAGD Facility Using Evaporators, Drum Boilers, and Zero Discharge Crystallizers to Treat Produced Water.* GE Ionics Presentation at Petroleum Technology Alliance Canada's 2005 Water Efficiency and Innovation Forum. The facility is the Deer Creek Joslyn Phase II. See also, William Heins and Dan Peterson. 2005.Use of evaporation for heavy oil produced water treatment. *Journal of Canadian Petroleum Technology,* Jan. 2005, Vol. 44, No. 1, p. 26–30, http://www.deercreekenergy.com/presentations/tech_pres.html

in the produced water. Thus new materials will be needed that are not affected by heat before this process is widely adopted for treating produced water in thermal recovery operations like SAGD.

All water treatment processes produce some residual waste, although the volume is relatively small in a zero liquid discharge system. More work is needed to determine the relative risks of landfill versus the deep well disposal of wastes, and to suggest which treatment minimizes environmental risks. In future, various lower quality water sources such as municipal wastewater, treated sewage, or discharges from industrial or power plant cooling systems might be used for oil recovery or other energy-related processes.[455,456] If these sources are used, the water will not flow back into the river basin, so the impact of the diversion on rivers and streams should be considered, in the same manner as when fresh water is withdrawn. When looking at alternative water sources the potential impact of pipeline leaks must also be considered. It is essential to ensure that the water is treated and that there is no risk of contamination of fresh aquifers.

4.2 Technologies to reduce water use and impacts for oil sands mining

When addressing the impacts of water use for oil sands mining, it is important to not solely focus on the impacts of net water use but to consider the impacts of total water use. This is particularly important since

- operators require significant “start-up” volumes of fresh water withdrawn from the Athabasca River, due to the “total” water intensity of mining/upgrading operations;
- reductions in the net water withdrawal from the Athabasca River through enhanced recycle do not address the fact that the current water-based extraction process leads to the production of significant volumes of tailings (both CT and MFT), posing significant and uncertain reclamation challenges that have yet to be overcome;
- enhanced water recycle, while positive, is an “end-of-pipe” solution that fails to address the fundamental problem: reliance on water-based extraction processes; and
- the current need to store large volumes of water onsite in tailings ponds presents an ongoing risk to water quality as a result of seepage from tailings ponds into groundwater and the risk of a tailings dyke breach and the release of tailings material into the watershed.

Unfortunately, while the above clearly suggest that a step-wise change to a non-water-based extraction technology would best address the issues, it has been suggested that no major breakthroughs or alternatives to water-based bitumen extraction are expected, and alternative processes appear unlikely to provide significant advances over the current approach before

[455] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 13.

[456] For example, Petro-Canada has constructed a pipeline to take recycled water from the municipal waste treatment facility in Edmonton to its refinery. Petro-Canada. 2005. *Petro-Canada Refinery Conversion Project News,* Vol. 5, No. 12, Fall 2005.

2030.[457] That said, research and piloting processes are underway to evaluate technology options that may reduce water requirements. These technologies include

1. Dry tailings technologies

The "Bitmin" extraction technology, which will be piloted on a commercial scale by UTS Energy Corporation and Petro-Canada at the Fort Hills site, is a dry tailings technology.[458] If successful, this technology would represent a significant improvement in the use of water, and would limit the need for water. Similarly, some methods of combined upgrading and extraction (e.g., Taciuk processor) are able to produce dry tailings, and would therefore result in a smaller and more stable tailings stream with a much lower water content.[459] In addition to addressing issues associated with water, this would allow for more rapid progressive reclamation.

2. Further develop tailings consolidation technologies

The current practice for consolidating fluid MFT is to add a coagulant (gypsum) and co-dispose with dense coarse tailings (sand). This approach is variously known as non-segregating tailings, CT and composite tailings. These techniques may address the large inventory of fluid fine tailings but require that sufficient coarse tailings are available and that the final landscape can accept large volumes of potentially liquefiable sand.[460]

3. Promoting accelerated fine solids settling in the tailings ponds

By accelerating the settling of fine solids, water from the tailings pond can be more quickly recycled, thereby reducing the requirement for make-up water from the Athabasca River. Rapid dewatering of fine tailings using equipment such as thickeners would be a key for improved tailings practices, including drying of densified fine tailings in sub-aerial drying beds.[461]

4. Reduce requirements for process cooling

Upgraders seek to maximize the use of heat exchangers to minimize net additions of energy to the process, which reduces the volumes of water consumed for process cooling. As energy and emissions costs increase, operators will be presented with added incentive to improve energy efficiency, which will also tend to reduce demands for cooling water.[462]

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[457] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 26, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[458] UTS Energy Corporation. 2005. Fort Hills files regulatory application and advances BITMIN testing. *News Release*, April 12, 2005, http://www.oilpatchupdates.com/news-reader.asp?ID=22723 As stated in the release, "SNC-Lavalin Inc. has been awarded a contract for the engineering, procurement and construction of an experimental plant to demonstrate the BITMIN extraction process at a near commercial scale. The plant will produce approximately 3,500 barrels per day of bitumen froth from oil sands mined on the Fort Hills lease using the BITMIN process, which was extensively piloted in the 1990's. Fort Hills is considering utilizing the BITMIN process in its commercial operations. The estimated expenditure for the BITMIN demonstration is approximately $37.0 million and work will commence immediately with construction anticipated this summer subject to regulatory approval."

[459] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 45, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[460] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 37, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[461] Alberta Chamber of Resources. 2004. *Oil Sands Technology Roadmap: Unlocking the Potential. Final Report,* p. 38, http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

[462] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 45. http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

4.3 Technologies to reduce water use in in situ recovery

The oil sands industry is more concerned about the cost of energy to produce oil than about the use of water. It takes about 28 m^3 of gas to produce one cubic metre of bitumen in in situ operations and about 14 m^3 for integrated (mining and upgrading) oil sands projects.[463] New technologies are being developed in response to high energy costs linked to in situ bitumen recovery that could also reduce the use of water for in situ recovery. These include processes that use

1. **Solvents.** Research has been undertaken into the use of solvents to reduce the viscosity of the bitumen for in situ recovery. Various solvents have been used, either alone, in blends, as heated solvents or combined with steam.[464] In the VAPEX solvent process, vaporized solvents (such as propane, butane or CO_2) are injected into the bitumen reservoir with a carrier gas such as methane. The process uses a gravity drainage system and a pair of horizontal wells for injection and production, as with SAGD. A pilot project at Petro-Canada's Dover Underground Test Facility started using solvents in 2003 in a project that is expected to continue until 2008.[465] EnCana also has a pilot using VAPEX at its Foster Creek operations.[466] VAPEX is probably at the same stage in development that SAGD was five to ten years ago. Assuming the VAPEX process can be established, it might be possible to use CO_2 as the solvent.[467] When solvents are used alone, they not only completely replace water, but also save energy since the process works at atmospheric temperatures (10–20^{o}C).

2. **Solvents and heat.** Thermal solvent processes use heat (in the form of steam) as well as a solvent. Suncor has a pilot plant using this technology near their Firebag SAGD project.[468] Petro-Canada's Mackay River project also has a pilot using solvents with steam.[469] A new thermal solvent process employing petroleum coke or bitumen plus oxygen as heating fuel is being developed, which not only recycles hot solvent but stores greenhouse gases, such as CO_2, or pollutants, such as SO_2, in the reservoir.[470] This process uses not only less water but also less fuel than current steam-assisted methods.

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[463] National Energy Board. 2004. *Canada's Oil Sands: Opportunities and Challenges to 2015, An Energy Market Assessment, Questions and Answers,* p. 4.

[464] Alberta Energy Research Institute. 2005. *Alberta Energy Research Institute 2004–05 Annual Report,* p. 21, http://www.aeri.ab.ca/sec/new_res/pub_001_1.cfm

[465] Petroleum Technology Alliance Canada. 2002. PTAC VAPEX pre-pilots enable $30 million heavy oil pilot project—DOVAP technology to reduce emissions. *P-talk Newsletter*, November, Issue 22, http://www.ptac.org/about/ptalk0203.html#Reality

[466] Palgren, Claes. 2005. *The Technology Triangle Athabasca Bitumen VAPEX Pilot.* Petro-Canada presentation at Petroleum Technology Alliance Canada's 2005 Water Efficiency and Innovation Forum.

[467] Jaremko, Deborah. 2005. EOR economics: Conventional hydrocarbon floods waning as costs increase for miscible agents. *Oilweek Magazine*, April, p. 59.

[468] Suncor. 2000. *Firebag Enhanced Thermal Solvent Extraction Experimental Pilot Application for Approval to EUB.*

[469] Petro-Canada. 1998. *Application for Commercial Approval of MacKay River Project.*

[470] There is a report on the project at the federal government's Climate Change website at http://www.climatechange.gc.ca/english/team_2004/dbProjects/viewProject.asp?id=5377&typ=ind It is reported that a project undertaken by Suncor Energy and others found that the use of propane as the solvent and petroleum coke as the fuel provides the most cost-effective option for extracting bitumen and heavy oil. It purports to combine the best features and eliminate many disadvantages associated with the SAGD and VAPEX processes. The proponents claimed that the petroleum coke fuel/100% propane solvent combination also reduces CO_2 emissions by 80 to 85% compared to the steam-based recovery process using natural gas as a fuel.

3. **In situ combustion or gasification of the bitumen.** THAI is being used in a pilot project being developed by Whitesands Insitu Ltd.[471] The process uses some fresh water to generate steam for the preliminary heating phase, but then requires no more water. Field tests will reveal the actual bitumen recovery rates, but it is hoped that, if successful, the process could recover 70–80% of the oil in place, much higher than the recovery possible with SAGD. THAI might be improved with the use of catalysts, such as that being developed in the Controlled Atmospheric Pressure Resin Infusion (CAPRI™) process.

4. **Electrical heaters to warm bitumen.** In 2004 Shell completed drilling 30 wells from two well pads at its Peace River in situ operation to test the use of electrical heaters to gradually heat the reservoir and convert the heavy oil to lighter crude oil underground.[472]As Shell explains,

> The heavier hydrocarbons remain underground while the lighter higher quality crude oil and gas are moved to the surface. This small-scale research project will provide information on whether this is a better method of producing oil from an economic, social and environmental perspective.

5. **Electro-magnetic stimulation.** Microwave-frequency heating might be used to warm reservoirs and potentially eliminate the use of water, especially in less viscous heavy oil reserves. This technology would require basic research, and only if that research is successful could the ideas be developed for a pilot project.[473]

Further work is needed to find ways to reduce the volume of water used, or the impacts of in situ recovery on groundwater, that are independent of research into technology designed to lower the cost of energy input. Important research topics for in situ recovery have been identified in a recent study:[474]

1. Identify and test technologies that enable 100% recycling of produced water. According to the study,

> Uncertainties about future water supplies and the capacity of underground formations to supply large volumes of brackish water, or to accept blow-down, require that low cost (capital and operating) methods be developed to purge minerals from the active water/steam energy transfer system.[475]

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[471] Petrobank Energy and Resources Ltd. 2005. *THAI Technology*, http://www.petrobank.com/ops/html/cnt_white_project.html See also *Whitesands Experimental Project* in June newsletter at that site, and *Petrobank Initiates $30 Million Whitesands Pilot Project Financing.* News release, January 15, http://www.petrobank.com/invest/html/news_2004/news_01_15_04.html Initially, steam is injected through the air injection and production wells for two to three months, to heat the formation. Then air is injected and combustion starts.

[472] Shell Canada. 2005. Research project tests new technology. *Peace River Complex Newsletter.* Winter, http://www.shell.com/static/ca-en/downloads/news_and_library/news/peaceriver_newsletter_dec15.pdf

[473] Flint, Len. 2005. *Bitumen Recovery Technology: A Review of Long Term R & D Opportunities.* Lenef Consulting (1994) Ltd. Study funded by Natural Resources Canada, http://www.ptac.org/about/ptalk0501.html#Oil

[474] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 18–22, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

[475] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* p. 19, http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

2. Assess the capacity of shallow saline aquifers to supply water. Does demand exceed the sustainable supply? At what rate will the aquifers be recharged?
3. Determine the potential impact of incomplete voidage replacement on surface water and shallow aquifers (see above, section 3.3.1). At what rate will water flow downwards to fill the voids left by the removal of the bitumen in the SAGD process? Will this have any effect on freshwater aquifers?
4. Assess the impact of disposing large volumes of water into deep aquifers. Is there any risk that wastewater will migrate to shallower zones?
5. Determine long-term water balances for basins and sub-basins across the region (i.e., the relationship between draw down and recharge) to ensure security of water supply, not only for other users but also for downstream ecosystems. It is crucial that this work include a review of surface flows, underground aquifers and the potential impacts of climate change.

In addition, companies should pay attention to reducing waste from water treatment processes. Several new processes are being developed, but are not yet regarded by the industry as proven technology. It is important to evaluate which poses the lesser long-term environmental risk: deepwell disposal of wastes from the water treatment process, or further treatment that concentrates the wastes into a form that can be landfilled. The latter has the advantage that it enables the highest possible volume of water to be recycled. However, it means that long-term monitoring of the landfill and collection of leachate will be required, to ensure that there is no risk of contamination of shallow aquifers. Both deep well disposal and landfilling have environmental risks and benefits that need to be balanced on a case-by-case basis; there is no one-answer-fits-all for waste treatment. The *Water Conservation and Allocation Guideline for Oilfield Injection* outlines a process for evaluating environmental net effects for each project.[476]

4.4 Technologies to reduce water use in conventional oil recovery

Even though the volume of water used for drilling is small as compared to the volume required for EOR, technology has made it possible and economic to recycle water for these temporary uses. Small, mobile units have been developed that can move from site to site to treat wastewater or recycle water used for fracturing.[477] Recycling can be economic, despite the fact that the charge for fresh water is still relatively low, since it saves the costs of trucking and waste water disposal.[478]

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[476] Alberta Environment. 2006. *Water Conservation and Allocation Guideline for Oilfield Injection,* Section 3.2.6, http://www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[477] Horner, Patrick. 2005. *Mobile Oilfield Wastewater Recycling.* AquaPure presentation at Petroleum Technology Alliance of Canada's 2005 Water Efficiency and Innovation Forum.

[478] Leshchyshyn, T. 2005. *Produced Formation Water and Recycled Fluids for Propped Fracturing.* BJ Services Company Canada presentation at Petroleum Technology Alliance of Canada's 2005 Water Efficiency and Innovation Forum. At the present time, there are considerable economic benefits from water recycling. However, as the cost of water is so low, the savings on water as a result of recycling represent less than 20% of savings for the entire project, with other savings resulting from reduced transportation and disposal costs, and so on. In an example relating to the fracing of 50 wells, the money saved through recycling was as follows: Disposal well charge: $12,500, disposal trucking $22,000, water trucking $17,000, water supply $1,900, water surcharge (additional municipal fees) $9,000 = $62,400.

Although the volume of new water required for conventional EOR has gradually declined, Alberta Environment and the EUB should ensure that recycling of produced water is maximized, and as little as possible is sent for deep well disposal (see section 4.1). Saline water can be substituted for fresh. Sometimes treatment will be required depending on the composition of the formation. In some cases, saline water may be preferable to fresh water, since it inhibits the development of sulphur microbes that can lead to the in situ development of hydrogen sulphide.

After water flooding, additional oil may be removed from a formation by tertiary recovery, using a process referred to as miscible flooding. Miscible flooding uses natural gas liquids (such as ethane, propane or butane) to reduce the viscosity of the oil or gases such as CO_2 and nitrogen. CO_2 is also already used in a few miscible floods. Since the removal of CO_2 from the atmosphere reduces greenhouse gas emissions, and since some of the CO_2 is believed to remain in the formation, this process is likely to receive increasing attention. Some water flooding will need to precede the use of CO_2 in a miscible flood operation or be injected as periodic slugs. Water provides a buffer between the CO_2 and the oil; it prevents the gas "breaking through" into the production well. However, using CO_2 can reduce the net water-to-gas ratio from 2.8 to 1.8.[479] In suitable formations it might be possible to further reduce the use of water by moving from water flooding to miscible flooding at an earlier stage in the enhanced recovery process.

PennWest Petroleum has been using miscible flooding at Joffre in central Alberta since 1982, drawing CO_2 from a nearby petrochemical plant.[480] A pilot project using CO_2 has been operating at EnCana's Weyburn facility in Saskatchewan since 2000 and several pilot projects are underway in Alberta. PennWest and Devon Canada are using CO_2 for EOR (in the Pembina Cardium oil pool and Swan Hills field, respectively) while Anadarko and Apache will use acid gas (a mixed of hydrogen sulphide and CO_2) from local gas plants for miscible flooding.[481]

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[479] Hawkins, Blaine and Ashok Singhal. 2004. *Enhanced Oil Recovery Water Usage.* Alberta Research Council. Presentation to the Advisory Committee on Water Use Practice and Policy, March 2, 2004, http://www.waterforlife.gov.ab.ca/html/technical_reports.html The water:oil ratio using a gas or solvent is 5:1, with a net water:oil ratio of 1.8; this compares with a water:oil ratio of 10:1 for water-based recovery, with a net ratio of 2.8.

[480] Peachy, Bruce. 2005. *Water and Energy Forum.* Petroleum Technology Alliance of Canada. Edmonton, Alberta. June 14, 2005. It was reported that 20% incremental oil recovery has been achieved using CO_2, up from 40% recovery using water at PennWest's Joffre project.

[481] Alberta Energy. 2004. Companies named for pilot CO_2 storage projects. *News Release,* April 30, 2004. Anadarko's project is at the Enchant Arcs oil pool in southern Alberta. The Apache project is at the Zama Keg River oil pool in northwestern Alberta.

5. Policies to reduce water use by the oil industry

5.1 Introduction

The management of water from both a quality and quantity perspective is an issue not only in Alberta, but around the world. In the last 50 years, the world population has roughly doubled, while water consumption has quadrupled. Industry, broadly defined, is the fastest growing user of freshwater resources worldwide, and demand from this sector is expected to more than double over the next two decades.[482] This increase in demand is despite improvements in water use efficiency by the industrial sector. Specifically, industry in Organization for Economic Co-operation and Development (OECD) countries has reduced total fresh water use by 12% in the past two decades and increased water recycling and reuse. This trend is in contrast to the overall trend for the oil sector in Alberta, where the use of water has been increasing for oil sands mining and in situ recovery of bitumen. As noted earlier, the use of saline water for oilfield injection has grown, but the use of fresh groundwater has also increased. The use of fresh groundwater for in situ recovery of bitumen more than offsets the decline in use of surface water for conventional EOR (see Table 2-4) and the use of fresh water for in situ recovery is growing much faster than predicted (see Figure 2-20).

Chapter 2 of this report describes the *Water Conservation and Allocation Policy for Oilfield Injection*. However, as will be described below, this framework fails to provide sufficient incentive to reduce water use for oil sands development, especially as the new policy does not apply to oil sands mining, which uses very large amounts of water. More specifically, under the current policy regime, the provincial government does not charge companies for the amount of water they use; for companies it is significantly more economical to invest in increased oil production than in reduced water consumption. This is a major barrier to reduced water use and requires action by the provincial government to overcome. The purpose of this chapter is to evaluate a range of policy options for reducing water use by the oil sector and improving the water management framework related to water use by the oil sector in Alberta. To do so, we answer the following questions:

1. What gaps exist in the government of Alberta’s current policy framework related to reducing water use by the oil sector?
2. What would a more appropriate policy framework look like?
3. What policy options are available to respond to those gaps?

In the sub-sections that follow, we describe the gaps in the current policy framework with respect to reducing water use by the oil sector, and identify and assess policy options for responding to those gaps.

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[482] Organization for Economic Co-operation and Development. 2003. Improving water management: Recent OECD experience. *OECD Observer*, March 2003, p. 1.

5.2 Existing policy gaps

In Alberta, like elsewhere, as demand for water increases and shortages occur, management of this resource becomes increasingly important. Effective management requires a comprehensive policy framework that takes into account that water resources are public and ensures that decisions on water use are based on high-quality data and scientific knowledge. A framework must also balance current and future water demands, prevent wasteful use of the resource, weigh the relative worth of different water uses and provide adequate protection for ecosystems. So too the framework must be adaptable, allowing for changing objectives and priorities over time.[483] The current policy framework in Alberta related to water use by the oil sector is inadequate. More specifically,

- there is not sufficient high quality data and information on which to base policy decisions;
- the policy framework does not ensure that the full costs of water use are borne by the oil sector and therefore it does not provide a financial incentive to reduce water consumption;
- the policy framework does not drive innovation or encourage and/or require the use of the best available technologies and processes when it comes to water conservation; and
- the policy framework is not adaptable and therefore cannot adequately adjust to changing climatic, geographic, and/or socio-economic conditions.

The issues identified above are considered in detail below. For each issue, we begin by describing what a more appropriate policy framework would look like. We then describe the current policy status and identify the government response that is required to address it. The goal of the suggested government response is to create a water management framework that achieves conservation objectives and addresses the issues identified above. In the subsequent section, we assess specific policy options for achieving the required response.

5.2.1 Information and Data Requirements

The Need: Policy decisions and measures need to be based on comprehensive, readily available and up-to-date scientific knowledge and high-quality data.

The Issue: Information and data on Alberta's groundwater resources and the use of water by the oil industry are incomplete. This is despite the fact that Alberta's *Water for Life* strategy identifies information and knowledge of the provincial water resources as the most critical element to managing water effectively.[484]

Alberta Environment has recognized that there is a lack of information on groundwater supplies in the province, making it difficult to know whether fresh groundwater use by the petroleum industry is sustainable.[485] A multistakeholder consultation hosted by the Canada West Foundation identified that lack of data and information on the total supply of groundwater and surface water, and the lack of data on actual water use by all sectors, hindered decision making

[483] Teerink, John R. and Masarhiro Nakashima. 1993. *Water Allocation, Rights, and Pricing. Examples from Japan and the United States.* World Bank Technical Paper Number 198. Washington, DC.

[484] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability*, p. 11, http://www.waterforlife.gov.ab.ca/

[485] Alberta Association of Municipal Districts and Counties. 2003. *Backgrounder on Water Issues.* Alberta: AAMD&C., p. 22.

in Alberta.[486] Likewise, the Advisory Committee on Water Use Practice and Policy pointed out that more research and knowledge is required with respect to water use by the oil sector. For example, the committee identified the need for additional information on the implications of limiting the use of fresh water in enhanced recovery operations and the need for increased research into water conservation and recycling for oilfield wastewater and salt cavern washing operations. After discussing the idea of reduction targets for fresh water used for underground injection, the committee determined that there was insufficient information on which to base specific targets. To obtain this information, the committee recommended the establishment of a public database reporting on relevant data.[487]

Without a clear picture of current water supplies, the amount of water being consumed, the means available for reducing water use and the alternatives (and associated implications) to water use that are available, it is difficult to introduce new water conservation policies. To respond to part of this information need, Alberta Environment and the Ministry of Energy have recently updated a database to more easily map and extract details of the volume of water used and the source of the water (surface, fresh groundwater and saline) in the province. Alberta Environment recognizes the need for better information on groundwater resources and has established a long-term goal to respond to these needs. However, information and data gaps remain today with respect to the total supply and flow of groundwater in the province, as well as interactions between surface hydrologic cycles and the groundwater flow system. Gaps also remain on the impact of limiting the use of fresh water in enhanced recovery operations. There is a need for increased water conservation and recycling research for industrial waste disposal and salt cavern washing operations (as identified by the Advisory Committee).

Proposed Policy Response: The government of Alberta needs to complete, as soon as possible, a comprehensive, high quality and publicly available inventory, which should be updated on a regular basis, of the supply and flow of groundwater in the province of Alberta. It should fill the information gaps identified by the Advisory Committee and strive to anticipate and fill any future information and data gaps.

This information must inform future allocations. In watersheds where the demand for water is high, relative to the short- and long-term sustainable supply, a water balance should be prepared to ensure that withdrawals do not exceed the sustainable aquifer yield.[488] Estimation of the long-term sustainable yield should consider the impacts of climate change, as well as other influences that could affect recharge rates.

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[486] Wilkie, Karen. 2005. *Balancing Act: Water Conservation and Economic Growth.* Canada West Foundation, p. 23, http://www.cwf.ca/

[487] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* p. 17, http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf

[488] For example, Ontario Regulation 387/04 *Water Taking and Transfer Regulation, section 4* states that the director who is responsible for water allocations must consider (insofar as there is information and to the extent that it is relevant) the impact of a proposed water taking on the natural variability of water flow, minimum stream flow and habitat that depends on water flow or levels, as well as the interrelationship between groundwater and surface water, if they may be affected by the water taking. In Alberta, before issuing a licence, the director must consider the relevant water basin management plan, where one exists. Two water basin management plans have been in effect for some years and others are being prepared. According to the *Water Act, section 9(2)e*, a water management plan must follow the framework for water management planning. Although the *Framework for Water Management Planning* (http://www3.gov.ab.ca/env/water/legislation/framework.pdf) includes groundwater it does not have any specific requirements or guidance with respect to the sustainable management of aquifers. Moreover, although when issuing a licence the director *may* consider any existing, potential or cumulative effects on the aquatic environment as well as hydrological and hydrogeological effects, and so on, this is not mandatory (Alberta *Water Act, section 51 (4)).*

5.2.2 Full Cost Accounting

The Need: An appropriate policy framework for water use incorporates the principle of full cost accounting.[489] There is a global trend towards full cost accounting as an integral part of a water management regime. Within the oil sector, full cost accounting is required to ensure that companies are responsible for the total costs of their water use and that society is not left to bear costs associated with reduced water quality or quantity.

The Issue: Current government policy in Alberta related to water use by the oil sector is not based on full cost accounting.

The provincial government collects a nominal administrative fee from the oil sector for water allocations. Fees do not account for the full cost of water use and are not tied to the actual amount of water used. Thus, there is no direct financial advantage to the oil sector to use less than their allocated amount. Once the water allocation has been obtained, access to the water resource is free.

In recognition of private company use of a public resource, and to encourage efficient use of water, the water pricing schemes for the oil sector should reflect the *full* cost of water use. This means accounting not only for administrative, monitoring and infrastructure costs (e.g., publicly constructed and maintained dams), but environmental and resource depletion costs as well. The price charged for water should reflect costs associated with water consumption and wastewater disposal.

The need to ensure that the price of water reflects full costs was identified in the Canada West Foundation multistakeholder consultation on water. Specifically, within the consultation “[t]here was strong agreement that determining the true value of water is central to demand management. The current value system treats water as essentially free.”[490] The consultation also noted that within the current policy framework “[e]fficient use of water is discouraged—the current allocation system has a ‘use it or lose it’ structure, a lack of pricing and a lack of incentives to conserve, all of which discourage the efficient use of water.”[491] According to research undertaken by the federal government, this is the case elsewhere in Canada as well: “[P]ublic policy in Canada has exhibited an almost total disregard for the potential uses of economic policies for water management. There is an absence of consideration of incentive mechanisms such as is created through water pricing, effluent discharge fees and the like.”[492]

The Advisory Committee on Water Use Practice and Policy recommended that the government should “evaluate economic instruments to support reductions in the use of fresh water for

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[489] While in principle full cost accounting principles should be applied not only to the oil sector, but to other sectors as well, given the scope of this paper, we focus our analysis on the application of full cost accounting to the oil sector only.

[490] Wilkie, Karen. 2005. *Balancing Act: Water Conservation and Economic Growth.* Canada West Foundation, p. 20, http://www.cwf.ca/

[491] Wilkie, Karen. 2005. *Balancing Act: Water Conservation and Economic Growth.* Canada West Foundation, p. 21, http://www.cwf.ca/

[492] Tate, M. Donald, Steven Renzetti and H.A. Shaw. 1992. *Economic Instruments for Water Management: The Case for Industrial Water Pricing*. Social Science Series No. 26. Ottawa, ON: Ecosystem and Sciences and Evaluation Directorate, Economics and Conservation Branch.

underground injection."[493] They asked the government to "consider what economic instruments might be useful to encourage industry participation (e.g., incentives, differential fees, etc.)."[494]

The *Water Act* provides the government of Alberta with the opportunity to use economic policies to spur water conservation. For example, the *Water Act* allows the transfer of water rights, if certain conditions are met.[495] Under the transfer system, the rights associated with a licence can be separated from the particular project to which they were originally linked and can be transferred to new or alternative uses in the same area.[496] This system of transferring rights is only relevant in areas of the province where there is an approved water management plan that allows transfers or where transfer is approved by Order in Council.[497] Without the ability to transfer rights, new or alternative water uses cannot be accommodated in areas where the maximum allocation has already occurred. The transfer is voluntary requiring a willing buyer and a willing seller and approval from the Alberta Environment Director responsible for implementing the *Water Act*. As well, the *Water for Life* strategy identified the following key actions to be carried out by the Alberta government related to economic policy and water conservation:[498]

- Determine and report on the true value of water in relation to the provincial economy.
- Complete an evaluation and make recommendations on the merit of economic instruments to meet water conservation and productivity objectives.
- Implement economic instruments as necessary to meet water conservation and productivity objectives.

These activities have not yet been completed and, as stated above, the water management framework related to water consumption by the oil sector in Alberta is currently not based on full cost accounting. Allowing water to be consumed without appropriate compensation is an implicit form of a subsidy and is contrary to global trends towards full cost accounting for water resources.

Proposed Policy Response: The government of Alberta should take a full cost accounting approach to water management for the oil sector in Alberta. That means ensuring that the price the oil sector pays for water resources reflects administrative, monitoring and any infrastructure costs as well as environmental and resource depletion costs.

5.2.3 Innovation and Best Available Technologies and Processes

The Need: A policy framework for water use by the oil sector needs to drive the oil industry to find innovative technologies and practices that eliminate or reduce water use.

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[493] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* p. 5, http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf

[494] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* p. 21, http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf

[495] An application to transfer water rights will only be considered if the transfer has been authorized in an applicable approved water management plan or by an order of the Lieutenant Governor in Council.

[496] Part 5, Division 2 of the Water Act contains the details related to water allocation transfers, http://www.qp.gov.ab.ca/documents/Acts/W03.cfm?frm_isbn=0779727428&type=htm

[497] *Water Act, section 81(7).*

[498] Government of Alberta. 2003. *Water for Life: Alberta's Strategy for Sustainability,* http://www.waterforlife.gov.ab.ca/

The Issue: The current policy framework in Alberta provides limited requirements for the oil sector to adopt best available technologies and practices to eliminate or reduce water use, and it does not encourage innovation.

While the government of Alberta has driven innovation in Alberta through use of joint industry, government demonstration and pilot projects that demonstrate the commercial applicability of certain technologies, there are only limited provisions within the current water management framework in Alberta that actually require the use of best available technologies and practices by the oil sector in the context of water use. Two such policy provisions are currently in place: First, companies requesting the use of fresh groundwater in the White Area of the province are required to demonstrate that no useful alternative to the use of fresh groundwater is feasibly available when they apply for a licence. This is an important provision that may explain the reduced consumption of fresh groundwater in the White Area, relative to the Green Area of the province. In 2001, the volume of fresh water used for oilfield injection in the Green Area was three times the volume of saline water.[499] Under the new *Water Conservation and Allocation Policy for Oilfield Injection*, the "White Area" policy will apply to all freshwater allocations in the province, from both surface water and groundwater. Every company will be required to look for alternatives to fresh water before submitting an application to Alberta Environment. Alternative sources may be more expensive, but a company will not automatically be able to use cost as a justification for not using an alternative water source. Under the new three-tier approach, the search for alternatives must be most strenuous in areas with existing or historical water shortages (Tier 3) and for large-scale projects anywhere in the province and all projects in developed areas (Tier 2).

Second, since 1989 Alberta Environment and the EUB have required water recycling for all in situ projects using more than 500,000 m^3/year of water, writing the recycle rates into the approval for a scheme.[500,501] The *Water Conservation and Allocation Guideline for Oilfield Injection* requires companies to "maximize the recycling of water" for projects of all sizes.

The Advisory Committee on Water Use Practice and Policy identified the need for research and knowledge to facilitate reduced water consumption and reduce losses of water from the hydrological cycle.[502] The Canada West Foundation consultation identified lack of innovation within the current policy framework and a failure on the part of government to integrate new scientific knowledge into public policy as a barrier to increased water conservation.[503] The Petroleum Technology Alliance of Canada also recognized this deficiency by holding a Water Efficiency and Innovation Forum in 2005, while the Alberta Energy Research Institute had earlier sponsored a report to identify research needs relating to water.[504] In addition, the Alberta

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[499] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources.* Drayton Valley, AB: Pembina Institute.

[500] Alberta Energy and Utilities Board. 1989. *Water Recycle Guidelines and Water Information Reporting for In Situ Oil Sands Facilities in Alberta*, http://www.eub.gov.ab.ca/BBS/requirements/ils/ils/il89-05.htm.

[501] Most, but not all, in situ oil sands projects that use steam require more than 500,000 m^3 water a year. See Table 2.5.

[502] Alberta Environment. 2004. *Advisory Committee on Water Use Practice and Policy: Final Report,* p. 22, http://www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf

[503] Wilkie, Karen. 2005. *Balancing Act: Water Conservation and Economic Growth.* Canada West Foundation, p. 21, http://www.cwf.ca/

[504] Peachey, Bruce. 2005. *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* [page #?] http://www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf

Ingenuity Centre has water as one of its themes and has started supporting research in this area.[505] While the work of the Innovation and Science Ministry, agencies such as the Alberta Energy Research Institute, and government-supported industry groups such as Petroleum Technology Alliance Canada is an essential aspect of innovative initiatives, both industry and government need to make more effort to develop innovative technology.

As was noted above, the current policy framework contains only limited direct provisions to encourage innovation and the use of the best available technologies and processes with respect to water use by the oil sector. In particular, the policy framework neither requires nor drives innovation in the oil industry with respect to water consumption, and for the most part the use of best available technologies or processes with respect to water use are not required.

Proposed Policy Response: The government of Alberta needs to drive innovation, require the implementation and research of new technologies to reduce water use (especially in water-short areas) and work with the oil sector to ensure that it is on the cutting edge with respect to technology development and implementation for water use.

5.2.4 Adaptive Policy Framework

The Need: An appropriate policy framework for water use needs to be able to adapt to annual and long-term changes in socio-economic, geographic and climatic conditions.

The Issue: Alberta's current system for allocating water rights, based on the first in time, first in right principle, with numerous water allocations granted in perpetuity, is inflexible and outdated.

This system is based on values formed 100 years ago and limits these values from evolving to reflect today's knowledge and priorities. As was described earlier in the report, water licences in Alberta are prioritized by the age of the licence. While new water licences, issued under today's *Water Act*, are granted for a fixed period of time (usually ten years), most of the licences issued under the previous *Water Resources Act* have no expiry date and have not been subject to assessment for potential environmental impacts or the appropriateness of the magnitude of the allocation. Allocations from surface water are largely based on the assumption that over the long-term flows do not vary, however flows are varying due to changing climate and shrinking glaciers. At the same time, licences granted in perpetuity do not allow allocations to be adjusted over time to reflect changes in water use priorities. In the case of the oil sector in Alberta, water licences issued under the previous *Water Resources Act* will only expire when the project they are tied to is complete. Only at that time are allocations returned to the Crown, either voluntarily or under restricted circumstances.

Proposed Policy Response: The government of Alberta needs to replace licences issued in perpetuity to the oil sector with term licences that respect short- and long-term variations in water supply, are protective of ecological integrity and are precautionary and responsive to the risk of climate change.

5.3 Policy response

In the section above we identified a number of reasons why the current policy framework related to water consumption by the oil sector fails to encourage water conservation and limit water use

[505] http://www.albertaingenuity.ca/grants_awards/ing_research_cenP_water_expertise.php

by the sector. For each of the existing policy gaps, we also identified the required government response. The table below summarizes the current gaps as well as the associated policy responses.

Table 5-1 Gaps in existing policy framework and proposed policy response related to water use by the oil sector

Policy Gap	Policy Response
Insufficient data and information on which to base policy decisions.	The government of Alberta needs to complete a comprehensive and publicly available inventory, which should be updated on a regular basis, of the water balance in each water basin in the province. Particular attention must be paid to gaining more information on the groundwater resources and in filling the information gaps identified by the Advisory Committee.
Lack of full cost accounting in water pricing schemes and thus a lack of direct financial incentive for oil companies to use/divert less water than that which has been allocated through the licensing process.	The government of Alberta should take a full cost accounting approach to water management for the oil sector in the province. That means having prices reflect not only administrative and infrastructure costs, but environmental and resource depletion costs too.
Lack of innovation and limited requirements to use best available technologies and processes for conserving water in the oil sector.	The government of Alberta needs to drive innovation, help develop and implement new technologies and ensure that the oil sector is on the cutting edge with respect to technology development and implementation for water use.
Lack of an adaptive policy framework.	The government of Alberta needs to replace licences issued in perpetuity to the oil sector for water allocations with licences that are in place for a fixed period of time and subject to evaluation and assessment.

In the remainder of this chapter we assess how the government could accomplish the policy responses identified above. We identify a number of policy options to respond to these gaps and discuss how they might be pursued in the Alberta context. We focus our assessment in particular on the need to drive innovation and the need for a full cost accounting framework for water management. In the case of information and data gaps and the need to build a more adaptive policy framework, the policy options are more obvious. For information and data gaps, the government should strive to anticipate future information needs related to water use in Alberta and begin collecting relevant, high-quality baseline data now. It is important for the government to stay one step ahead of information and data needs to ensure that the lack of such knowledge does not hinder future water management.

With respect to adaptability, the government should establish and commit to a timeline and process for transitioning to a system where water licences within the oil sector are granted for a fixed period of time. As part of that process, the government needs to consider whether companies exchanging permanent licences for term licences should receive financial compensation. The shift from permanent licences to term licences should be announced well in advance of implementation to give companies time to adjust to the pending policy change.

In the sections below, we assess specific policy options available to the government of Alberta to move towards full cost accounting and drive innovation within the oil sector.

OECD governments use a range of policy instruments to manage water-related issues and overcome barriers related to water conservation and pollution. These include water pricing, reducing or abolishing subsidies, tradable allocation permits or licences, pollution charges, effluent limits and standards for pollution discharges to water bodies.[506] Other policy instruments in use include disposal charges, tradable pollution permits, regulations requiring or providing incentives for the use of particular technologies and voluntary agreements. [507] Some policies, such as pollution charges and tradable pollution permits, are primarily intended to reduce or eliminate water pollution. We limit our analysis to a sub-set of policies, specifically those that relate to reduced water consumption and those that respond to one of the gaps identified above. The specific policy options and/or changes needed to respond to these gaps are assessed below. For each policy that we describe within the context of the oil sector, we

- identify its specific design features,
- discuss the extent to which it provides an incentive for water conservation,
- comment on the potential scale of administrative requirements, and
- briefly describe its application in other jurisdictions.

In the final section of this chapter we summarize the policy assessment and make recommendations on what actions the provincial government should take to reduce water use by the oil sector in Alberta.

5.3.1 Policy Options for Full Cost Accounting

All Canadian provincial governments have the authority to establish fees on water consumption.[508] Indeed, several policy options are available to provincial governments to move towards full cost accounting for water use. A price can be placed on water through user fees or volume-based charges, auctioning of water licences to prospective users or the application of disposal charges on wastewater. In the sub-sections below, we discuss each of these policy options in more detail.

5.3.1.1 User fees for water consumption

What are User Fees for Water Consumption? User fees involve placing a charge on water use that reflects the volume of water consumed, as well as a number of other criteria including location, time of day, season, source of water, and user, and may be adjusted over time to reflect

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[506] Organization for Economic Co-operation and Development. 2004. The OECD environmental strategy: Progress in managing water resources. *OECD Observer,* April 2004.

[507] Organization for Economic Co-operation and Development. 2004. The OECD environmental strategy: Progress in managing water resources. *OECD Observer,* April 2004.

[508] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30. http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

changing conditions. Fees can be levied on the consumption of surface water or groundwater.[509] With such charges in place, water users are required to pay according to the amount of water they consume and site- and time-specific environmental and resource depletion costs.

Specific Design Features: An effective water pricing policy for the oil sector should be linked to the amount of water consumed and be designed to cover financial costs (administrative, monitoring and infrastructure requirements), environmental costs and resource depletion costs. The environmental costs will vary from one type of water use to another and a water pricing scheme should be flexible enough to account for these differences. For example, in the context of the oil sector, to provide an incentive for companies to switch from the use of fresh water to saline water, the use of saline water could be exempt from a water-pricing scheme or be subject to lower prices.[510] Likewise, water removed from the active hydrological cycle (as in the case of oilfield injection) or water use that results in significant changes in water chemistry/toxicity requiring dilution could be subject to higher charges than those applied to activities that only make temporary use of the resource and return it in its original state.[511] A comprehensive water pricing policy would also be designed to reflect other site- and time-specific considerations.

To maximize the effectiveness of a water pricing policy, it is necessary to know the amount of water used, the elasticity of demand for the water, the financial costs associated with administering the water pricing policy, any infrastructure costs, and the various uses of water as well as the associated environmental and resource depletion costs.[512] While quantifying the environmental and resource depletion costs associated with water use is a very difficult task, it can be said with certainty that such costs are not zero. An appropriate pricing regime would recognize this fact, use the best available current information to set initial prices and adjust them over time as scientific knowledge and environmental cost estimates improve.

Beyond covering administration, monitoring and infrastructure costs, the revenue from a system of user fees on water could be used to, a) establish a research and development fund dedicated to furthering innovation in the field of water conservation and demand management, and b) respond to data and information gaps.

While in principle, a full cost accounting framework should be applied across all sectors, regardless of the particular use to which the water is being put, in some cases governments, on behalf of citizens, give priority to particular users and exempt from the charge system those uses deemed to be the highest in priority.[513] For example, agriculture or municipal water users may be given priority over industrial water users and granted exemptions from a water pricing scheme. Such design features prevent allocations from shifting from those sectors that can not afford to pay unit charges to those sectors that can, thus protecting high priority water uses.

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[509] In this report, we examine the application of user fees to surface water consumption. However, another recent report examined groundwater permitting and pricing in Canada. See Linda Nowlan. 2005. *Buried Treasure: Groundwater Permitting and Pricing in Canada.* Report prepared for the Walter and Duncan Gordon Foundation, http://www.gordonfn.org/resfiles/Buried_Treasure.pdf

[510] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources.* Drayton Valley, AB: Pembina Institute.

[511] Griffiths, Mary and Dan Woynillowicz. 2003. *Oil and Troubled Waters: Reducing the Impact of the Oil and Gas Industry on Alberta's Water Resources.* Drayton Valley, AB: Pembina Institute.

[512] European Union. 2005. *Pricing and Long-term Management of Water,* http://europa.eu.int/scadplus/leg/en/lvb/l28112.htm

[513] In Alberta, household water use is given priority over other water uses.

Incentive Effect: Research and experience have demonstrated that, in general, industrial water use is sensitive to price and that economic instruments, such as water pricing, have been successful in increasing water conservation.[514] However, in the case of Alberta's oil sector, the potential impact of a pricing scheme on water consumption is still uncertain. The impact will be determined by the price charged for water, the existing cost framework for water (costs associated with water access and handling) and the availability of substitutes or alternatives to water consumption. While oil companies do not currently pay the government for each unit of water they use, there are practical costs associated with the use of water from their perspective, including the cost of intake stations or water wells, treatment, pumping and piping. The cost of accessing water for conventional EOR ranges considerably from one project to the next. For example, accessing water from an onsite shallow well may be less than $1.00 per cubic metre, while accessing water from a river several miles away would cost more, and, when the cost for drilling a new well is included, accessing saline water from a known but locally un-drilled zone could cost several dollars per cubic metre.[515] In waterflood operations there are also costs associated with the handling of water, which vary according to the age of the project and the volume of produced water that must be handled.[516] It is uncertain whether a user fee for accessing new water for old waterflood projects, which are marginally economic, will be a factor in determining the end of their economic life, since the volume of new water required is small, relative to the costs associated with the large volume of produced water that must be handled.

Even with high water prices, a company may not invest in technologies to reduce water consumption because, when making investment decisions, the company will select those options that maximize the return on the money invested, since this is what shareholders usually want. Thus, when given the choice of investing in reduced water use or investing in increased oil production, it is likely that a company would opt for increased oil production if by doing so they are able to increase profits and shareholder dividends. It is recognized that the most "successful" oil industry projects currently have a payback period of about two years. Projects with longer payback periods, such as most water conservation investments, have difficulty competing on a "return on investment" basis.

To be effective and reduce water consumption in an economically efficient manner, user fees would need to reflect administrative, monitoring and infrastructure costs as well as environmental and resource depletion costs. The environmental and resource depletion costs would need to vary from one watershed to the next to reflect ecosystem and scarcity considerations. To the extent that the final price is an accurate reflection of *all* of these costs, water conservation within a particular watershed will occur in a cost-effective manner.

Administrative Requirements: The current administrative framework in Alberta for issuing water allocations could be used to levy user fees on the oil sector. However, it would be better to

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[514] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30, http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

[515] Further information on costs provided by Bruce Peachey, personal communication, September 2005 indicates that freshwater costs for intake stations or wells, treatment, pumping and piping might cost $1–2 per m^3. For conventional oil production, the costs of handling produced water vary between $0.50 and $6 per m^3. These costs are high relative to other major users of water (e.g., water for cooling at thermal power plants or for irrigation).

[516] The cost handling of water produced with the oil is also variable. It can be as little as $1.50 per m^3 of oil recovered for a new waterflood with little produced water to as high as $100 per m^3 of oil for an older waterflood recycling project that has a water:oil ratio of more than 16:1 (that is, 16 m^3 of water are produced for every 1 m^3 of oil obtained from the ground). The high cost for an older waterflood operation is only economic when oil prices are high (e.g., oil at $50/barrel, or $300/m^3 oil). Bruce Peachey, personal communication, September 2005.

use the data on the volume of water being used, which companies are required to provide to the EUB. While the administrative requirements for a user fee pricing scheme are higher than those for a flat rate pricing scheme, in which the same price is charged regardless of how much water is allocated, the costs would not be excessive, since water use reporting is already required. Furthermore, any pricing scheme should be made to recover all costs associated with administering the scheme.

Experience Elsewhere: There are numerous examples of water pricing policies in place around the world. For example, about half of OECD countries levy water abstraction charges, usually on water consumed outside the public water infrastructure system, the majority of which is industrial water. Quebec recently levied water royalties on commercial water users.[517] The Netherlands has two water charges: one levied by the provinces for groundwater protection, the other levied by the state within the general taxation regime. In Belgium, a charge is placed on industrial abstraction of groundwater. The proceeds from the charge are dedicated to a groundwater protection fund.[518] China uses effluent charges and water pricing to encourage industrial water conservation.[519] A significant development in this regard, the European Union has adopted the Water Framework Directive. This directive requires the recovery of both financial and environmental costs of water services for the residential, industrial and agricultural sectors.[520,521]

5.3.1.2 Tradable allocation licences

What are Tradable Allocation Licences? Under a tradable allocation licence system, a maximum limit is placed on the amount of water consumed or diverted.[522] The limit can be established on a sectoral basis (e.g., for the oil and gas sector), or more broadly (e.g., for a number of sectors combined). It can also be established on a watershed basis. To achieve conservation objectives, the total number of licences (and hence the amount of water consumed or diverted) is set at a level that is protective of ecological limits (e.g., IFN) and can be reduced over time. Water users must possess water licences that reflect their water use. The sum of all licences is equal to the total limit on water use. In situations where water supplies are uncertain, permits can also be defined as shares of a total rather than an absolute volume of water.

Under a full cost accounting approach, tradable licences should be distributed through an auctioning process. With an auctioning system, water users would submit bids for water licences and the licences would be granted to the highest bidders. Distributing licences through such a system provides an incentive to conserve water so that the number of licences initially obtained

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[517] Province of Quebec Provincial Budget, 2006-07. http://www.budget.finances.gouv.qc.ca/budget/2006-2007/en/pdf/BudgetBrief.pdf

[518] Organization for Economic Co-operation and Development. 2003. *Water Management: Performance and Challenges in OECD countries.* Paris, France: OECD.

[519] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30, http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

[520] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30, http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

[521] Information on the EU Water Framework Directive is available at http://europa.eu.int/comm/environment/water/water-framework/overview.html

[522] This kind of a policy is often referred to as tradable allocation permits. We are referring to tradable allocation licences to be consistent with terminology used throughout this report.

is limited to only those that are needed.[523] Once obtained, the licences can be bought and sold amongst licence holders.

Tradable licence systems provide a firm upper bound on the amount of water use or diversion that takes place in a given time period and thus provide a means to limit water use and achieve conservation goals. A system of tradable licences provides flexibility on how the cap on water consumption is achieved and ensures that water use reductions are achieved at the lowest possible cost. Additional flexibility results from the fact that the total amount of water allocated through licences can be adjusted over time to reflect changing conditions. For example, the government can buy back licences as a means to reduce the total amount of water allocated.

Specific Design Features: While the number of tradable allocation licence or permit programs is growing, in many cases, as in Alberta, the licences, although tradable, are not auctioned to users. Thus, while there is still an indirect incentive to water users to reduce water use and sell excess licences, in many cases governments are not charging for water consumption. As indicated above, this means that water users have no direct incentive to reduce their water consumption.

A tradable allocation licence policy, while an effective way to encourage efficient water use, is complex, involving many details and specific design features. For example, the degree to which trades could take place between different water users, if at all, would need to be determined (to prevent water users that can afford to do so from purchasing extra licences at the expense of other sectors). As well, the question of whether non-water users (such as conservation organizations) could buy licences would need to be answered. Such a policy requires very detailed information on existing water removals by the various users. Water flows and recharge rates would be required on a watershed-by-watershed basis and may also be required on a smaller scale such as a reach–by-reach basis. Before licence trading takes place, a regulator needs to ensure that IFN for each watershed in which trading might occur are maintained and local shortages are avoided (as is done in Alberta, to a limited extent, through the government's ability to withhold up to 10% of the volume of water transferred). A mechanism to deal with low flow years and reduced average flows over time is also needed. An overall cap on the volume of water available for trade, with the ability to withhold a portion of the water or adjust the volume of water available for trade for ecological reasons, is an important policy feature.[524]

Incentive Effect: Allowing the transfer of licence amongst users is an efficient way to increase conservation. Water users who can reduce water consumption most cheaply will do so and sell extra allocations, and those that face high costs of water conservation will prefer to purchase licences. Experience with these programs in other jurisdictions has revealed that they are capable of increasing water use efficiency.[525]

Administrative Requirements: The administrative requirements for such a program can be significant; however these requirements depend on the scope of the policy and the number of trades that takes place in any given period of time. Experience with water trading schemes in

[523] The other way to distribute permits is through a system of grandfathering in which allocations are granted based on historical use. Under a system of grandfathering, water users do not pay according to the number of permits in hand and there is no incentive for water conservation. Indeed, such a system rewards those that have traditionally consumed more water by allocating more permits to them.

[524] The government of Alberta is able to withhold up to 10% of the water being transferred in any transfer that takes place within the Alberta system.

[525] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30, http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

other regions has suggested a number of potential administrative challenges, for example, long time frames for trade approval.[526] The experience gained with the Alberta program to date will be useful in informing the level of administrative requirements.

Experience Elsewhere: The number of tradable allocation licence/permit programs is rising worldwide. One example of such a policy is the Northern Victoria Water Exchange in Australia. This program allows weekly trading of water allocations. Between the first and third year of operation, the amount of water traded through the exchange increased from 30,887 megalitres (Ml) to 60,117 Ml. The price of water has fluctuated between a low of AUD$30/Ml and a high of AUD$500/Ml depending on drought conditions and the availability of substitutes.[527]

5.3.1.3 Disposal charges

What are Disposal Charges? Disposal charges could be levied on used water sent for deep well injection by oil companies.

Specific Design Features: Disposal charges could be designed to provide oil companies with an incentive to encourage water recycling, where it is not already mandated. The rate charged should be sufficient to increase the competitiveness of recycling as an alternative to disposal, it should be directly linked to the volume of water disposed of, and also be related to the amount of pollution produced.

In addition to covering the administrative costs associated with collecting the disposal charge, the revenue from the fee could be placed in a dedicated “water management” fund. Among other priorities, the proceeds from the fund could be used to further research and development related to used water recycling and disposal, as well as groundwater protection in Alberta.

Incentive Effect: Disposal charges have been demonstrated to provide incentive to reduce waste. For example, Denmark implemented a tax on the disposal of non-hazardous waste in 1987. Between 1985 and 1993, reuse and recycling in Denmark increased from 21% to 50% of the total amount of waste generated. During the same time period, waste going to landfill dropped from 57% to 26%.[528] Since the introduction of Norway’s waste disposal charge, the portion of household waste going to landfill has declined from 43% to 24%.

In the context of the oil sector and water consumption, disposal charges would be applied to the disposal of used water into deep wells. There is currently no charge for disposal of water into a deep well in the province of Alberta. To the extent that the water disposal charge is sufficiently high and adds to the other costs of deep well injection, there will be an added incentive for water recycling and, as a result, innovation and technology development may increase. Even in cases where recycling is not a viable option or it is more profitable for companies to invest in increased oil production rather than reduced water disposal, placing a price on water disposal is still important from a full cost accounting perspective.

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[526] Marbek Resource Consultants with Dr. Steven Renzetti. 2005. *Analysis of Economic Instruments for Water Conservation. Final Report.* Submitted to Canadian Council of Ministers of the Environment, Water Conservation and Economics Task Group. Ottawa: Marbek Resource Consultants Ltd.

[527] Bjornlund, Henning. 2003. Efficient water market mechanisms to cope with water scarcity. *Water Resources Development,* Vol. 19, No. 4, p. 553–567, http://www.utsc.utoronto.ca/~02wongwb/Bjornlund%202003.pdf

[528] Kruszewska, Iza. 1999. *The Effectiveness of Taxes in Reducing Waste,* http://www.flora.org/sustain/Mistake/Waste_Tx.shtml

Administrative Requirements: Oil companies that undertake deep well disposal are currently required to submit an application for approval for the location and purpose of the well. They are also required to report on all wastes disposed of in deep wells. Specifically, they must report on the source of waste, volumes disposed of, and waste characteristics.[529] This reporting system could form the administrative basis for applying disposal charges. Since companies are required to report on the volume of waste disposed of, they could then be levied a fee in accordance with that volume.

Experience Elsewhere: Disposal charges have been applied to solid waste going to landfill, waste water bound for sewage treatment plants, construction waste, and the disposal of hazardous substances, among other items. The main use of disposal charges up to now has been in relation to waste disposed of at landfills. Sweden currently imposes a charge of SEK 250 for each tonne of waste going to landfill. Similarly, Norway has a charge ranging from NOK 327 to NOK 427 per tonne of waste going to landfill. The actual amount of the charge depends on the environmental protection measures at the particular landfill.[530] Most municipalities charge residential and commercial water users a waste water treatment, or sewage, fee on the amount of water disposed of in municipal waste water infrastructure.

5.3.2 Policy Options for Driving Innovation

While the fees proposed above could drive innovation related to water conservation and waste reduction, other policy options may be needed if the pricing schemes are not sufficient to spur innovation and technology development and reduce water use by the oil sector. Two other policy options for driving innovation with respect to water use by the oil sector are technology/process-oriented regulations and incentives. These policies, described below, can be used alone or in combination.

5.3.2.1 Technology-/Process-oriented regulations

What are Technology-/Process-oriented Regulations? Technology- or process-oriented regulations require the use of specified technologies and/or processes or require water users to meet specified performance standards. In the case of the former, such policies are often referred to as best available technologies (BAT) or best available technologies economically achievable (BATEA). This type of policy requires that companies invest in specified technologies or process changes and then demonstrate that the required changes are in place. Regulations that establish performance standards allow companies to choose how best to achieve the standard on a company-by-company basis without prescribing the use of particular technologies.

Specific Design Features: Regulations that require the use of specified technologies, because they are inflexible and may require all companies to incur large expenditures, can be an expensive way to achieve conservation and innovation objectives. A study of 12 environmental problems in OECD countries where conventional command and control resources policies (such as BAT or BATEA) and/or economic instruments (such as water pricing) were employed

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[529] Alberta Energy and Utilities Board. 1994. *Injection and Disposal Wells: Well Classification, Completion, Logging and Testing Requirements.* EUB Guide 51, p. 12.

[530] Information on these and other economic instruments related to environmental protection are available in an economic instruments database housed at http://www.economicinstruments.com/

revealed that economic instruments are generally more efficient and promote more innovation.[531] On the other hand, regulations that require certain performance standards to be met but allow individual companies to determine how best to achieve those standards, while less efficient than economic instruments, are more efficient than BAT or BATEA regulations

In either case, to help alleviate costs for water users, technology- and process-oriented regulations can be combined with a package of incentives to facilitate the transition to the necessary technologies or performance standards. To keep adjustment costs to a minimum, such policies should be announced well in advance of their implementation and should be phased in over time. This allows companies to take advantage of normal technology turnover rather than switching out technologies before they have reached their end of life.

The pace of innovation can be accelerated by complementing regulations, such as those described above, with research and development initiatives. Such initiatives can be funded by user fees on water consumption or by the auctioning of water licences.

Incentive Effect: Regulations that specify the use of particular technologies or processes do not provide an incentive to water users to continually reduce their water use. Once the required technologies or processes are in place or the performance standard has been met, there is no incentive for water users to continue to increase efficiency. At the same time, however, to date, scientific and technological developments have significantly helped reduce leakage from water transfer systems and increase the technical efficiency of water use. Developments in areas such as desalinization of saline water and reuse of wastewater are increasing the availability of cost-competitive additional supply.[532] The use of technology-/process-oriented regulations can continue to push these and other innovations towards maximizing water conservation opportunities, especially when performance standards are continually increased.

Administrative Requirements: While the administrative requirements related to such a program are fairly small, there is a need for monitoring to ensure that the specific technologies or processes are indeed being used and that performance standards are being met.

Experience Elsewhere: As section 4 of this report has described, there are a number of technology-oriented options for reducing water consumption in the oil sector. To date, most regulations requiring the use of BAT or BATEA have focused on water pollution prevention rather than on water conservation. Water pollution control policies in Ontario require polluting firms to adopt BAT or BATEA to decrease water pollution.[533] Most modern environmental regulations are performance-based rather than technologically prescriptive. Examples in Canada include the federal Pulp and Paper and Metal Mining Liquid Effluent Regulations under the Fisheries Act.[534]

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[531] Harrington, Winston and Richard D. Morgenstern. 2004. Economic incentives versus command and control: What's the best approach for solving environmental problems? *Resources: Resources for the Future,* Fall/Winter 2004, Issue 152, p. 13–17.

[532] OECD. 2003. *Water Management: Performance and Challenges in OECD countries.* OECD Publishing.

[533] Renzetti, Steven. 2005. Economic instruments and Canadian industrial water use. *Canadian Water Resources Journal,* Vol. 30, No. 1, p. 21–30, http://pubs.nrc-cnrc.gc.ca/cwrj/cwrj1-05.html

[534] http://laws.justice.gc.ca/en/F-14/

5.3.2.2 Technology-/Process-oriented incentives

What are Technology-/Process-oriented Incentives? While regulations can be an effective way to meet conservation objectives, as was stated above, they can also be expensive. Regulations become increasingly effective when combined with an incentive mechanism. An incentive mechanism would partially be provided through the use of water pricing, but could be reinforced by using a portion of the revenue from the pricing scheme to finance direct incentives to invest in particular technologies or processes. For example, a water pricing scheme can be combined with a grant or tax benefit that makes investments in new and cutting edge water conservation technologies more economical. Likewise, incentives can be provided to companies that pursue alternatives to the use of fresh water, groundwater or surface water or to companies that achieve significant water reduction or recycling targets.

Specific Design Features: Incentives to reduce water consumption can be tied to particular technologies (such as the policy in the United Kingdom described below) or can be directly linked to the amount of water saved (as in the California example below). Linking the incentive directly to the amount of water saved provides significant flexibility in how the water reduction is achieved. It does not necessarily have to be tied to the use of particular technologies but instead can result from straight reductions in use due to more careful water consumption or otherwise. It allows water users to reduce water consumption in the most economical means available to them and receive a financial reward for doing so. Such incentives, however, should only be received if water use goes down beyond a certain threshold so that only those companies achieving significant water reductions are eligible for the incentive. The incentive should be funded by revenues obtained through user fees or licence auctioning. This ensures that a portion of the revenue collected from the oil sector would be returned to it, but places conditions on the return of the revenue.

Incentive Effect: This kind of policy provides a direct and on-going incentive to reduce water consumption or invest in water saving technologies or processes. Depending on the size of the financial incentive and the ability of water users to reduce water consumption, the incentive to conserve water can be significant.

Administrative Requirements: If well designed, the administrative requirements for this kind of policy will not be prohibitive. Governments, including the government of Alberta, already provide financial incentives to companies for various investments. These could be extended to include key equipment and capital investments that facilitate reduced water consumption. Implementing a grant program directly tied to reducing water use (as in the California example below) would be administratively more complicated, but still manageable. Such a program would require companies to demonstrate the amount of water saved and should require minimum levels of water conservation to be obtained before the incentive applies.

Experience Elsewhere: In the United Kingdom, companies that invest in water saving technologies and products are able to deduct 100% of the cost of the investment against income tax. This enhanced capital cost allowance provides an incentive for companies to invest in water saving technologies.[535] In California, industrial water consumers who draw large volumes of

[535] Information on this policy can be found at http://www.eca-water.gov.uk/

water are eligible for a grant for saving water. Specifically, high water industrial consumers can receive a grant of $154 for every acre-foot of water saved.[536]

5.4 Summary

In the sections above, we present detailed information on a number of policy options available to pursue objectives related to full cost accounting and innovation within the oil sector in Alberta. Policy options related to full cost accounting include user fees on water consumption, tradable allocation licences and disposal charges. Policy options related to innovation include technology- and process-oriented regulations and incentives.

A number of policy developments are underway in Alberta, especially since the introduction of the new *Water Conservation and Allocation Policy for Oilfield Injection.* Under the *Water for Life* strategy, the oil sector will be expected to introduce targets for increasing efficiency of water use.[537] We do not yet know what the impact of these changes will be on the use of water by the oil sector. The extent to which additional policy changes will be required to reduce water consumption will not be fully understood until the current policy changes have been implemented. However, we propose that the government should stimulate additional efforts at water conservation by implementing user fees on fresh water consumption (as opposed to water that is diverted, used and returned to the watershed) by the oil sector. They should then further evaluate other policy options if reduction targets are not met. These policy recommendations are outlined in Section 6.2

In this chapter we have also identified gaps in the current policy framework related to information and data as well as the need for a flexible policy framework. With respect to these issues, we recommend that the government

- expand data collection and reporting, complete a survey of existing water supplies and fill the information gaps identified by the Advisory Committee.
- replace the licences that have been granted in perpetuity to the oil sector with licences that are in place for a fixed period of time.

[536] California's industrial rebate program for water conservation is described at http://www.mwdh2o.com/mwdh2o/pages/conserv/program02.html

[537] The Alberta Water Council is currently working on the establishement of water efficiency targets. If the targets established as part of the *Water for Life* strategy are sufficiently stringent, they could drive innovation and technology development.

6. The way forward

6.1 Cumulative impacts

The impacts of oil sands development in Alberta are enormous, including the impacts on water. Oil sands mining activities, both the mines and the huge tailings ponds containing wastewater, are so extensive they are easily seen on regional satellite photos. While impacts from in situ activity are less evident on the surface, this development will extend over a much larger area of the province and the cumulative impacts of in situ recovery on groundwater may be considerable if not managed in a sustainable manner.

Production of bitumen from oil sands is expected to grow rapidly, more than doubling between 2005 and 2014.[538] With this growth will come a large increase in the demand for water, both for the in situ recovery of bitumen and for oil sands mining and upgrading. Drainage operations to prevent flooding in mining operations affect groundwater flows and there is risk that contaminants could migrate from tailings ponds into groundwater.[539] Already, there is concern that demand for water from the Athabasca River for processing and upgrading the mined bitumen may result in insufficient water to keep the river healthy at low flow periods during the winter. Yet the demand for further withdrawals from this river is likely to increase substantially.

The use of fresh groundwater for in situ operations is also increasing rapidly and much faster than anticipated, even though some companies are using saline water. The development is so extensive that, despite modelling, it is difficult to anticipate the cumulative effects from the development, especially as the rate at which aquifers recharge is often uncertain.

Since crude bitumen deposits underlie approximately one-fifth of the province,[540] and production could last more than 400 years at current rates,[541] the full development of this resource could put widespread pressure on water resources in some areas. It is essential to examine the cumulative effects of this development and potential alterations in natural surface and groundwater flows that could result from climate change. Measures should be taken now to reduce the demand for fresh water and protect natural ecosystems.

Although the demand for fresh water for the enhanced recovery of conventional oil has been declining, there is concern about the use of any additional fresh water for this purpose in water-short areas of the province and in areas where demand for other purposes is increasing.

At the beginning of this report we asked three questions:

- Will water be a constraint on oil sands development?

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[538] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm

[539] National Energy Board. 2004. *Canada's Oil Sands: Opportunities and Challenges to 2015, An Energy Market Assessment*, p. 68, http://www.neb-one.gc.ca/energy/EnergyReports/EMAOil sandsOpportunitiesChallenges2015/EMAOil sandsOpportunities2015QA_e.htm

[540] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2–4, http://www.eub.gov.ab.ca/bbs/default.htm

[541] Alberta Energy and Utilities Board. 2005. *Alberta's Reserves 2004 and Supply/Demand Outlook/Overview.* Statistical Series (ST) 2005-98, p. 2 and 3, http://www.eub.gov.ab.ca/bbs/default.htm In 2004 Alberta produced 63 million m^3 of crude bitumen and the remaining established reserves were 27,662 million m^3. The ultimate potential recoverable is almost twice the remaining established reserves.

- Will oil sands development jeopardize the sustainability of water resources in northern Alberta?
- In areas of the province where water resources have already been over-allocated, can the use of water for conventional oil recovery be reduced?

From our review of the situation we can now answer “Yes, yes and yes.”

- Water will be a constraint on oil sands development.
- Oil sands development will jeopardize the sustainability of water resources in northern Alberta.
- Use of water for conventional oil recovery in areas of the province where water resources have been over-allocated can be reduced.

What must be done to resolve these issues? In the following sections we propose our vision for the future and make recommendations on specific actions that need to be taken to achieve that vision.

6.2 A vision for the future

When developing our recommendations for the management of water used by the oil industry in Alberta, we had before us a vision for the future: All oil projects, whether for mining, in situ production of bitumen or conventional EOR, should be planned and implemented to minimize negative impacts on water. Specifically, to conserve fresh groundwater and protect aquatic ecosystems in surface waters, all projects, current and planned, should do the following:

1. Avoid the use of fresh groundwater whenever possible.
2. Minimize the use of surface water.
3. Give priority to the use of saline water, especially water that is a produced as a by-product of adjacent operations (e.g., produced water associated with oil, gas or CBM recovery) where it can replace water from other sources.
4. Minimize the amount of waste disposal from water treatment processes, which also means restricting the use of saline water as much as possible where it must be treated before use.
5. Maximize recycling of used water.
6. Evaluate the life-cycle impact of different technologies and implement those that minimize water use and other environmental impacts.

To facilitate the improvements described above, we envision the government of Alberta managing the water use by the oil sector as follows:

1. Policy decisions and measures are based on comprehensive, readily available and up-to-date scientific knowledge and data.
2. Policies support a full cost accounting approach to water management.
3. Policies drive innovation, help develop and implement new technologies and ensure that the oil sector is on the cutting edge with respect to development and implementation of technologies to reduce water use.
4. The policy framework is adaptable, in order to respond to annual and long-term changes in socio-economic, geographic and climatic conditions.

6.3 Recommendations for water conservation and management

The recommendations identified below relate to policy, information requirements, regulation, and technical developments. Some apply to the entire province, while others are specific to one part of the oil industry. Some propose new policies while others advise on the implementation of policies that already exist.

6.3.1 Introduce policies to reduce water use

Effective water management requires a comprehensive policy framework that is based on solid data and scientific knowledge, takes into account that water resources are public, ensures that water is used for the most worthy purposes, prevents wasteful use of the resource, and provides adequate protection for ecosystems. Flexibility needs to allow for changing objectives and priorities over time.[542] As described in Chapter 5 of this report, the current policy framework in Alberta related to water use by the oil sector does not ensure minimum water use. There are gaps in the current policy framework and barriers that limit reduced water use by this sector. To respond to these gaps and overcome barriers, a combination of policy changes are needed. Specifically, we recommend that the government begin by establishing water use targets for the oil sector, implementing user fees on fresh water consumption (as opposed to water that is diverted, used and returned to the watershed) by the sector, and further evaluating other policy options if reduction targets are not met.

The targets should be increasingly stringent over time to drive innovation and push companies to continually reduce water use. User fees should provide an incentive for companies to use saline water instead of fresh water by making the use of saline water more economical in relation to fresh water.

Revenue from user fees should be placed in a dedicated “water management” fund to finance administrative costs and research and development, and to respond to data and information gaps especially those related to groundwater resources. To the extent that the price of water is an accurate reflection of all costs, and conservation targets for fresh water use are not achieved within a prescribed timeframe, the government would need to consider other, complementary policies. Such policies might include a comprehensive tradable allocation scheme, disposal charges on wastewater, and technology- and process-oriented regulations and incentives.

The implementation of user fees and water use targets, along with the flexibility to re-evaluate water allocations on a regular basis and having sufficient data and information on which to base future policy decisions, will help respond to gaps in the current policy framework.

6.3.2 Improve information on regional surface and groundwater quality and quantity

One of the fundamental issues with respect to water management for the oil industry is the lack of detailed information on which to base decisions about water allocations. Alberta Environment needs a comprehensive surface and groundwater monitoring system and database, with sufficient resources to continually review trends and the ability to take immediate corrective action if surface flows are insufficient to meet IFN, or aquifers show signs of being depleted. Regulatory

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[542] Teerink, John R. and Masarhiro Nakashima. 1993. *Water Allocation, Rights, and Pricing. Examples from Japan and the United States.* World Bank Technical Paper Number 198. Washington, DC.

decision makers are currently being asked to make decisions on proposed oil sands mining and in situ operations in the absence of adequate information and analysis. We recommend that the government increase baseline information and research on regional surface water and groundwater quality and quantity. Several actions are required to implement this recommendation.

6.3.2.1 Improve groundwater monitoring

There is lack of provincial monitoring wells in Alberta, especially in the north. Groundwater monitoring is needed to evaluate water use and aquifer depletion as well as identify potential contamination resulting from production of bitumen. Alberta Environment has received a proposal for a Master Plan to address the problem,[543] and they must be given the resources to quickly implement it. The department should immediately

- incorporate all data from its own groundwater monitoring wells and those operated by companies into a new database.
- obtain adequate baseline data on groundwater quality and quantity through government-funded regional studies and observation wells and by requiring company-based monitoring before and during project starts.
- establish well-defined and unambiguous standards for the evaluation of groundwater resources. The highest standards must be required for testing an aquifer before long-term groundwater withdrawal is permitted and any uncertainties in the information must be clearly delineated. Monitoring and reporting requirements must also be stringent and the results must be scrutinized to provide early warning of any problems.[544]
- evaluate the information provided by the database to identify any problems with water quality or quantity.

This work should progress rapidly, since "[a]dvancing our knowledge of groundwater resources is a fundamental underpinning factor in sustainable future economic development and proper watershed management in Alberta."[545]

6.3.2.2 Improve knowledge of Alberta's hydrometric network

As proposed in a recent report, Alberta Environment must improve its hydrometric and meteorological monitoring network.[546] This information is fundamental to understanding the natural water flows and losses in a region, which is the first step in managing the resource. It is essential to improve knowledge about shallow aquifers to ensure that the groundwater resources are not over-exploited. In northern Alberta, where there are few water wells, less is known about

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[543] Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report.* Prepared for Alberta Environment, p. 34.

[544] The most stringent monitoring might involve continuous water level monitoring and daily reporting of water production, in areas with limited aquifers, to monthly measurement of water levels and water production data.

[545]Komex International Ltd. 2005. *Groundwater Monitoring Networks Master Plan Development: Final Report.* Prepared for Alberta Environment, p. 42.

[546] AMEC Earth & Environmental. 2005. *The Review, Rationalization and Optimization of Alberta's Hydrometric and Meteorological Network: Final Report.* Submitted to Alberta Environment. Draft. August. AMEC Earth & Environmental is a division of AMEC Americas Limited and Mack, Slack & Associates Inc., Calgary, Alberta.

shallow aquifers than about deeper formations, since the upper parts of oil and gas wells are cased and cannot be logged.[547]

The AGS has an important task with respect to supplying information on both fresh and saline groundwater resources. We recommend that the AGS expand its work on understanding the hydrogeology of northern Alberta. This is especially important in areas where fresh groundwater resources are being used. The AGS must assess the capacity of shallow saline aquifers to supply water. Since deep saline aquifers recharge more slowly than shallow groundwater, it may not be possible to meet the increased demands from saline aquifers on a long-term basis in all areas. Information is needed about the availability and long-term replenishment of both saline and non-saline groundwater sources.

Alberta needs detailed, large-scale hydrological maps (showing both surficial and bedrock geology) for the whole province and work on this should start at once. However, many projects are likely to be proposed before such mapping can occur. Thus it is also essential to ensure that thorough baseline, site-specific studies of local conditions are conducted before licences are issued and these studies are used to contribute to a public database of information.[548]

6.3.2.3 Establish watershed water budgets and report on watershed management

We do not know with any degree of certainty the capacity of any of Alberta's basins to hold water. While this was not an issue when water resources far exceeded demand, it becomes increasingly important to understand the water balance in each basin as water withdrawals increase.

Watershed planners and practitioners recognize the need to understand the hydrologic cycle on a watershed basis. This means understanding the balance between the available water supply (from precipitation, runoff to lakes, rivers and wetlands and percolation into groundwater) and the volume that flows out of the basin, is removed from the active water cycle (e.g., through EOR) or passes into the atmosphere (e.g., through evaporation from water surfaces and evapotranspiration from vegetation).[549] The linkages between surface water and groundwater must also be understood to determine recharge areas and rates of recharge.

A water budget should be established for each major watershed, starting in those areas that face the most rapid expansion of projects in the oil sands region. It is essential to know how much water comes into a watershed, how is it distributed between ground water and surface waters, how much exists in the basin and how fast it leaves. It is also important to consider IFN. These numbers provide the absolute limits to what can be done in a basin, and, in an environment of climate change, they too are changing.

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[547] Water wells are logged, but these are mostly found in the inhabited areas of the province. Water well logs only show conditions in the upper part of the fresh water aquifers. Also, water well drillers are not trained geologists and cannot be expected to interpret any anomalies that occur in a log.

[548] As government work is budget-limited and must address a range of provincial priorities, the option is available for industry to conduct/pay for equivalent studies if they want to advance applications ahead of the government schedule. For example, the Multistakeholder Advisory Committee on Coalbed Methane/Natural Gas in Coal recommended a risk-based decision tree for water allocation where larger volumes would require information from regional studies.

[549] Watershed Science Centre. 2000. *Water Budget Analysis on a Watershed Basis.* Peterborough, ON: Trent University, http://www.trentu.ca/wsc/publications.shtml See also Canadian Water Resources Association. 2004. *Water Budget Analysis on a Watershed Basis*, http://www.cwra.org/About_CWRA/CWRA_Branches/Ontario/Water_Budget_Seminar/water_budget_seminar.html This seminar provides an overall review of the methodology for establishing a watershed budget.

Alberta Environment must work with the AGS to determine the long-term water balance in each basin and sub-basin, including the sustainable yield from aquifers. This means relating information on surface flows and groundwater to the volume of water withdrawn, not only for oil and bitumen production, but for other uses, such as municipal purposes. However, determining the sustainable yield of either surface water or groundwater resources is a complex task. Results will depend, for example, on the timing of measurements, the location of wells and the specific nature of development of each watershed.

The Athabasca River Basin should be a focus for watershed water budgeting, although due to its size it may be necessary to subdivide it and prepare separate reports for the in situ area and the mining region.

Detailed regional reports should be undertaken every five to ten years, depending on the rate of change in an area, based on information provided by the AGS and company monitoring, as well as Alberta Environment's monitoring networks. The regional reports provided for the Lakeland Industry Community Partnership indicate the type of information and scale that is appropriate for a region. Each report should

- summarize data on water quality and quantity for each river basin, highlighting any trends.
- indicate any sub-basin declines in groundwater levels and any unexpected or detrimental impacts as a result of water withdrawals.
- examine water use versus allocated volumes.
- identify areas where knowledge is insufficient.[550]

The reports should be submitted to the Alberta Water Council and be made available to the public.

6.3.2.4 Record the volume of water withdrawn from saline aquifers

As indicated in section 3.3.1, there are two reasons why it would be wise to start recording the volume of water withdrawn from specific saline aquifers:

1. Withdrawals of water from shallow saline aquifers may lead to the infiltration of water from overlying fresh water aquifers.
2. The volume of saline water in some areas is limited and once resources are depleted it may take thousands or millions of years for deep saline aquifers to recharge.

As the use of saline water increases, it would be prudent for the government to monitor the volume withdrawn from both shallow and deep saline aquifers, so that the cumulative impact of withdrawals is known. This would enable the government to know the extent to which shallow saline aquifers are being used and identify areas where freshwater aquifers might be impacted as water fills the void in underlying saline formations. Moreover, it would allow companies to adjust their operations before saline aquifers become depleted.

Companies already report the volume of produced water to the EUB, but the board does not request or record the data in a way that facilitates the identification of aquifers. Alberta

[550] See, for example, Parks, Kevin, Laurence D. Andriashek et al. 2005. *Regional Groundwater Resource Appraisal, Cold Lake–Beaver River Drainage Basin, Alberta*. Special Report 74. Alberta Energy and Utilities Board/Alberta Geological Survey.

Environment should work with the EUB to ensure that they collect data that can be used to monitor withdrawals from specific saline aquifers. This will provide baseline information and enable the identification of areas where future management of saline water may be necessary.

6.3.3 Improve regulation of oil sands development

6.3.3.1 Ensure regional management of cumulative effects in advance of further mining development

In 1999 the Government of Alberta set a policy direction for oil sands with its development of the Regional Sustainable Development Strategy (RSDS) for the Athabasca Oil Sands Region.[551] The RSDS identified 14 themes, six of which were related to water and all of which were granted lesser priority than air and land issues (Category B or C).[552] The multistakeholder CEMA was tasked with developing management objectives based on ecological thresholds, and providing recommendations to government for environmental management systems for each of the theme areas, on a priority basis. As a result of stakeholder concerns, work on fish habitat and surface water quantity has been given a high priority. However, despite this high priority and the growing urgency to address these issues arising from the increased pace of proposed mine development, CEMA was unable to complete this work by the end of 2005. As such, Alberta Environment unilaterally developed and implemented its interim IFN for the Athabasca River in January 2006, as described in section 3.2.1. While CEMA was unsuccessful in developing these management systems within the timeline required by the government, this should not detract from the value of CEMA as a forum for undertaking this work or from government imposed timelines. In fact, it is recommended that the government strengthen the role of CEMA and set clear objectives and firm timelines for the completion of its work on surface water quality and groundwater quality and quantity.

6.3.3.2 Ensure that EIAs contain a full analysis of cumulative impacts

Regulators rely to a considerable extent on information provided by a company EIA. It is essential that they are presented with an adequate analysis of the cumulative impacts of a proposed project.

The scope and quality of an EIA that must be completed to accompany an application for an oil sands mining or in situ project depends to a large extent on its Terms of Reference. The Terms of Reference for EIAs must prescribe the amount of baseline information required to ensure an accurate and rigorous assessment of potential environmental effects and their significance.

Furthermore, it is clear that additional research is required to support the analyses being presented in EIAs. Areas requiring specific attention include

- the additive or multiplicative impacts of water quality parameter interactions;
- the effects of widespread regional oil sands development on fish tainting and fish health; and
- detailed information on the nature and extent of potential cumulative impacts on groundwater.

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[551] See http://www3.gov.ab.ca/env/regions/neb/rsds/ for information on the RSDS.

[552] Category B (some work underway) included Theme 7 – Cumulative impacts on fish habitat and populations, and Category C (less urgency) included Themes 10 – Cumulative impacts on surface water quality, 11 – End pit lake water quality, 12 – Cumulative impacts on surface water quantity, 13 – Cumulative impacts on groundwater quantity and 14 – Cumulative impacts on groundwater quality.

6.3.3.3 Ensure the federal government fulfills its role with respect to EIAs

The federal government often has a major role to play in setting the terms of reference and reviewing EIAs. Under the *Canadian Environmental Assessment Act* they can review issues that fall under federal jurisdiction. This includes projects that have transboundary effects (e.g., impacts that could affect Saskatchewan) and those that may impact navigable waters, fish-bearing waters and Aboriginal lands. The DFO can use its powers under the *Fisheries Act* to limit a diversion if it would negatively impact fish habitat Thus the department can act as a trigger for federal involvement under the Canadian Environmental Assessment Act. Additionally, it should strengthen its role, which has become rather weak in recent years.

6.3.3.4 Review potential impacts before selling new mineral leases

The government should review the potential impacts of a project and not issue leases for new bitumen resources if the demand for water exceeds the sustainable supply. The Crown Mineral Disposition Review Committee currently conducts a review of new leases, but this committee has not been effective at addressing cumulative impacts on land, air or water. One of the issues this committee should consider is the availability of water for oil sands development. If sufficient information does not exist, no allocation should be made until baseline data has been collected and independently verified by Alberta Environment. If the development of a lease will require a large volume of water in areas where water supply is already limited, the rights to develop the bitumen should not be leased at the present time. The government should retain the rights until new technologies are available that can develop the resource with less or no water.

6.3.3.5 Develop and implement a formal policy for the issuance of water licences with provisions for staged reduction in water use for oil sands mining

While Alberta Environment has adopted the practice of granting phased water licences that reflect actual needs over the duration of a ten-year approval under the EPEA, this practice should be formalized as policy. Currently, there is little incentive for companies to undertake innovation that would result in a step-wise reduction, or the elimination of fresh water use for oil sands extraction. To address this, the EUB in consultation with Alberta Environment should develop water intensity objectives for the oil sands mining industry, and continually reduce these objectives over time. While the most pressing issue associated with water use is the impact that significant withdrawals from the Athabasca River may have on fish populations, a significant improvement in separating water from tailings would also serve to address the issues arising from the production of significant volumes of tailings.

6.3.3.6 Set clear expectations of tailings management and reclamation

There remains significant uncertainty as to the feasibility of future land and tailings reclamation. This uncertainty presents a challenge to the oil sands industry, regulators and stakeholders when considering continued growth in the terrestrial footprint associated with oil sands mining. Management of tailings, both in the short term and the long term, presents a significant risk that has not been adequately addressed.

To ensure that the work of the Reclamation Working Group of CEMA is completed in a timely manner, Alberta Environment should impose a timeline for this work to occur, after which it will unilaterally develop and implement reclamation criteria for terrestrial ecosystems, wetlands and EPLs.

In addition to completing the tailings management performance criteria, we recommend that the EUB and Alberta Environment undertake an assessment of both the short- and long-term risks of current tailings facilities and management practices. The results of this assessment should be used to inform future research and technology needs and the adequacy of the Environmental Performance Security Funds[553] currently collected from oil sands mine operators by Alberta Environment.

6.3.4 Rapidly develop and implement a provincial wetlands policy

Alberta's *Water for Life* Strategy noted, "Alberta's wetlands are under considerable pressure from land-use development. Public education, improved stewardship and careful land management are required to ensure protection of our existing wetlands." [554] Similarly, Alberta Environment's 2003 publication *Focus on Wetlands* provided an extensive overview of the importance of wetlands in the hydrologic cycle, both as habitat for a wide diversity of animal and plant species and as a tool for improving water quality.[555] While this publication alluded to the development of a wetland policy for public and private lands that states, "when development occurs on public lands, there must be no net loss of wetland area or function," [556] the only policy currently in place is the 1993 *Interim Policy for Wetland Policy in the Settled Area of Alberta."*[557] As such, there is currently no wetland policy that applies to the surface mineable oil sands region. In the absence of such a policy, decisions are being made in the region that will result in the permanent destruction of peatlands and a net loss of wetlands, with no efforts to apply the "no net loss" principle described in *Focus on Wetlands*. As the Wetlands Policy Project Team set up by the Alberta Water Council sets about the task of developing a new wetlands policy for Alberta, it is essential that they consider the unique problems relating to wetlands in the oil sands mining area.

It is widely acknowledged that peatlands cannot be re-constructed or reclaimed, hence oil sands mining operations will result in a permanent loss. However, the intent of no net loss of wetland area or function can still be met by ensuring that an area of wetlands equal to that of the destroyed peatlands is replaced and the important functions of peatlands, such as carbon sequestration, are offset in other ways.[558] While efforts to achieve (or minimize) no net loss of wetland area or function have been voluntarily made by some oil sands companies,[559] this has

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[553] For more detail on Alberta Environment's EPSF, see http://www3.gov.ab.ca/env/protenf/landrec/security.html

[554] http://www.waterforlife.gov.ab.ca/html/infobook/info4.html

[555] Alberta Environment. 2003. *Focus on Wetlands,* http://www3.gov.ab.ca/env/resedu/edu/focuson/wetlands.pdf

[556] Alberta Environment. 2003. *Focus on Wetlands,* p. 10, http://www3.gov.ab.ca/env/resedu/edu/focuson/wetlands.pdf

[557] http://www3.gov.ab.ca/srd/land/u_shorelands_wetlands.html

[558] For example, in an agreement with the Oil Sands Environmental Coalition, Canadian Natural Resources committed to "develop and implement carbon compensation for the loss of peatland carbon sequestration function due to the Horizon Project." Canadian Natural Resources Ltd. and Oil Sands Environmental Coalition. 2003. *Agreement between Canadian Natural Resources Limited and Oil Sands Environmental Coalition,* p. 8.

[559] For example, in an agreement with the Oil Sands Environmental Coalition, Canadian Natural Resources made the following commitment: "Where feasible, Canadian Natural will implement a wetland restoration or protection program as compensation for loss of wetlands from the Horizon Project. The compensation must meet requirements for long-term establishment in concert with the direction of no net loss planning, and will, therefore, require government sanction and protection for this to occur." Canadian Natural Resources Ltd. and Oil Sands Environmental Coalition. 2003. *Agreement between Canadian Natural Resources Limited and Oil Sands Environmental Coalition,* p. 8. Similarly, in an agreement between the Oil Sands Environmental Coalition and Shell Canada Ltd., Shell committed to "work with OSEC to identify a wetland offset project, such as an Alberta conservation program or Ducks Unlimited program and provide the funding necessary to plan and implement a project(s) that would provide wetland habitat within the boreal forest eco-region for migratory birds." Shell Canada Ltd. and Oil Sands Environmental Coalition. 2003. *Issue Resolution Document for the Proposed Jackpine Mine— Phase 1,* p. 12.

arisen from bilateral agreements with stakeholders as opposed to responding to pressure from government or formal policy.

6.3.5 Fully implement the Water Conservation and Allocation Policy for Oilfield Injection

The *Water Conservation and Allocation Policy for Oilfield Injection* applies to both in situ recovery and conventional oil recovery. The *Water Conservation and Allocation Guideline for Oilfield Injection* requires a company to look for alternatives to fresh water before applying for a water licence. The decision tree approach provides flexibility but it also allows a considerable amount of discretion for the director responsible for approving allocations. The effectiveness of this policy will depend on how it is applied. We make several recommendations for in situ and conventional oil recovery.

When the director considers a licence application for the use of fresh water we believe that s/he should do the following:

- Identify which areas may have water shortages in the future, due to climate change and increasing demand, as well as those that are currently short of water.
- Ensure that all reasonable alternative technologies and water sources have been examined, before making an allocation.
- Consider which technology/process will minimize the overall environmental impact of an in situ project. For example, while saline water should be used rather than fresh groundwater, there may occasionally be cases when it is preferable to use surface water if supplies are abundant. The use of saline water involves water treatment, which requires significant energy inputs (with associated air and greenhouse gas emissions) and the disposal of wastes from the treatment process. Deep well disposal is usually regarded as less harmful than landfilling of treatment wastes, but it requires suitable geological formations. Water treatment processes have been developed that avoid liquid disposal, but the resultant concentrated salt wastes must be landfilled. A leachate collection system can reduce the risks of groundwater contamination, but it is only effective while withdrawal of leachate and monitoring is continued. Landfills create a potential risk for future generations.
- Assess the full potential impact of different options for conventional EOR. For example, in a situation where there is no local source of saline water, determine if it is better to have a long pipeline to bring in saline water, or use local surface water if it is not needed for other uses or to meet IFN. The longer the saline water pipeline, the greater the risk that there may be a leak.[560]
- In water-short areas, be willing to shut in wells and delay production of the oil until other methods can be used to recover it, rather than have an extremely long pipeline bring saline water to the oil well.

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[560] Alberta Energy and Utilities Board. 2005. *Field Surveillance Provincial Summary 2004. ST57-2005*, p. 38, 43 and 52. In 2004 there were 20,578 km of water pipelines under EUB jurisdiction (operating, permitted, abandoned, discontinued and suspended) and 183 “incidents” involving water pipelines (ruptures, leaks and hits with no release). This is one incident for every 112 km of pipeline in 2004. Most of these pipelines would be for transporting saline produced water. The volume of produced water spilled in 2004 (from pipelines, wells, and so on) was 15,300 m^3.

- If voluntary measures do not work with companies that hold licences in perpetuity, use the provisions that exist in most permanent licences to modify licence volumes in water-short areas, especially during times of water shortage. This is important, since about half of the current licences for oilfield injection are held in perpetuity.
- Ensure that, when companies return unused allocations to the Crown, the water is used to meet the needs of natural ecosystems. Only if these are fully met should re-allocation of any water for other purposes be considered.
- Determine whether voluntary reductions in permanent licences have been adequate to reduce the demand for water for EOR, especially in water-short areas, or whether the Alberta government should change the legislation with respect to permanent water licences for oilfield injection.

Under the *Water Conservation and Allocation Guideline for Oilfield Injection*, Alberta Environment will assess reports from industry that outline the alternative technologies and water sources that a company has considered before applying for a water licence. Where necessary, Alberta Environment must make use of the provision to call upon the EUB to help evaluate such information. The EUB/AGS can, for example, help determine if an area is potentially suitable for EOR using CO_2, rather than water. The EUB will also know whether there are potential saline water sources in an area that a company has not included in their evaluation.

6.3.6 Promote best practices for drilling muds and fracturing fluids

The volume of water used for drilling muds and fracturing fluids is small compared to the amount of water used for EOR, but reductions in water use for these purposes may be important in water-short areas. The EUB should encourage companies to recycle water used for fracturing and adopt other best practices to minimize water use. It is noted that several companies have come forward with innovative management systems to address these issues. Reporting on successes and progress should also occur as both an encouragement to companies to take initiative and to show the public that the energy sector supports the *Water for Life* objectives.

6.3.7 Utilize transfers of water under the *Water Act* to regain water for instream needs

When approval is sought for a water transfer, as permitted under the *Water Act*, Alberta Environment should ensure the maximum of 10% of the transfer volume is returned to the Crown. If there is any shortage of water in a river, the entire volume should be retained to meet IFN.

Alberta Environment should report on the volume of water transferred in each river basin, the volume withheld by the Crown and the volume returned to the water basin.

6.3.8 Publish an annual provincial report water report

Alberta Environment should publish an annual report on activities to manage water resources in the province. This is the best way to determine progress in implementing measures to improve water management. The report should include information on monitoring, allocations and use of surface water and groundwater. It should, for example,

- show the volumes of water used for different types of oil recovery on a watershed basis, as well as the allocations. This will require completion of an integrated database, currently being developed, which is accessible to both Alberta Environment and the EUB.

- identify the activities that Alberta Environment and others have undertaken to improve knowledge of aquifers and water resources.
- provide an overview of the water balance for each of the main watersheds in the province, as soon as this information is available.
- summarize the number of inspections and actions to verify company monitoring and reporting and respond to complaints and the findings.
- report any leaks into aquifers (e.g., as a result of casing failures) and indicate whether any contamination has occurred.
- include a summary of monitoring at landfills used to contain saline sludges from water treatment processes.

The annual EUB Field Surveillance Provincial Summary Report indicates, in a comprehensive yet concise manner, the type of information that can be reported.

The water monitoring report should be submitted to the Alberta Water Council and made available to the public.

6.3.9 Ensure that government has adequate resources to better manage water

Alberta Environment, as the body responsible for managing Alberta's fresh water, needs the staff and resources to implement current programs and expand its activities. In the past the department has had to curtail some activities due to budget limitations. The recommendations made in this report need to be implemented quickly, which will mean engaging more staff at Alberta Environment.

The EUB and AGS must also have sufficient resources to improve water management and understanding of aquifers.

6.3.10 Encourage cooperation between industry and research bodies

Industry and research bodies are already working together through the Alberta Energy Research Institute and EnergyINet. The Alberta Energy Research Institute recognizes the need for more research with respect to water use. One of their goals is to support developments to reduce the use of fresh water by the energy industry by 50% by 2020.[561] The Petroleum Technology Alliance of Canada also helps identify and stimulate new research. They are already undertaking initiatives to encourage research to reduce water use. These organizations should realize the following actions:

1. **Increase research into the use of alternatives to water for in situ recovery.**

   Processes using solvents are currently being piloted. New processes to heat the bitumen, such as THAI, should be developed and evaluated for overall environmental impact as soon as possible.

[561] Alberta Energy Research Institute. 2005. *Alberta Energy Research Institute 2004–05 Annual Report*, p. 8, http://www.aeri.ab.ca/sec/new_res/pub_001_1.cfm

2. **Identify and test technologies that enable 100% recycling of produced water.** Various new water treatment technologies are being developed and the relative merits of different processes need to be determined.

3. **Determine to what extent voids created by the in situ removal of oil (and gas) at very shallow intervals will be filled with water from shallow aquifers.** Flows to fill the voids could further reduce freshwater supplies, which may already be depleted due to their use for in situ recovery (see "Voidage" in section 3.3.1).

4. **Further assess the impact of disposing large volumes of waste water, especially in the Ft. McMurray area.** The current requirements of EUB Directives 051 and 065 address routine operations with respect to deep well disposal, but research should look at the broader picture, such as the overall capacity of formations and where they outcrop. [562] It should, for example, determine if there is a risk that wastewater will push saline water into shallower zones. In the Fort McMurray area, where the containment zones are very thin and possibly fractured and the disposal zones are thin and relatively impermeable, it is important to explore for better zones regionally, and do research on alternatives to deep well disposal.

5. **Identify ways to reduce the barriers to the implementation of new technologies.** Various new technologies are being developed and pilot projects are underway to reduce the use of water or provide processes that do not require water. However, even when technologies exist, companies are often reluctant to adopt them. According to a recent report, "There's more incentive to maintain the status quo than to invest in potentially costly new technology."[563] Unless there is some motivation to introduce a new technology, there may be insufficient internal resources to evaluate and implement it. Some large companies in the oil industry may be reluctant to take a risk with unproven technology, because they are operating at a large scale. They only want to adopt "commercially proven" technology. In collecting information on in situ recovery for this report, it became apparent that there is a considerable difference between companies in their adoption of new technologies.

6.4 Future outlook

Success in managing Alberta's water resources depends on three main factors:

- Government regulatory policy
- Technological development
- Economic conditions

Government regulatory policy sets out what must be done. It is essential that Alberta Environment, the EUB and the AGS have the resources to fully implement the proposed

[562] The Alberta Energy and Utilities Board's Directive 051, *Injection and Disposal Wells— Well Classifications, Completions, Logging, and Testing Requirements,* and Directive 065, *Resources Applications for Conventional Oil and Gas Reservoirs,* address disposal volumes for individual projects. It is important to determine the total capacity of a formation to store liquids and the potential for the waste to move up dip to shallower depths.

[563] Petroleum Technology Alliance of Canada. 2005. *Barriers to Deployment of Environmental Technologies,* p. 8 and 9, http://www.ptac.org/eet/dl/eetreport0401.pdf

recommendations. The federal government must also play a role in improving knowledge of provincial water resources and in managing the industry to minimize impacts.

The Alberta Water Council and the water basin councils across Alberta have a very important role in monitoring the implementation of government policy and the environmental outcomes of that policy. They must regularly review progress achieved with current policies and recommend steps to improve policy and regulation, where necessary.

Research institutions need the resources to work with industry to develop new technologies that can reduce water use, but companies usually determine what processes will be adopted. They make their decisions on the basis of what is economically feasible, rather than on what is the optimum solution for the environment. Even a process that would give a positive economic return may not be introduced if a higher rate of return could be achieved by investing the same amount elsewhere. It is the government's responsibility to protect the environment and to adopt policies to ensure that this is achieved.

As the population and level of economic activity in Alberta increases, so does the demand for water. Climate change will likely increase the variability of precipitation and reduce the flows in rivers that are fed by mountain glaciers. Thus, we cannot assume that the same volumes of water will be available in the future as in the past. Summer river flows declined during the 20th century, and that century experienced fewer major droughts than had been seen in earlier years. Improving our knowledge and management of groundwater resources must be a top priority. This is not only important in settled areas of the province, but in northern Alberta where the resource could be most at risk due to the rapid development of the oil sands. The trends are troubling. In some places Alberta will soon have to decide which is more valuable and important to life: water or oil.

> "If sustainable development is to mean anything, such development must be based on an appropriate understanding of the environment—an environment where knowledge of water resources is basic to virtually all endeavors."[564]

[564] Report on Water Resources Assessment, WMO/UNESCO. 1991. Cited in William M. Alley, Thomas E. Reilly and O. Lehn Franke. 1999. *Sustainability of Ground-Water Resources.* U.S. Geological Survey Circular 1186, p. 2, http://pubs.usgs.gov/products/books/circular.html

Abbreviations and glossary

Abbreviations	
AGS	Alberta Geological Survey
AOSTRA	Alberta Oil Sands Research and Technology Authority
CBM	Coalbed methane
CEMA	Cumulative Environmental Management Association
CO_2	Carbon dioxide
CONRAD	Canadian Oil Sands Network for Research and Development
CSS	cyclical steam stimulation
CT	consolidated tailings
DFO	Department of Fisheries and Oceans (federal government)
EIA	Environmental impact assessment
EOR	Enhanced oil recovery
EPEA	Environmental Protection and Enhancement Act (Alberta legislation)
EPL	End pit lake
EUB	Alberta Energy and Utilities Board
ha	hectare
HCS	horizontal cyclic steam
IFN	instream flow needs
m^3	cubic metre
mg/l	milligrams per litre
MFT	mature fine tailings
MOSS	Mineable Oil Sands Strategy
NOx	nitrogen oxides
PAI	potential acid input
RSDS	Regional Sustainable Development Strategy
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
SO_2	sulphur dioxide
SWWG	Surface Water Working Group
TDS	total dissolved solids
THAI™	Toe-to-Heel Air Injection

Glossary	
anoxic	An adjective that means “without oxygen,” e.g., anoxic groundwater contains no dissolved oxygen.
aquiclude	An impermeable body of rock that may absorb water slowly but does not transmit it.
aquifer	An underground water-bearing formation capable of yielding water.
aquitard	A layer of rock having low permeability that stores groundwater but delays its flow.
asphaltenes	The heaviest and most concentrated aromatic hydrocarbon fractions of bitumen.
basal aquifer	A water-bearing strata located at the lowest portion of a stratigraphical unit. In areas within and adjacent to the mineable oil sands near Fort McMurray, the term refers to the lower water-saturated parts of the permeable McMurray formation, where the upper parts are bitumen-saturated.

bitumen	Hydrocarbons that are in a thick or solid form in natural deposits, often referred to as oil sands. The term also describes a thick form of crude oil that must be heated or diluted before it will flow into a well or through a pipeline.
brackish water	Salty or briny water. The EUB definition of brackish water is the same as for saline water, i.e., water with more than 4,000 mg/l total dissolved solids. However, sometimes brackish is defined as water containing between 1,000 and 10,000 mg/l totals dissolved solids.
connate water	Water trapped in the pores of rock during the rock's formation. May also be called "fossil water."
consolidated tailings	A mixture of mature fine tails and coarse tails. Consolidated tailings are prepared by combining densified tailings from cyclone underflow, mature fine tailings and gypsum. This consolidated tailings mixture is a homogeneous mass with a solids content ranging from 60 to 65% weight that densifies to 75 to 80% weight in a matter of months.[565] These thickened tailings contain a lower proportion of fine tailings and can be incorporated into a reclaimed landscape.
conventional crude oil	Oil produced by drilling wells and, if necessary, pumping. The oil is usually liquid at room temperature.
cyclic steam stimulation (CSS)	A type of thermal recovery process utilizing steam injection to enhance the recovery of crude bitumen (in situ oil sands).
enhanced oil recovery	A process in which a substance, typically water (saline, non-saline, produced or recycled) is injected into oil reservoirs to increase and maintain the pressure so that more oil can be extracted. The main type of enhanced oil recovery is water flooding, in which water is pumped into conventional oil field reservoirs. The injection of steam into heavy oil deposits is usually referred to as "enhanced recovery" but is sometimes also called enhanced oil recovery.
fine tailings, mature fine tailings	A gel-like material resulting from the processing of clay fines contained within the oil sands.
fresh water	In this report, it has the same meaning as non-saline water.
Green Zone	The mainly public, forested lands of northern Alberta and the Eastern Slopes that were originally withdrawn from settlement.
groundwater	Water that is underground, filling voids or fractures in rocks and voids between grains of unconsolidated sediments.
hydrocarbons	Liquid, solid or gaseous organic compounds, containing only carbon and hydrogen. They are the basis for almost all petroleum products.
in situ recovery	A process used to recover bitumen deposits buried too deeply—more than 75 m—for mining to be practical. It includes the use of steam for thermal recovery, although new methods using solvents, and so on, are being developed.
littoral zone	The depth zone between high water and low water. This zone provides habitat for submerged or partially submerged aquatic vegetation along the shoreline.
methane	The simplest hydrocarbon and main component of natural gas. It is also produced when organic matter decomposes.
methanogenesis	The formation of methane by microbes.
miscible flooding	An oil recovery process in which a fluid that is able to mix completely with oil is injected into an oil reservoir to increase recovery.
muskeg	A swamp or bog, consisting of a mixture of water and partly dead vegetation, often covered by a layer of sphagnum or other mosses.
naphthenic acids	A naturally occurring family of compounds found in bitumen.
non-saline water	Water with no more than 4,000 m/l of total dissolved solids (see saline water).
oilfield injection	Processes in which water, with or without another injectant (hydrocarbon solvent or CO_2), is injected through wells into conventional hydrocarbon reservoirs and crude bitumen/oil sands deposits (e.g., the Brintnell schemes that use water rather than steam) to increase or maintain the reservoir

[565] CANMET. 2002. *Advances in Oil Sands Mine Reclamation Technologies.*

	pressure so that hydrocarbon recovery is increased. Oilfield injection also includes processes in which water is injected as steam through wells into oil sand deposits or conventional heavy oil pools to lower the viscosity of the crude bitumen so that it can flow to a production well bore.
oil sands	Naturally occurring mixtures of bitumen, water, sand and clay.
overburden	A layer of sand, gravel and shale between the surface and the underlying oil sand. This must be removed before oil sands can be mined. Overburden underlies muskeg in many places.
polishing pond	A wastewater storage reservoir in which natural biologic and physical processes are used to improve water quality before discharge.
Quaternary period	The geological period that spans the time from 1.8 million years ago until the present day.
saline water	Water that has total dissolved solids exceeding 4000 mg/l.[566]
steam-assisted gravity drainage (SAGD)	A type of thermal recovery process used for enhanced recovery of crude bitumen. It uses two closely spaced horizontal wells: one for steam injection, the other for production of the bitumen/water emulsion.
synthetic crude oil	A mixture of hydrocarbons, similar to crude oil, obtained by upgrading bitumen from oil sands.
tailings	A slurry of water, sand, fine silt and clay particles, with residual amounts of bitumen, which is pumped to tailings ponds.
tar sands	An alternative term for oil sands.
thermal recovery	A process that uses heat to recover bitumen. Most commonly the heat is used to generate steam to warm the bitumen and reduce its viscosity.
total dissolved solids (TDS)	The measure of dissolved inorganic chemicals in water. Usually measured in mg/l.
upgrading	The process that converts the bitumen from thick, molasses-like oil, through the addition of hydrogen, into a lighter, higher-quality synthetic crude oil that can be sent to refineries.
water flooding	A conventional enhanced oil recovery process in which water is pumped into a well to maintain or increase the reservoir pressure so that hydrocarbon recovery is enhanced.
watershed	The area of land that catches precipitation and drains into a larger body of water such as a marsh, stream, river or lake.
wetlands	Areas of marsh, fen, peatland or water, whether natural or artificial, permanent or temporary, with water that is static or flowing.
White Zone	The settled regions of Alberta where agriculture is the most significant land use, including the grasslands and parklands of southern and central regions, and the Peace Country in the north.

[566] This is the definition in Alberta, as given in the *Water (Ministerial) Regulation, section 1(1)(z).*

Troubled Waters, Troubling Trends

Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta

The oil industry has a great thirst for water. With oil sands projects expected to double their output in just one decade, it's time for limits on how much freshwater is used to extract oil.

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